5.c.

ALJ/EA/nb

Decision No. 92557 December 30, 1980

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the matter of the application of SAN DIEGO GAS & ELECTRIC COMPANY for authority to increase its rates and charges for electric and gas service (NOI 21).	Application No. 59788 (Filed July 2, 1980)
In the matter of the application of SAN DIEGO GAS & ELECTRIC COMPANY for authority to revise its Electric Department tariffs to implement Schedule A-4 TOU, General Service-Time Metered.	Application No. 59785 (Filed July 1, 1980)

(Appearances are listed in Appendix A.)

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INTERIM OPINION

I. SUMMARY OF THIS DECISION

This decision authorizes an increase of $80,943,500 for the Electric Department and $14,957,900 for the Gas Department, for a total increase of $95,901,400 in gross revenues for test year 1981.

San Diego Gas & Electric Company (SDG&E) originally requested a total increase in gross revenues of $144.8 million for test year 1981. This request was later reduced to $107.7 million following the staff's investigation and publication of the staff report.

The return on equity of 14.5 percent remains unchanged from SDG&E's last general rate case based on a test year 1979. The resulting rate of return on rate base is 11.36 percent. This return reduces after-tax times interest coverage from 2.7 times last found reasonable to 2.3 times.

This decision increases expenditures for conservation programs for 1981 from $5.1 million to $11.3 million per year. This level of expenditure was adopted after close scrutiny of the company's proposed $15.2 million program and the Commission staff's recommended expenditure level of $13.1 million. This decision reduces 1981 advertising levels from a company-proposed level of $3.5 million to $2.0 million. The Commission did consider the views of customers expressed at the public hearings, regarding the need for expensive conservation programs notwithstanding extremely high utility rates which compel customers to conserve. However, the Commission believes a significant level of conservation expenditure is nevertheless necessary in order to avoid construction of costly new power plants.

A typical residential customer electric bill for 500 kilowatt-hours will increase from $48.54 to $52.76.

A typical residential customer heating-season gas bill for 100 therms will increase from $31.22 to $33.36.

This is an interim increase and further hearing will be held on SDG&E's 1982 test year, at which time the Commission will consider rate of return and other issues such as major changes in rate design.

II. INTRODUCTION

A. SDG&E'S REQUEST

SDG&E originally sought authority to increase its rates approximately $144.8 million (11.2 percent) annually at its estimated test year 1981 level of sales. This was reduced to an increase of $107.7 million (8.3 percent) as a result of various stipulations to the staff's estimates and transfer of issues to other proceedings. By department, this amounted to an increase annually of $91.2 million (9.5 percent) for electric and $16.5 million (4.9 percent) for gas service. In comparison the staff recommended a total increase of $68 million for all departments.

B. PROCEDURAL SUMMARY

SDG&E tendered a Notice of Intent (NOI) 21 on March 12, 1980 and it was accepted for filing on May 1, 1980. The application was filed July 1, 1980. The prehearing conference was held July 15, 1980, and the public witness hearings were conducted August 12, 13, and 14, 1980. Evidentiary hearings commenced September 15, 1980 and concluded October 27, 1980, at which time the case was submitted pending filing of concurrent briefs on November 17, 1980. The matter was heard before Administrative Law Judge (ALJ) Bertram Patrick.

SDG&E's A.59785 dated July 1, 1980 for authority to implement Schedule A-4 TOU, Electric General Service-Time Metered Rates, was consolidated with the general rate increase proceeding and is discussed in Chapter X - Rate Design.

We note that in its last general rate case, D.90405 based on test year 1979, we allowed SDG&E the opportunity to file its next general rate case with two separate test years. The objective was to shift the company to an even test year to smooth out the staff's workload under the Regulatory Lag Plan. Accordingly, this decision covers the first part of the dual test year (1981 and 1982) general rate increase application. A separate decision will cover the 1982 test year phase since further hearing is to be held on this matter.

Briefs were received from SDG&E, staff, city of San Diego (City), California Public Interest Research Group (CalPIRG), Executive Agencies of the United States (Federal Agencies), California Farm Bureau Federation (Farm Bureau), and California Community Colleges (Community Colleges).

C. MOTION TO DISMISS

Prior to commencement of the evidentiary hearings, CalPIRG made a motion to dismiss the application for the following reasons:

(a) The abbreviated and compacted hearing schedule adopted is an unjustified departure from past Commission policy and may produce a less than thorough investigation of the company's application by the parties involved in the proceeding.

(b) It has been the past policy of the Commission to schedule general rate case hearings in the geographical region of the consumers being affected by the increase. Since the schedule adopted included two weeks of hearing to be held in San Francisco, CalPIRG contends this will prejudice intervenors unable to be present in San Francisco due to financial limitations.

CalPIRG contends that the aforementioned time and geographical restrictions of the adopted hearing schedule will lessen the scope and potential effectiveness of their advocacy during this proceeding. It states that such a result is contrary to the Commission's expressed desire to encourage public involvement in its decision-making process. More importantly, CalPIRG believes that the San Diego ratepayers will not be served by their diminished involvement in this important rate increase application.

At the prehearing conference on July 15, 1980, the ALJ informed the parties that because of staff's budgetary constraints, it was necessary to have two weeks of hearing in San Francisco and the remaining four weeks, for a total of six weeks of hearing, would be held in San Diego. The objective was to have as many San Francisco staff members as possible testify at their home office location to cut down on travel time, waiting time, and living expenses otherwise necessary if they had to testify in San Diego.

On September 3, 1980 CalPIRG filed its motion to dismiss. On the first day of evidentiary hearing, September 15, 1980, the ALJ took CalPIRG's motion under submission and informed all parties that because of CalPIRG's inability to attend the two weeks of hearing scheduled in San Francisco, a motion by any party to have a witness recalled to San Diego for further cross-examination on a particular issue would receive consideration. Also, to assist parties unable to attend the hearings in San Francisco, the ALJ ordered copies of daily transcripts be made available in the Commission's San Diego office.

Regarding CalPIRG's objection to six continuous weeks of hearing, we note that the Regulatory Lag Plan prescribes a minimum of 12 days of hearing a month. It does not prescribe a maximum or place restrictions on the number of days of hearing in a week. While we agree that in this instance the schedule was compacted (for good reason),[1/] we do not agree with CalPIRG's assertions that there was insufficient time to participate effectively. We note that SDG&E's amended NOI, complete with work papers, was accepted by the Commission on May 1, 1980 and served on parties within five days. The application itself was filed on July 1, 1980 and served on parties receiving the NOI. Since evidentiary hearings did not commence until September 15, 1980, we believe all parties had ample opportunity to submit data requests to the company and make adequate preparation for the hearings.

We regret that CalPIRG was unable to attend the two weeks of hearing in San Francisco due to financial reasons; however, the record is clear the ALJ did take reasonable measures to protect CalPIRG's (and the ratepayers') interests by providing for witnesses to be recalled to San Diego upon a showing of reasonable cause. However, we note that CalPIRG did not choose to exercise this right.

1/ In recognition of the fact that staff would be fully occupied with Southern California Edison Company's and Southern California Gas Company's general rate increase proceedings, SDG&E agreed to file its A.59788 pursuant to a modified plan which provided for hearings to be scheduled after the submission of the other utilities' cases. Also, SDG&E agreed to limit the scope of its test year 1981 application to a "make-whole" presentation based on the return on equity found reasonable in its test year 1979 general rate case, D.90405.

We are satisfied all parties were given an adequate opportunity to evaluate A.59788 and to participate effectively in the proceeding. We conclude that the ability of CalPIRG or any other party to participate in the proceeding was not unreasonably hampered by the expedited hearing schedule set by the ALJ. Accordingly, CalPIRG's motion to dismiss is denied.

III. BASIS OF REQUESTED RATE INCREASE

SDG&E states that its request for 1981 is essentially to "make it whole" since without the requested rate relief, the company's ability to raise capital on reasonable terms would be seriously impaired. It is not asking for an increase in its authorized rate of return on common equity for test year 1981.

SDG&E claims that in the period since the last general rate case, D.90405 dated June 5, 1979, it has been confronted by the effects of double-digit inflation on the cost of providing utility service. Compounding this problem is the fact that some 59,000 new electric customers and 28,000 new gas customers will be added to the system. As a result, SDG&E expects to experience an increase in expenses for wages, materials, and services of 35 percent in 1980 over adopted 1979 levels, and an additional 17 percent in 1981 (57 percent overall).

Another major element of the rate request is proposed expenditure for conservation programs. While these programs are undoubtedly worthwhile in this era of high energy demand and costly supply, their benefits can be reaped only through the expenditure of sufficient monies to ensure their success.

In this opinion we examine the various factors that make up SDG&E's amended request for a $107.7 million increase in gas and electric revenues for test year 1981.

IV. PUBLIC WITNESS STATEMENTS

Commissioner Leonard Grimes presided at the public witness hearings held in Oceanside on August 12 and in San Diego on August 13 and 14, 1980. Evening hearings were held at both locations to provide SDG&E's customers with an opportunity to present their views on the rate increase filing.

Local TV, radio, and newspapers provided extensive coverage. A total of 290 customers attended and 99 made statements. While the majority of customers were older and on fixed incomes, there was good representation from all age groups, including younger customers struggling to raise families.

In addition to general opposition to the rate increase, the views of the customers are summarized as follows:

- Management inefficiencies are responsible for the company's financial problems.
- Expenditures for abandoned projects should be borne by the stockholders and not the ratepayers.
- SDG&E should tighten its own economic belt by improving management efficiency, eliminating waste, laying off employees, and doing the things other businesses do when times are difficult.
- The high cost of energy makes conservation a financial necessity and therefore expenditures for conservation programs are not necessary.
- TV and newspaper advertising for conservation and load management programs should be eliminated.
- Rates could be reduced if money is not spent on colorful pamphlets offering conservation suggestions.
- Customers practicing conservation should not be penalized with increased rates because SDG&E's sales are reduced.

- .Rates could be reduced by ending undergrounding of overhead utility lines.
- .New connections to the utility's system should pay a hookup fee.
- .Mobile home parks should not make a profit on the utility bill.
- .Employee discounts should be eliminated.
- .Businesses in SDG&E's territory are unable to compete with out-of-state competition because of SDG&E's high electric rates. A representative of Crystal Silica Company, a commercial customer with 80 employees, voiced his concern that his company's electric bill had risen faster than inflation (643 percent since 1973).
- .Rates should not be raised because of solar loans and insulation programs.
- .Wind and solar power should be used for generation.
- .Pronuclear and anti-nuclear views were expressed on San Onofre Nuclear Generating Plant.
- .More lifeline allowances should be available for air conditioning.
- .Lifeline allowances are inadequate and should be increased.

Generally, customers are angry that they received six rate increases in 12 months and that SDG&E's rates are the second highest in the country. They make no distinction between offset increases for higher fuel prices and those resulting from general rate increase applications such as covered by this proceeding. They are particularly concerned with the ability of senior citizens and those on low or fixed incomes to pay continued utility increases.

The Commission received 568 letters and three petitions containing 1,411 signatures protesting the proposed rate increase. The letters addressed the same concerns that the public witnesses spoke of. We will consider all of these concerns in our disposition of this matter.

V. STATEMENTS BY LOCAL BODIES

A. CITY OF SAN DIEGO (City)

William S. Shaffran, deputy city attorney, opposed the increase requested by SDG&E and questioned: (1) the amount of the increase, (2) management's prudence in certain areas, (3) the company's sales forecasts, and (4) the amount requested for conservation and the cost-effectiveness of these programs. The City was represented throughout the evidentiary hearings and vigorously participated in cross-examination of the company's and staff's witnesses.

B. COUNTY OF SAN DIEGO (COUNTY)

William D. Smith, deputy county counsel, presented a statement from the Board of Supervisors (Board). The Board called upon everyone - citizens, employees, government agencies, and utility companies alike - to make sacrifices and share in the austerity that is required of all segments of society in order to reduce our dependence on foreign oil. In addition, the Board called upon SDG&E to forego the requested rate increase.

The Board supported SDG&E's conservation programs and the Eastern Inter-Tie Project.

As part of its program to reduce dependence on foreign oil, the Board pointed to the energy conservation measures instituted by the County, which include: (1) development of an energy conservation policy, (2) delamping operations, (3) installation and refinement of a computerized energy management and control system for major County facilities, (4) monthly energy management reports, (5) energy audits, (6) installation of time switches, (7) replacing inefficient lighting, and

(8) additional light switching to provide more flexibility and control. As a result of these efforts, electricity consumption in eight major County facilities has decreased by 6.3 million kilowatt-hours (kWh), a reduction of 20 percent. A reduction of gas usage of 54 percent has been realized, and steam consumption has been reduced by 75 percent. Overall energy savings in these facilities, from the base year 1972-73 to 1979-80, are 57 percent.

Smith stated that the County is studying plans for cogeneration and has embarked upon a program to produce electricity from solid wastes which will convert 423,000 tons of solid waste each year into an estimated 25.5 megawatts of electrical energy. The program calls for a capital expenditure of nearly $200 million over six years.

Supervisor Jim Bates of the Fourth District, San Diego County, proposed that: (1) a consumer advocate with no financial interest in SDG&E be put on the Board of Directors, (2) stockholder dividends be reduced, (3) advertising expenses be eliminated from rates, (4) the County take steps to be totally energy independent, (5) public ownership of the gas and electric utility be studied, and (6) more emphasis be placed on renewable energy sources.

We commend the County for its active involvement in the areas of conservation and cogeneration.

C. BORREGO SPRINGS

Approximately 300 residents attended an informal meeting held by the Commission's Consumer Affairs Branch in Borrego Springs on October 14, 1980. The residents requested the meeting to protest the high level of electric rates and asked that the Commission give special consideration to the plight of desert communities.

They request the Commission consider higher summer lifeline allowances of at least 1,200 kWh for the months of July, August, and September instead of the present 400 kWh,[2/] and they want to bank unused lifeline allowances for credit against future consumption.

The residents state that because of an electric bill of $4,600 for August 1980, the owner of the only grocery store in the community has refused to stay open next summer. This means residents will have to travel 50 miles each way for groceries. They ask that lifeline allowances and reduced demand charges be considered for small businesses. They believe that desert communities will not be able to exist unless they are given special consideration.

D. POWAY UNIFIED SCHOOL DISTRICT

Doctor David Stine, representing the Poway Unified School District (District), stated that more and more educational dollars are being taken away from students in the classroom and are spent on utilities. He said that out of a budget of $34 million approximately $1.5 million is presently spent on utilities and the District will be in a real dilemma to find an extra $500,000 to pay higher utility bills for the next fiscal year. He complimented SDG&E for the assistance it had given the District with conservation measures. He stated that energy audits have been made of the 18 schools that serve the 15,000 students in the District. They have delamped and relamped, lowered water temperatures, put on water heater blankets, and employed some 25 measures to conserve energy. Doctor Stine asked that SDG&E be made to stay within a budget just like any public agency.

2/ D.90405 dated June 5, 1979 adopted an air conditioning lifeline allowance of 400 kWh to all customers in Zone V for the months of May through October.

VI. RATE OF RETURN

A. GENERAL

In its cost of capital presentation, SDG&E has kept frozen the return on common equity and updated the other cost factors, consistent with its commitment to minimize controversy in this proceeding. The company presented witness Williams to sponsor the rate of return showing in Exhibit 1. As a result of certain stipulations made to the staff's use of more recent financing data, the requested overall rate of return on rate base is 11.36 percent, with a corresponding return on equity of 14.50 percent, as shown in late-filed Exhibit 70. This compares to the staff's recommended rate of return of 11.22 percent overall, and 14.5 percent on equity.

B. RETURN ON EQUITY

A few comments are in order regarding the mutually recommended return on common equity of 14.50 percent. This level was last authorized for SDG&E in D.90405, based upon a 1979 test year. According to SDG&E, financial conditions have been much worse than was forecasted. Witness Williams testified that were it not for the company's policy in this proceeding to eliminate return on equity as an issue, the required level would be higher than 14.50 percent. Staff witness Quan testified that his cost rate recommendation of 14.50 percent, contained in Exhibit 16, was based upon an independent analysis that led him to conclude that such level is fair and reasonable for test year 1981.

Considering the above factors, we adopt as reasonable a 14.5 percent return on common equity for test year 1981.

C. BANKERS' ACCEPTANCES

The only area of dispute in the cost of capital is the proper cost rate to be used for the bankers' acceptances component of the calculation. Bankers' acceptances are financial instruments which have lives of less than a year and are used to finance fuel oil purchases. The company estimated a cost rate of 12.50 percent in 1981. The staff, on the other hand, used a cost rate of 10.50 percent.

Since interest rates have remained high with no signs of returning to "normal", we will adopt a 12.5 percent interest cost as reasonable for test year 1981 for bankers' acceptances. Based on the staff's capital structure, we calculate this will provide a 2.3 times interest coverage, a reduction from the previous level of 2.7.

D. ADOPTED RATE OF RETURN

Considering the above factors, our adopted capital structure and costs will translate to a 11.36 percent rate of return as follows:

Adopted Rate of Return

Component	Capitalization Ratios	Cost	Weighted Cost
Long-Term Debt	44.40%	9.43%	4.19%
Bankers' Acceptances	6.60	12.50	.83
Preferred Stock	12.75	8.44	1.08
Common Equity	36.25	14.50	5.26
Total	100.00%		11.36%

VII. RESULTS OF OPERATION

A. SUMMARY AND ADOPTED RESULTS

SDG&E and staff have estimated SDG&E's 1981 test year results of operation for the Electric and Gas Departments. The following Tables I and II present the final SDG&E and staff estimates and our adopted test year results of operation. Energy costs are excluded and revenues reflect base rates only.

TABLE I

San Diego Gas & Electric Company
Electric Department

RESULTS OF OPERATIONS

Test Year 1981

Item	At Staff (A)	Rates Company (B)	Adopted (C)	Authorized Total (D)	CPUC (E)
	(Dollars in Thousands)				
Revenues	296,643.7	282.943.0	282,930.1	363,873.6	363,023.5
Expenses					
Production	48,455.7	48,455.7	48,455.7	48,455.7	48,435.7
Transmission	6,793.2	6,931.4	6,920.3	6,920.3	6,745.3
Distribution	23,143.3	24,776.5	24,027.2	24,027.2	24,027.2
Customer Accts.	10,800.0	11,184.0	10,766.9	10,888.3	10,888.3
Marketing	9,289.8	9,289.86	6,685.0	6,685.0	6,685.0
A&G	42,314.1	43,401.0	42,613.5	44,189.4	44,068.4
Total	140,796.1	144,038.4	139,469.6	141,165.9	140,849.9
Wage Adjustment	1,147.2	-0-	-459.0	549.0	457.9
Total	139,648.9	144,038.4	139,009.7	140,706.9	140,392.0
Depreciation and Amortization	49,950.0	50,076.0	50,126.0	50,126.0	49,961.0
Taxes Other Than Income	14,141.0	14,957.0	14,141.0	14,141.0	14,095.0
Calif. Fran. Tax	792.7	-0-	-0-	7,474.1	7,455.0
Federal Income Tax	305.4	4,967.8	-3,514.9	26,734.3	26,665.0
Total Expense	204,838.0	204,103.6	199,761.7	239,182.3	238,568.0
Net Oper. Revenues	91,805.7	78,839.4	83,168.4	124,691.3	124,455.5
Rate Base	1,055,401.0	1,105,504.0	1,097,635.0	1,097,635.0	1,095,299.0
Rate of Return	8.70%	7.13%	7.58%	11.36%	11.36%

Staff and Company estimates reflect late filed exhibit 70.

Table II

San Diego Gas & Electric Company
Gas Department

RESULTS OF OPERATION
Test Year 1981

Item	At Present Rates: Staff (A)	Company (B)	Adopted (C)	Authorized (D)
	(Dollars in Thousands)			
Revenues	$ 56,253.0	$ 56,253.0	$ 56,253.0	$ 71,210.9
Expenses				
Gas Supply	(713.0)	(713.0)	713.0)	(713.0)
Storage	1,990.0	1,990.0	1,990.0	1,990.0
Transmission	1,745.7	1,708.7	1,708.7	1,708.7
Distribution	10,743.3	11,034.3	11,006.8	11,006.8
Customer Accounts	5,966.4	6,120.8	5,966.4	5,989.1
Marketing	3,820.0	3,820.0	2,888.0	2,888.0
A&G	11,337.7	11,741.1	11,437.0	11,794.0
Total	34,890.1	35,701.9	34,283.9	34,663.3
Wage Adjustment	(403.2)	-	(161.0)	(161.0)
Total	34,486.9	35,701.9	34,122.9	34,502.3
Depreciation and Amortization	8,535.0	8,541.0	8,541.0	8,541.0
Taxes Other Than Income	2,649.0	3,728.0	2,649.0	2,649.0
Calif. Franchise Tax	-	-	141.3	1,540.9
Federal Income Tax	(361.8)	(1,342.6)	-	5,905.5
Total Expenses	45,309.1	46,628.3	45,454.2	53,138.7
Net Operating Revenues	10,943.9	9,624.7	10,798.8	18,072.2
Rate Base	159,611.0	159,180.0	159,086.1	159,086.1
Rate of Return	6.86%	6.05%	6.79%	11.36%

(Red Figure)

Notes: 1. Present rates are rates effective January 20, 1980.
2. Staff and company estimates reflect late-filed Exhibit 70.

B. OPERATING REVENUES

1. General

There is a significant difference between SDG&E and the staff in the estimates of electric revenues. A summary of these differences is as follows:

Total Electric Sales (GkWh - millions of kWh)

SDG&E	Staff	Difference SDG&E Less Than Staff
10,334.28	10,917.38	583.10

Electric Revenues

SDG&E	Staff	Difference SDG&E Less Than Staff
At Present Rates		
$282,943,000	$296,643,700	$13,700,000
At Proposed Rates		
$409,573,000	$431,135,600	$21,562,600

There is no difference between SDG&E and staff estimates of revenues for the Gas Department.

The major reason for the difference in Electric Department revenue estimates between SDG&E and staff is a difference in the sales estimates. In addition, there is a difference in estimates for miscellaneous revenues due to refunds on lifeline sales ($203,000).

The following Tables III through VII show the staff's, SDG&E's, and the adopted estimates of sales and revenues at present rates and the gas margin for test year 1981.

Table III

Sales - Electric Department
Test Year 1981

Class of Service	Staff	SDG&E	Adopted
	(Millions of kWh)		
Residential	4,294.60	3,968.28	3,968.28
General Service	3,400.00	3,313.80	3,313.80
General Power	213.00	206.34	206.34
Industrial	2,440.75	2,299.77	2,299.77
Agricultural Power	164.31	148.60	148.60
Street Lighting	74.86	67.63	67.63
Resale	54.29	54.29	54.29
Other Sales to Public Authority	275.57	275.57	275.57
Total Sales	10,917.38	10,334.28	10,334.28

Table IV

Revenues at Present Rates - Electric Department
Test Year 1981

Class of Service	Staff	SDG&E	Adopted
	(Thousands of Dollars)		
Residential	$124,497.3	$115,374.0	$115,374.0
General Service	104,272.6	101,936.0	101,936.0
General Power	6,496.7	6,312.0	6,312.0
Industrial	44,835.2	43,917.0	43,917.0
Agricultural Power	4,379.5	3,986.0	3,986.0
Street Lighting	4,033.4	3,644.0	3,644.0
Resale	682.0	682.0	682.0
Other Sales to Public Authority	17.0	17.0	- *
Base Rev. From Cust.	289,213.7	275,868.0	275,851.0
Miscellaneous	7,430.0	7,075.0	6,872.0
Revenues	296,643.7	282,943.0	282,723.0

*Transfer of Department of Water Resources sales to ECAC per D.92496 in OII 56.

Table V

Sales - Gas Department
Test Year 1981

Class of Service	Staff, SDG&E, and Adopted
	(Thousands of Therms)
Residential	355,675
Nonresidential	202,266
Total Sales to Customers	557,941
Interdepartmental Sales	223,749
Total Sales	781,690

Table VI

Revenues at Present Rates - Gas Department
Test Year 1981

Class of Service	Staff, SDG&E, and Adopted
	(Thousands of Dollars)
Residential	$36,426.0
Nonresidential	12,775.0
Subtotal	49,201.0
Interdepartmental	5,676.0
Miscellaneous	1,376.0
Total Revenues	$56,253.0

In order that there will be no misunderstanding of the appropriate gas margin for the test year, the following summary sets forth our adopted results:

Table VII

Gas Margin
Test Year 1981

Item	Gas Margin ($000)
Authorized Rev.	$71,210.9*
Less Other Misc. Rev.	1,376.0
Total Authorized Gas Margin	69,834.9

* Based on a franchise and uncollectible factor of 2.5364%.

2. Sales Estimates

Both the company and staff used econometric models to estimate historical statistical relationships between sales and economic and noneconomic variables. A major difference between the company and staff lies in the structure of their respective models.

The issue of sales was vigorously contested by both staff and the company. An impressive showing was made by both sides. Staff and company witnesses provided competent testimony to support their positions. However, both sides were far apart on the level of electric sales for test year 1981. The staff and SDG&E estimates of total electric sales differ by 583.1 million kWh. The staff's higher estimate yields a revenue estimate at proposed rates that is $21.5 million greater than the company's.

Because of the large difference in sales estimates, the company proposed that the Commission adopt SDG&E's sales estimate for 1981, together with a refund provision that would operate if revenues based on rates, set using SDG&E's sales levels, exceed SDG&E's estimate. This proposal involves a balancing account with monthly entries comparing actual base rate revenues with the base rate revenue based on the company's monthly sales estimates as reflected in Exhibit 62. If the actual revenue exceeds the target revenue for that month, a credit equal to the excess base rate revenue would be entered into the balancing account. An opposite debit entry would be made if the monthly base rate target revenue exceeded actual. At year end 1981, or the date when 1982 test year rates are effective, whichever is later, if a net debit balance remains, the balancing account would be closed out and SDG&E would not seek to recover that undercollection from the ratepayer. If a net credit entry remains, the balancing account would be closed out and a credit equal to that overcollection would be made to the Energy Cost Adjustment Clause (ECAC) balancing account for the benefit of the ratepayers.

Staff has no objection to this company proposal so long as it applies to the 1981 test year only.

We should observe that if any level of estimated sales in excess of the company's were adopted by the Commission for setting rates, and higher sales did not materialize, the company would suffer a base rate revenue deficiency. If this happens, SDG&E will not have any chance to earn whatever rate of return is authorized. Therefore, we believe the proposed mechanism for 1981 will give the company a reasonable opportunity to collect the adopted base rate revenues while at the same time protect the ratepayer through the refund provision from a possible underestimate of sales by the company.

Accordingly, we will adopt SDG&E's sales estimate for test year 1981, subject to the above conditions.

3. Lifeline Refunds

Here the $198,900 difference between the company and staff is attributable to a negative entry to miscellaneous revenues proposed by SDG&E for base rate portions of the lifeline refunds made to electric customers consistent with Commission Resolution No. E-1833. This $198,900 amount is about one-third of the total base rate amount refund of $596,755, which the company proposes to amortize over three years beginning in 1981.

Resolution No. E-1833 of April 24, 1979 acknowledged that a number of SDG&E's residential customers might not be receiving their correct lifeline allowances. In order to rectify this situation, SDG&E agreed to contact its customers again and verify the proper allowances, correct such billing records as necessary, and refund amounts determined to have been incorrectly billed as a result of such allowances.

Resolution No. E-1833 provided for the ECAC portion of such refunds to be considered for recovery through the ECAC balancing account. This resolution also provided for the base rate portion of the refunds, together with any administrative costs, to be deferred and for recovery to be considered in a future SDG&E proceeding.

SDG&E's proposed lifeline refund plan was adopted in D.91971 of July 2, 1980, in A.59643. As a result, SDG&E refunded approximately $1.5 million to lifeline customers. Of this amount, the ECAC portion of $1,037,000 was allowed to be recovered by the company through ECAC D.91971 of July 2, 1980. The remaining $467,738 of the base rate portion, plus administrative costs of $129,017, were placed in a deferred account. These base rate amounts totaling $596,755 are requested to be considered for recovery in this proceeding.

SDG&E's witness Strachan pointed out that the reason for these lifeline refunds was the customers' failure to report to the company their ownership of appliances. The opportunity for these customers to report to the company such information, regarding electric space heating and electric water heating, was provided by bill insert questionnaires first sent to all residential customers in 1976. The second such opportunity was provided customers in March 1977, again through a bill insert seeking the same information. Simultaneously, SDG&E was pursuing an advertising campaign stressing the need for the company to have such information. Staff witness Infante acknowledged that the reason for the second set of bill inserts was the "poor" response to the first. Witness Infante accepted that SDG&E did not discover that it may have improp lifeline information until late 1978, and that the major problem was the incomplete responses provided by the customers. He agreed that the problem of incorrect lifeline allowances was the result of incomplete, inadequate information accumulated from customers' response to questionnaires and not the result of intentional wrongdoing, oversight, or miscalculation.

According to staff, the issue here is not the reasonableness of the expenditure but retroactive ratemaking. Staff states that the rule against retroactive ratemaking[3] prevents the Commission from autho ing revenues to recover any of SDG&E's expenditures made prior t effective date of the decision.

3/ William L. Govan (1926) [illegible] Cal RRC 254, 256; Southern California Water Company (1962) 59 Cal PUC 797, 799; California Cities Water Company (1967) 67 Cal PUC 197, 203; The Pacific Telephone & Telegraph Company (1968) 68 Cal PUC 203, 204.

We disagree with the staff for the following reason. Although Resolution No. E-1833 did not authorize recovery of the lifeline refunds, it did authorize the company to make those refunds to its residential customers. The company pursuant to Resolution No. E-1833 returned both the ECAC and the base rate portions of the refunds to its customers. To deny recovery of only the base rate portion to the company, as staff recommends, would be unfair.

We recognize that the prospective recovery of the refunds and associated administrative expenses incurred in 1980 will have a retroactive impact. However, we also note that the company already has made a retroactive adjustment to prior general rates by refunding the base rate portion of the lifeline refunds. Our allowance of the recovery of those expenditures merely returns to the company revenue which it collected under previously established general rates and which were recognized in a deferred account pursuant to Resolution No. E-1833. Since we approved the lifeline refund plan in Resolution No. E-1833, we will authorize recovery of the $596,755 over three years as requested by SDG&E.

C. OPERATING EXPENSES

1. Electric Production Expenses

The company stipulated to all differences with staff in this expense area (late-filed Exhibit 70). However, as company witness Stoehr noted, there was one reservation concerning the treatment of certain fuel costs associated with sales to the Department of Water Resources in excess of purchases. This is no longer an issue in the general rate case proceeding since D.92946 in Order Instituting Investigation (OII) 56, issued subsequently, determined that these costs are properly included in ECAC procedure.

During the course of the evidentiary hearing, SDG&E sought recognition of an increase in test year electric production expenses of approximately $4.9 million, allegedly caused by factors unknown at the time of its direct showing (Exhibit 58 - not admitted). The increase was for unexpected repairs and expense due to additional regulatory requirements for San Onofre Unit No. 1. The ALJ ruled that the Regulatory Lag Plan precluded introduction of this evidence. The company may seek recovery of these amounts in connection with its 1982 test year rate case.

2. Electric Transmission Expenses

a. General

The final positions of the company and staff regarding electric transmission expenses, as shown on late-filed Exhibit 70, are as follows:

SDG&E	Staff	Difference
$6,931,400	$6,793,200	$138,200

These figures (1) exclude the staff's wage adjustment which is dealt with elsewhere; (2) are conditioned upon a transfer to ECAC of wheeling charges in Account 565 in the amount of $1,512,800; and (3) include all stipulations made on the record, totaling a reduction of $204,500.

SDG&E's witness Liska explained the methodology used to develop the company's estimates. Nine years' data (1971-79) was analyzed to determine if a reasonable trend could be identified. In those cases where a trend was not indicated, a separate analysis of functionally related account groupings was performed. The company's approach considered that there is a common work force performing both operation and maintenance functions, sometimes split between gas and electric, that they do both transmission- and distribution-related work at varying times, and that their time may be charged to both capital and expense accounts. Witness Liska also noted that there was a cyclic pattern to many expenses due to the effects of rapid growth in certain years and the consequent deferral of maintenance. He stated that SDG&E developed a computerized methodology that takes into account items such as variable rates of inflation, account sensitivity to customer or system growth or both, similarity of functions between two or more closely related accounts, and other factors. The model then analyzed expenses over a long enough period of time, nine years in this case, to allow for cyclic activity.

The staff, on the other hand, analyzed individual accounts. After review of 1979 expenses as a base for estimating future costs, where no new projects, reorganizations, or unusual expenses were anticipated, staff escalated the 1979 base levels to 1981 dollars by wage and material factors. According to staff, analysis by individual accounts yielded no noninflationary growth.

SDG&E points out that the staff approach ignores the existence of a common work force and the cyclical nature of some closely related accounts. Also, SDG&E contends that analysis by individual accounts overlooks the growth rate in total expenditures.

b. Account 562 - Station Expenses-Operation
Account 570 - Station Equipment-Maintenance

The final company and staff figures, as shown in late-filed Exhibit 70 for these accounts, are as follows:

	SDG&E	Staff	Difference
Account 562	$365,300	$340,100	$25,200
Account 570	$907,300	$805,400	$101,900

Staff reviewed labor and nonlabor data for the years 1971-79 for each of these accounts and concluded that no trend was evident and that no noninflationary growth had occurred. Therefore, staff used 1979 recorded expense levels and escalated them into 1980 and 1981.

The company instead analyzed Accounts 562, 569, and 570 as a group and developed a growth rate based on recorded data for 1971 through 1979. Witness Liska explained why he chose to combine these accounts for analysis:

> "Account 570 is a closely related account to 562.
>
> "All three of them have to do with the maintenance of substation and structures and are used by the same group of substation maintenance and operations personnel regularly, so that as one account might be charged, so might the other or if one account is not particularly emphasized for a day's work, the other may be more heavily emphasized."

Witness Liska explained that the account histories were too erratic to predict future expenses if looked at individually, as staff did.

According to SDG&E, the defect in the staff's individual analysis method is that it allows for absolutely no real growth (other than inflation) in either of these accounts. A simple comparison of the data at the beginning of the trend period 1971-73, with the end of the period 1977-79, showed that the three-year average of expenses for each of these periods in fact increased from $496,109 in constant dollars. SDG&E believes this confirms that real growth occurred over the trend period, and this is not accounted for in the staff's figures.

SDG&E takes exception to staff's making no allowance for increased expenses resulting from addition of new substation facilities to serve the approximately 60,000 new customers expected in the 1979-81 period. Also, SDG&E takes exception to staff's making no allowance for the company attempting to catch up on deferred maintenance in this area.

We will adopt the company's estimates for test year 1981.

c. Account 568 - Supervision and Engineering - Maintenance

There is a difference of $11,100 in this account due to staff's exclusion of borrowed labor expenses which will support a new transmission maintenance group being formed to do hot-line work.

Staff determined that any charges for borrowed labor already had been considered and included in the recorded expenses for other operation and maintenance accounts. The company witness also stated that the historical cost for this borrowed labor was not subtracted from other accounts. As a result, inclusion of the $11,100 borrowed labor expense in Account 568 would result in a double counting of those labor charges. The staff submits that its estimate of $77,900 should be adopted to prevent a double recovery of these expenses by SDG&E.

We will adopt the staff's estimate of $77,900 for this account as reasonable for test year 1981.

3. Electric Distribution Expenses

a. General

The final positions of the company and the staff regarding electric distribution expenses, as shown in late-filed Exhibit 70, are as follows:

SDG&E	Staff	Difference
$24,776,500	$23,143,300	$1,633,200

These figures (1) exclude the staff's wage adjustment; (2) include SDG&E's corrected figures for tree-trimming expense included in Account 593 which were taken under submission by the ALJ; and (3) include all stipulations made on the record.

b. Account 593 - Maintenance of Overhead Lines

The company estimates a 1981 test year expense for Account 593 of $8,031,500 versus $7,050,200 by staff, with a difference of $981,300. This difference is attributable solely to the methodology used to develop the tree-trimming cost component of this account.

The company estimated this account as a whole, based upon an analysis of historic data. This derived an annual growth rate of 9.98 percent, which was applied to the 1979 base year figures and escalated into 1981. An adjustment of $400,000 was also made to the 1979 base year figures to reflect expansion of tree-trimming activities, which escalates to approximately $504,200 in 1981.

The staff used a five-year average of tree-trimming expense and adjusted that average for inflation.

SDG&E's figures for additional tree trimming are the corrected amounts based upon witness Liska's testimony that an honest mistake had been made as to the computer input data used to adjust the 1979 base year. Allowance of this correction was taken under submission by the ALJ.

We note that staff agrees that this was an honest mistake which was brought to the staff's attention as soon as it was discovered on August 7, 1980. Unfortunately, SDG&E neglected to inform the other interested parties. We note that the Regulatory Lag Plan does not permit updates of estimates after day 29. However, the ALJ may in his discretion permit a correction to be made for an honest mistake. Therefore, we will allow the additional amount included by SDG&E for tree-trimming expense to be considered.

The corrected estimates for tree-trimming expense for test year 1981 are:

SDG&E	Staff	Difference
$2,669,800	$1,688,500	$981,300

This issue was argued at great length. We need not repeat the testimony and are not convinced by the arguments of either the company or staff. The 1979 recorded tree-trimming expense was $1,771,222. Adjusted for inflation, this amounts to $2,143,000, and we will adopt this amount as reasonable for test year 1981.

c. Account 584 - Underground Line Expenses - Operation
Account 594 - Maintenance of Underground Lines

The company and staff positions regarding these accounts are as follows:

	SDG&E	Staff	Difference
Account 584	$480,500	$523,500	$43,000
Account 594	$3,521,000	$3,119,100	$401,900

These differences are attributable primarily to estimating methodology and the impact of the Underground Preventative Maintenance Program (UGPMP).

SDG&E's witness Liska testified that since Accounts 584 and 594 are functionally related, they were analyzed together using recorded data for the period 1971 through 1979. This analysis suggested a trended annual growth rate of almost 20 percent, which he deemed an unrealistic forecast for 1980-81. Instead, a lower fixed dollar amount of $39,000 was added to the base year 1979 figures for 1980 and 1981, and the appropriate escalations were applied. The fixed amount was derived by individual analysis of the labor and nonlabor components of the recorded data. Witness Liska felt this provided a more representative result for the future than would the 20 percent growth rate.

Staff witness Rayburn testified that he also analyzed Accounts 584 and 594 together, since they were functionally related. He trended recorded data from 1975 through 1979, excluding the UGPMP, escalated that result into 1980 and 1981, and then added back the company's estimate for the UGPMP. The staff's methodology provided a figure which was $444,900 lower than SDG&E's estimate for both accounts.

The staff reviewed SDG&E's analysis of Account 584 and found that the company projects an increase in cost per underground customer for 1980 and 1981. The company's estimate apparently does not include any allowance for increased productivity. The staff estimate, however, considers increased efficiency of operation and maintains the cost per customer near the 1979 recorded level. The staff submits that its estimate for Account 584 should be adopted since it gives the company an important incentive to increase its productivity and efficiency of operations.

Similarly, staff analyzed SDG&E's estimates of Account 594 expenses for 1980 and 1981 and found that the company projects an increase in cost per underground customer. The staff reviewed the cost per underground customer over the past five years and found a downward trend in the cost. The staff's estimate for Account 594 would continue this downward trend into 1980 and 1981. Staff expects cost savings from the company's underground preventive maintenance program to continue into 1980 and further reduce the cost per underground customer.

Staff also reviewed SDG&E's estimate for its underground preventive maintenance program, a subaccount within Account 594. Staff found the company's estimate for the program to be reasonable and allowed $972,200 for the program in 1981.

Staff submits that the expenditure for the underground preventive maintenance program should result in increased cost savings in 1981. Staff believes its estimate is more reasonable and should be adopted as it predicts a decrease in the overall cost per underground customer while the company's estimate increases the cost per customer.

SDG&E's witness Liska disagrees with the staff position that the decline in total expenses in 1979 for these two accounts was caused by the effects of the UGPMP. He stated that all of the reductions that had been experienced in Account 594 were caused by reductions in maintenance associated with capital. He said that the subaccount that allowed for the straight underground maintenance not associated with capital had actually leveled off slightly but still increased at what you might expect as inflationary levels. According to witness Liska, he does anticipate some reductions in maintenance, but certainly not in the first year of the UGPMP. He believes that the effects of the UGPMP would initially be felt in extended service lives of the system components, reduced interruptions, safety, and quality of service. He disagreed with the level of savings estimated by staff.

We believe the savings estimated by staff are high. Accordingly, we will adopt, as reasonable, the average of the staff's and SDG&E's estimates for test year 1981, i.e., Account 584 - $502,000; Account 594 - $3,320,000.

d. <u>Account 588 - Miscellaneous Distribution Expenses</u>

As shown in late-filed Exhibit 70, the company and staff estimates for this account in test year 1981 are as follows:

SDG&E	Staff	Difference
$3,338,200	$3,131,200	$207,000

The sole issue here regards the company's request for the addition of "four automated drafting work-stations and drafters who will begin reducing the 2,500 man-day mapping backlog, and be available to begin converting present records and maps into the DFIS data base."

SDG&E's witness Liska explained that a backlog in preparing distribution system maps has developed in recent years since (1) the current process requires that the maps be updated manually; (2) the underground facilities mapping requires more detail; and (3) the number of new underground customers has exceeded the estimates and available manpower. The four-person team would attempt to catch up and avoid a compounding of the problem which has developed.

Staff derived a five-year growth rate for Account 588 which it claims should account for increased expenses in 1981. Staff maintains that the company has functioned in the past with a backlog and can continue to operate in 1981. It is staff's position that the backlog can be reduced when the new Distribution Facilities Information System (DFIS) is fully implemented. Staff also expects the DFIS program to offset any future needs for additional personnel since implementation of the DFIS program has been accelerated from an eight-year to a five-year schedule.

Staff submits that an increase in mapping equipment and personnel just before a new electric mapping system is installed is unnecessary and wasteful.

We disagree with the staff position that the company should continue to operate with a backlog through 1981 and will adopt the company's estimate of $3,338,200 as reasonable for test year 1981.

4. Gas Supply Expenses, Gas Storage Expenses, and Gas Transmission Expenses

There is no basic disagreement between the company and staff regarding these gas accounts. However, late-filed Exhibit 70 shows there is a remaining difference in Accounts 810 and 812, which are credits to gas supply expense. There are also differences in Gas Storage Account 841, and Gas Transmission Account 854.

Account 810 is a credit account for compressor fuel expenses debited to Accounts 841 and 854, and the differences are offsetting. Account 812 is a credit account for gas purchased by other company departments.

In addition, the company's final estimates reflect the effect of the actual July 1980 increase in the rate paid to Southern California Gas Company under Schedule G-61. The staff's figures would correspond with the company's if this change were also made in their showing (late-filed Exhibit 70).

5. Gas Distribution Expenses

a. General

SDG&E stipulated to all of the staff's estimates of gas distribution expenses, except for Accounts 880, 887, and 892. As shown in late-filed Exhibit 70, the relative company and staff positions for these accounts are as follows:

	SDG&E	Staff	Difference
Account 880	$ 849,500	$ 749,400	$ 55,100
Account 887	1,521,000	1,413,400	107,600
Account 892	548,900	420,600	128,300
Total			$291,000

SDG&E's witness Rogers indicated that with respect to the stipulated accounts, the staff's estimates were an adequate reflection of the general level of anticipated test year expenses. He stated that his conclusions were based upon an independent evaluation which he performed using more current data and his methodology. He did not purport to endorse the staff's methodology in making his stipulations.

The remaining differences are significant and are attributable primarily to the forecasting methodology. SDG&E analyzed recorded data from 1971 to 1979, looking at activities and influences which were causally responsible for "trends".

Labor hours and nonlabor dollars were separated. A regression analysis was performed and a trend developed which provided the best "fit" for the test year data points. These figures (labor hours and nonlabor dollars) were then escalated into 1980 and 1981, using the corporate inflation assumptions (which are the same as staff's).

The staff's estimates are based on recorded expenditures for the first half of 1980. A seasonal factor was developed for each account individually, based on an analysis of the first six months' recorded data, for the period 1975 to 1979. The six-month seasonal factors for each year were then averaged. As shown in Exhibit 31, the resulting factor was then applied to recorded expenses for the first six months of 1980, to develop the expected expenses for the remainder of the year. The 1980 figure was split into labor and nonlabor using a labor factor, and then escalated into 1981.

According to SDG&E, the problem with the staff's approach is that it totally ignores the possibility that the six months' 1980 data may not be representative of the future. It also presumes that the percent of expenses following in the second half of 1980 will be accurately estimated by the average percent of total yearly expense falling in the second half of the year over the period 1975 to 1979. SDG&E contends that other than labor hour adjustments for planned organization changes, staff's method provides for no growth in activity between 1980 and 1981, since only the escalation rates are used.

b. Account 880 - Other Expenses

We find that the staff use of an average seasonal factor overlooks the trend since 1977 and produces a test year estimate which is lower than if the latest recorded factor was used. On the other hand, SDG&E's estimate for the test year is high compared to recent recorded. We will adopt the average of SDG&E's and the staff's estimate of $822,000 as reasonable for test year 1981.

c. Account 887 - Maintenance of Mains

There is a difference of $107,600 in this account, again due to methodology. The company made its estimate as described previously in this section, as did staff.

According to SDG&E, staff made no attempt to evaluate whether 1979 was representative of prior years in developing its labor factor to split out the 1980 extrapolated results. Also, SDG&E contends that staff failed to investigate whether other factors might have impacted this account, such as abnormal weather, and the effect of a common labor pool which charges expense to both distribution and transmission, as well as gas and electric accounts.

SDG&E's witness Rogers testified that figures for the first half of 1980 did not reflect the anticipated expenses associated with a welding school which is charged to Account 887. According to witness Rogers, expenses in the last half of 1980 are expected to increase, making the whole of 1980 more normal, which effect will continue into 1981. He believes that the staff's use of the first six months of 1980 recorded data as its starting point, which is too low, cannot yield a representative estimate for test year expenses. We agree with SDG&E and will adopt the company's expense of $1,521,000 as reasonable for test year 1981.

d. Account 892 - Maintenance of Services

There remains a difference between the company and staff in Account 892 of $128,300, as shown in late-filed Exhibit 70. For the same reasons discussed in Account 887, we will adopt SDG&E's estimate of $548,900 as reasonable for test year 1981.

6. Customer Accounting and Collection Expenses

a. General

In the area of customer accounting and collection expenses for both the Gas and Electric Departments, the difference between the company and staff (excluding Account 904, Uncollectible Accounts, and the wage adjustment) is as follows:

SDG&E	Staff	Difference
$13,094,500	$12,471,500	$623,000

The differences lie in the areas of Account 903.2, Credit Management; Account 903.3, Collections; Account 903.5, Billing and Bookkeeping; and Account 903.7, Postage.

b. Account 903.7 - Postage

The difference between staff and the company in this subaccount for both the Gas and Electric Departments is as follows:

SDG&E	Staff	Difference
$1,953,200	$1,517,600	$435,600

SDG&E's request is based upon an application filed by the postal service to increase presort postage rates from 13 cents to 17 cents. A decision by the Postal Rate Commission on the application is not expected until the end of February 1981. Thus, a postage rate increase will not be authorized by the Postal Rate Commission before the Commission issues its decision for this proceeding.

Staff submits that the mere submittal by the postal service of an application to the Postal Rate Commission does not justify authorization of increased expenses to SDG&E in 1981.

We agree with staff. We will adopt the staff estimate of $1,517,600 as reasonable for test year 1981.

c. Account 903.2 - Credit Management
Account 903.3 - Collections
<u>Account 903.5 - Billing and Bookkeeping</u>

The total difference between the company and staff in these three subaccounts for the Electric Department is as follows:

SDG&E	Staff	Difference
$2,078,800	$1,891,400	$187,400

The staff methodology in developing its cost estimates for these subaccounts was to trend the historical costs per customer for the years 1975 through 1979. Staff attributed the decline in these accounts to improved productivity, better labor management, and cost savings.

The company's methodology for estimating these subaccounts was to divide the previous year's (1979) costs for each such account by the average number of customers during that period to develop the average cost per customer. This was then multiplied by the average annual expected customers for 12 months ended December 31, 1981, in order to derive an estimated 1981 expense prior to any adjustment for wages or postage. The labor portion of that total was then escalated for the expected wage increase in 1981. The remaining nonlabor portion has no adjustment for inflation.

SDG&E's witness Ault pointed out that, historically, the company's methodology, which does not inflate the nonlabor portion of the estimated expenses, develops a differential which is approximately equal to the increase in productivity that the company experiences. Therefore, according to witness Ault, the company's methodology does, in fact, take into consideration increased productivity.

Staff witness Chan concluded that the company's reliance only on nonlabor portions of the accounts, which were less than 20 percent for all three subaccounts, could not adequately reflect increased productivity occurring in the entire account.

According to witness Chan, SDG&E's cost per customer for customer account service has declined since 1976. The staff estimates continue this downward trend to project a cost per customer of $11.72 in 1981. On the other hand, the company's projected cost per customer of $12.04 in 1981 is an increase above the recorded 1979 level.

Staff submits that its estimates fully capture the impact of increased productivity in 1981. Acceptance of the SDG&E's figures in this area would underestimate the impact of increased productivity and could undercut the company's economic incentive for efficient operations in 1981.

SDG&E's witness Ault testified that examination of recorded costs for the first seven months of 1980, annualized to develop 12-month figures for 1980, compared with the staff's estimates for 1981, showed increases of 2.9, 2.5, and 6.6 percent, respectively, for the three subaccounts. Witness Ault considered this to be inadequate since the wage increase expected for 1981 was 13.5 percent.

According to witness Ault, in these times of more complex billing and bookkeeping practices it is reasonable to expect these expenses to increase. Furthermore, these accounts address credit management and collections which necessitate additional costs in these poor economic times with increasing bankruptcies. Witness Ault contends that the staff method which develops 1981 estimates by strictly looking at recorded data is not appropriate as it does not realistically consider recent developments and anticipated costs for 1981.

On further scrutiny of the company's estimate, based on witness Ault's testimony, we find that the company's figures for the three subaccounts in total cover approximately half of the wage increase for 1981 assuming no change in the number of employees. In other words, the company will have to offset half the wage increase with increased productivity. We think this is a reasonable offset for increased productivity. We will adopt the company's estimate for test year 1981. The adopted expenditures for the Electric Department are:

Account 903.2	$ 144,500
Account 903.3	1,056,000
Account 903.5	878,300
Total	$2,078,800

7. Marketing Expenses

The following tabulation shows marketing expenses adopted for conservation programs for test year 1981. For details see discussion on conservation, Chapter VIII.

Table VIII

ted Marketing Expenses
Test Year 1981

Account No.	Electric	Gas	Total
	(Thousands of Dollars)		
907	$ 171.0	$ 93.0	$ 264.0
908	5,678.0	2,378.0	8,056.0
909	463.0	168.0	631.0
910	373.0	249.0	622.0
Tot. Marketing Exp.	$6,685.0	$2,888.0	$ 9,573.0
920		School Program	169.0
		Conservation Programs Expensed	9,742.0
		CVR Program Capitalized	1,597.0
		Total Conservation Programs	$11,339.0

8. Administrative and General (A&G) Expenses

a. General

The difference between the company and staff for both the Gas and Electric Departments, excluding Account 927, Franchise Fees, and the wage adjustment, is as follows:

SDG&E	Staff	Difference
$55,142,100	$53,651,800	$1,490,300

This difference arises in Account 922, A&G Transferred-Credit; Account 926, Employee Pensions and Benefits (Employee Organizations and Newsmeter); Account 930, Miscellaneous General Expenses (Research and Development (R&D) Blanket and Stock and Bond Expense); Account 931, Rents; and Account 932, Maintenance of General Plant.

b. Account 922 - A&G Transferred-Credit

The difference between staff and the company in Account 922 for both gas and electric is as follows:

SDG&E	Staff	Difference
$-11,193,600	$-12,204,900	$1,011,300

The difference in this account is due to the use of different capitalization ratios by the company and staff. The company used a ratio of 22 percent while staff used a ratio of 26 percent.

Account 922 reflects the transfer to construction of a certain portion of the company's employee benefits and a certain portion of the expenses incurred in Accounts 920 and 921. The transfer establishes a credit to Account 922. The company and staff agree on the allocation of employee benefits to construction. However, the company does take exception with the allocation percentage used by staff.

SDG&E's witness Ault stated that the company annually prepares a study which determines the amount of dollars appropriately charged to Accounts 920 and 921, which are related to construction accounts with the corresponding credit being recorded in Account 922. The company's capitalization rate is developed by a two-step process: First, the expected construction activity for the test year is examined; second, a comparison is made between that estimate and historical percentages for years with a level of construction activity expected to be similar to the test year. Historical rates since 1975 have been as follows:

Year	Rate
1975	25%
1976	24%
1977	23%
1978	26%
1979	28%
1980 (est.)	25%

SDG&E points out that in 1975 when the rate was higher, the company was in the process of constructing its Encina 4 generating station. Furthermore, in 1978 and 1979 the company's Encina 5 generating station was under construction. In 1981 SDG&E will have no major power plants under construction.

The staff witness computed an average capitalization ratio of the recorded numbers from 1975 to 1979 and a 1980 as-expected figure and also developed a least squares trend from those numbers. He then took the midpoint between the average of 25 percent and the trended figure of 27 percent to derive his capitalization ratio of 26 percent for the 1981 test year.

Witness Ault stated the company's estimate also took into consideration the fact that the overall construction level related to new customers is decreasing. That is, instead of adding customers at the rate that was experienced between 1975 through 1979, that rate has shown a decline in 1980 which is expected to continue. He further stated that the company's reduced level of construction activity is demonstrated by the fact that the company is now in the process of closing its Plant Construction Department in order to allow for greater utilization of outside contracting services.

Taking all of these considerations into account, SDG&E concluded that 1977, with its rate of 23 percent, was a comparable year to 1981 due to the fact that no power plants were under construction during that time frame. Further, witness Ault felt that a 1 percent reduction to 22 percent would be appropriate to reflect the reduced rate of growth in new customers.

We believe an average of the company's and staff's estimate will be reasonable and adopt 24 percent as the capitalization ratio for test year 1981.

c. Account 926 - Employee Pension and Benefits, Newsmeter, and Employee Organizations

Account 926 contains the costs of the company news periodical to employees, the Newsmeter. The total difference between the company and staff attributable to this periodical is $114,000 for both the Gas and Electric Departments. Also, in Account 926 are the costs of company Employee Organizations. The difference between the company and staff in this category is $74,500 for both the Gas and Electric Departments.

Examples of expenses which would be included in the category of Employee Organizations are the costs of supporting the Old Timers' Annual Banquet to honor retired employees or those with length of time in service to the company over a certain minimum. Furthermore, these expenses sponsor such functions as the Christmas Dinner for the Employee Women's Committee.

The staff's position is that the Newsmeter does not produce any measurable benefits for the ratepayer in terms of increased operating efficiency or greater employee productivity. Staff points out that SDG&E, for a variety of reasons, is a financially troubled utility that already charges electric rates that are among the highest in the country. SDG&E's ratepayers, who already are confronted with high utility bills, should not be forced to subsidize activities which, according to staff, have a speculative impact, if any, on the company's service and operations. Accordingly, staff recommends disallowance of these expenditures.

The above items may be reasonable business expenditures serving worthwhile purposes, but they suggest that SDG&E may not sufficiently recognize the need for tightening its corporate belt and sharing with its ratepayers the burden of increasing energy costs. We will not adopt staff's recommendations to disallow these expenditures for test year 1981, but we commend the staff's efforts and encourage further close analysis of SDG&E's operating expenses for the 1982 test year proceeding. We intend to apply a more rigorous standard in assessing the reasonableness of such marginally necessary expenses in that proceeding.

d. Account 930 - Miscellaneous General Expenses-
R&D Blanket

SDG&E is requesting a R&D blanket in the amount of $300,000. Staff recommends disallowance of this amount. With this exception, SDG&E and staff are in agreement on R&D programs for test year 1981.

According to SDG&E, the purpose of the blanket is to cover the cost of unanticipated R&D projects which are worthwhile. SDG&E's witness Ault pointed out that frequently such projects present themselves and funds would not have been provided in rates. The blanket will enable the company to pursue such programs without cutting funds committed to existing projects. The company is seeking the flexibility, through the blanket, which will enable it to achieve its R&D goals for the benefit of the ratepayer.

SDG&E's witness Ault feels confident that at this point in time the 1981 blanket will be spent in the area of solar or geothermal, not including the Heber Project. The intended scope for these R&D efforts is in developing resources indigenous to SDG&E's service territory, i.e., solar, geothermal, conservation, etc.

Witness Ault testified that the company's 1980 blanket ($664,000) was used in the areas of geothermal, solar, biomass, or energy conservation as specified by the Commission in D.90405. Specifically, the blanket was used for the Heber Project and the geothermal project at East Mesa. Consistent with D.91271, the company has used a large portion of the blanket on the Heber Geothermal Project. None of the $300,000 blanket requested in this proceeding is for Heber.

Staff witness Joshin recommended disallowing the general research blanket for several reasons: (1) authorization of a general research blanket would eliminate any opportunity for prior staff review of projects funded under a general research blanket; (2) the Regulatory Lag Plan gives the utility sufficient time to submit complete estimates of R&D programs for the upcoming test year; and (3) authorization of a general research blanket creates an unwarranted "cushion" which allows the utility to recover in rates more than its projected R&D expenses for the test year.

Furthermore, staff maintains that SDG&E did not use the $664,000 blanket, allowed in D.90405 for test year 1979, in the specified manner. Staff points out that in D.90405, page 42a, the Commission authorized a general research blanket on the condition that the funds be used for R&D in the areas of geothermal, solar, biomass, or energy conservation. However, SDG&E used blanket funds in 1979 on two projects, Fuel Oil Additive and DFIS - Phase II, which did not fall within the Commission's prescribed guidelines. As a result, the staff witness recommends that the requested $300,000 blanket be disallowed for the 1981 test year to prevent additional R&D expenditures by SDG&E on programs that are not approved for blanket funding.

We note that the total R&D expense for test year 1981 exceeds $10 million (see discussion in Chapter IX), and we believe this amount provides SDG&E with the flexibility to rearrange its R&D priorities. We will adopt staff's recommendation and disallow SDG&E's request for a $300,000 R&D blanket.

e. Account 930 - Miscellaneous General Expenses-
<u>Stock and Bond Expense</u>

The difference between the company and staff in the area of stock and bond expenses for both the Gas and Electric Departments is as follows:

SDG&E	Staff	Difference
$761,300	$726,400	$34,900

Staff used a least squares trend from 1975 through 1979 to project expenses for 1981. According to SDG&E, staff's 1981 estimate does not take into account the issuance of more debt and equity in 1981 than was issued in 1979, and 1979 was a year of abnormally high-recorded stock and bond expenses.

Staff submits that its estimate of $726,400 for the cost of stock and debt issuance in 1981 is a reasonable increase over the 1979 recorded level of $629,206 since its figure represents a 15 percent increase from the 1979 level for Subaccount 930.220.

We will adopt the staff's estimate of $726,400 as reasonable for test year 1981.

f. <u>Account 931 - Rents</u>

The total difference between the company and staff in this account for both the Gas and Electric Departments is as follows:

SDG&E	Staff	Difference
$1,146,900	$1,064,600	$82,300

The difference relates to the amount of rent for lease of the electric building.

According to SDG&E, the company's rent on the electric building is fixed for the term of the lease and the company estimates its 1981 expense to be the same as the 1979 level.

Staff used a least squares trend of the amount of electric building rent charged to Account 931 from 1975 through 1979 to derive its 1981 estimate. Staff shows a decrease in the amount of electric building rent allocated to this expense account as compared to 1979 recorded.

We will adopt SDG&E's estimate of $1,146,900 as being reasonable for test year 1981.

g. Account 932 - Maintenance of General Plant

The difference between the company and staff for both the Gas and Electric Departments is as follows:

SDG&E	Staff	Difference
$1,716,500	$1,581,400	$135,100

The company's 1981 estimate was developed by taking the 1979 recorded level of expenditures and escalating that amount for labor and nonlabor inflation. According to SDG&E, this methodology properly reflects the higher level of recorded expense in 1979 which captures the company's expanded maintenance program.

Staff used a five-year trend to develop the 1981 test year estimate. SDG&E submits that the staff methodology does not reflect the company's augmented plant maintenance program as it was pursued in 1979, and for this reason the staff's estimate is unreasonably low.

The staff witness observed that 1979 was an abnormally high-recorded year which increased by 42 percent from 1978. Prior recorded increases averaged 4 percent or less. According to staff, the company's reliance on the 1979 level as a base which is then escalated to a 1981 level exaggerates the level of expenses for general plant maintenance which will be experienced in 1981.

We believe an average of the company's and staff's estimate will provide SDG&E with a sufficiently augmented maintenance program for 1981. Accordingly, we adopt $1,649,000 as a reasonable level of expenditure for test year 1981.

9. Depreciation and Amortization

SDG&E and staff agree on the proper depreciation rates to be utilized and the appropriate methodology to be employed. We will use the same rates and methodology in our adopted results.

10. Ad Valorem Taxes

The difference between SDG&E and staff in the area of ad valorem taxes is in the amount of $1,895,000 for both the Gas and Electric Departments.

Staff and the company used substantially different methodologies in allocating ad valorem taxes between capital and expense. Staff witness Bondeson pointed out that he had made an identical recommendation for allocating ad valorem taxes in Edison's pending A.59351. SDG&E's witness Strachan testified that because the issues are the same in this proceeding as in the Edison case and because under the staff methodology the total tax expense would be substantially the same, SDG&E would be willing to accept whatever resolution of this particular issue is made in the pending Edison case. We will adopt the staff's estimate.

11. Payroll and Miscellaneous Taxes

No differences exist between the company and staff in the payroll and miscellaneous tax expense category.

12. Income Taxes

a. General

There are differences between the company and staff in income tax expense in three areas: (1) benefit costs capitalized; (2) R&D expense (Heber); and (3) investment tax credit (ITC) carry-overs. These differences are in the treatment of book-to-tax (Schedule M) deductions which impact taxable income. The staff's results of operation report, Exhibit 14 (Electric) and Exhibit 15 (Gas), Tables 14-C and 15-C, respectively, identify the Schedule M deductions.

In the following tabulation it will be noted that staff shows larger Schedule M deductions. This results in lower income tax expense for the company.

b. Benefit Costs Capitalized

The company and staff Schedule M deductions are as follows:

	Staff	SDG&E	Difference
Electric	$9,629,000	$7,448,000	$2,181,000
Gas	3,158,000	1,857,000	1,301,000
Total			$3,482,000

The benefits capitalized Schedule M adjustment is intended to recognize that certain expenditures which are normally capitalized on the company's books can be taken as current expense deductions for income tax purposes. This item reflects the effects of certain administrative and general expenses, pensions and benefits, and payroll taxes which are capitalized for book purposes and therefore do not show up in the results of operations as expenses, but are nonetheless deductible for tax purposes.

Staff witness Mulligan stated that the primary reason for the difference between the company and staff is that staff included health and dental costs in the Schedule M adjustment, whereas the company did not. By making the additional Schedule M adjustment for health and dental costs, staff has imputed the existence of a current deduction that the company is not taking on its tax return. These costs are capitalized for tax purposes by the company. The company cannot automatically take this item as a deduction, since it must request and receive permission from the Internal Revenue Service (IRS) to adjust its tax accounting.

According to staff, Income Tax Ruling 3408 attached to Exhibit 29 allows health and dental costs as proper deductions even though a portion of those items may be capitalized and charged to construction. Staff agrees that Income Tax Ruling 3408 presently is under review by the national office of the IRS and may be revoked. However, it is staff's position that Income Tax Ruling 3408 has not yet been rescinded and may be relied upon by a taxpayer. Staff points out that the IRS in a letter ruling dated July 26, 1979 stated that although Income Tax Ruling 3408 is under review, the ruling is still in effect and shall be observed until the ruling is actually withdrawn.

SDG&E's witness Fonss stated it would not be prudent for the company to take this additional deduction under any circumstances, due to the existence of substantial amounts of unused ITC which could expire in future years. He further explained that he had a responsibility to both the ratepayers and the company's shareholders to manage its tax strategy to everyone's best interest. Witness Fonss stated that neither the company nor its ratepayers need any more current deductions. Moreover, if the Commission allows the company to continue to capitalize the health and dental plan costs, there will be a better matching of tax benefits with expenses charged to the ratepayer. The same ratepayer who will be paying for the plant asset in the future will also benefit from the additional depreciation for tax purposes which will be available under the company's method. According to witness Fonss, under the staff's proposal, on the other hand, the current ratepayer will benefit from the tax deduction and he may never bear any part of the cost of the asset to which the underlying expenditure is related.

Both witnesses Fonss and Mulligan stated that the IRS is contemplating retracting Income Tax Ruling 3408, which would eliminate any possibility of these costs being currently deductible.

Regarding the question of how the company can be made whole for any revenue shortfall if IRS should subsequently disallow the deduction, staff suggests that the Commission could determine not to flow through the accelerated depreciation and 4 percent ITC arising from the health and dental costs in future test years. In this way, the company could recoup any unrecognized tax expense in 1981 by retaining in future years the depreciation and ITC tax benefits attributable to capitalization of its health and dental costs.

We do not agree with staff's suggestion for recouping unrecognized tax expense and will adopt the company's Schedule M deduction of $7,448,000 as reasonable for test year 1981.

c. <u>R&D Expense (Heber)</u>

Another major difference between the company and staff relates to the Schedule M adjustment for the Heber Binary Project. As testified to by SDG&E's witness Fonss in Exhibit 34, the company seeks to include a negative adjustment of $2,791,000 (revised) for the Electric Department, and staff has included no adjustment.

The company's position is premised on the fact that the Heber expenditures during the test year are not currently deductible for tax return purposes and, without an adjustment, the revenue received from the ratepayer would be fully taxable. Staff contends, on the other hand, that the expenditures would be currently deductible and that no adjustment is necessary.

This issue originally surfaced in the Heber A.59280 and was deferred to this proceeding by the Commission in D.91271. Ordering Paragraph 12 of that decision provided:

> "12. SDG&E and the Commission staff are directed to address the income tax expense consequences resulting from this project in SDG&E's next general rate proceeding to insure the utility will not recover more than <u>dollar for dollar</u> for the R&D project authorized herein." (Emphasis added.)

SDG&E contends that without the Schedule M adjustment as proposed, it will not, in fact, be reimbursed on a dollar-for-dollar basis, since each dollar received from the ratepayer as an R&D expense would be subject to taxation. According to SDG&E, this result would be contrary to the Commission's intent to provide full reimbursement of Heber-related expenses, as well as a current cash flow for the project expenditures.

There is a difference of opinion as to the correct interpretation of the applicable provisions of the Internal Revenue Code (Code) and the regulations thereunder. Staff contends that all of the Heber Project expenditures qualify for current deductibility under Section 174 of the Code. The company, on the other hand, contends that Section 174 explicitly precludes current deductibility, and that the expenditures must be capitalized and depreciated over the life of the project, just as with any other power plant project.

Staff witness Mulligan stated that based on his reading of the Heber record and decision, the project qualified for an immediate deduction under IRS Regulation 1.174-2(a)(1). That regulation provides: "The term 'research or experimental expenditures', as used in section 174, means expenditures incurred in connection with the taxpayer's trade or business which represent research and development costs in the experimental or laboratory sense."

According to staff, a review of the Heber record, A.59280, shows that the company witness' assumptions about the Heber Project's eventual availability for commercial use are unfounded. Staff refers to SDG&E's witness Gary Cotton's testimony in A.59280 that states:

> "Given a successful outcome of a demonstration program, plant operation <u>may</u> be continued on a commercial basis." (Emphasis added.) (Vol. 1, RT 14 in A.59280.)

> "The purpose of the project is to demonstrate a new cycle that has not been demonstrated at a commercial size, and for that reason we consider the total project to be an R&D program." (Vol. 1, RT 32.)

> "After the demonstration period it would be normal for us to take the plant and try to integrate it into our system of resources as a commercial plant, although, we are <u>not including it in our resource plan</u>." (Emphasis added.) (Vol. 1, RT 48.)

> "Primarily it will be, operated as a demonstration plant, and the power that it produces from the standpoint of being usable to the customers, and so forth, is probably of questionable value." (Vol. 1, RT 60.)

SDG&E strongly disagrees with the staff's position that the Heber Project is R&D in the experimental or laboratory sense.

SDG&E points out that throughout the Heber proceeding, the company described the objective of the project to be the demonstration of the commercial scale feasibility of the binary cycle geothermal technology (A.59280, RT 14-5). It was always contemplated that the plant facility would continue to operate after the demonstration phase on a commercial basis. The heat supply contract will be negotiated to provide for a 30-year term (A.59280, RT 24); the cost of electricity generated by the plant was openly discussed (A.59280, RT 244-5); arrangements to reimburse the Department of Energy when the plant becomes commercial were explored (A.59280, RT 80-82); and possible ECAC treatment of the cost of geothermal brine was contemplated (A.59280, RT 59-60). The company specifically stated that it has a goal of 80 percent availability for the plant (A.59280, RT 68-9); that there was a very low probability of failure (A.59280, RT 32); and that the plant components will be designed with a 30-year life in mind (A.59280, RT 82). According to SDG&E, the company's intention in this regard was best expressed by Mr. Cotton in A.59280 where he stated:

> "A. Well, if you are going to build a commercial size demonstration plant at the size of the dollars that we are dealing with in order to do that, first of all you want the plant to be a success. You are not building a demonstration plant to be a failure. You are building it to be a success and prove the objectives we have outlined.
>
> "On that basis it would be kind of ridiculous for us to build a plant to operate for five years.
>
> "Say we demonstrate it now and walk away from it.
>
> "After the demonstration period it would be normal for us to take the plant and try to integrate it into our system of resources as a commercial plant, although we are not including it in our resource plant."

We believe the future of the Heber Project as a commercial plant is unknown at this time. As we view it, at this point in time the Heber Project is a demonstration of the commercial feasibility or the commercial infeasibility of the geothermal binary process. SDG&E hopes that the Heber Project eventually will have commercial value, but for the moment the Heber Project must be considered only as an R&D program for ratemaking purposes.

The Commission explicitly recognized in D 91271 (page 48) that the Heber Project construction and demonstration costs should be treated as R&D expenses for ratemaking. The Commission allowed SDG&E to expense rather than capitalize its share of the Heber Project. As a result, the current ratepayer is forced to pay for the cost of the Heber Project before it is operational. Staff contends that SDG&E should also be required to currently deduct the Heber Project costs so that the present ratepayer also will receive any tax benefits that may accrue from the project. Otherwise, the present ratepayer would bear the entire expense of the Heber Project while the future ratepayer would receive the benefits of any tax deductions as well as any other benefits when the project becomes operational. Staff points out that if the Commission recognizes for ratemaking purposes that the Heber Project expenses are currently deductible, then at least the tax benefits attributable to the Heber Project will be flowed through to the present ratepayer who is paying for the entire project.

According to staff, if the IRS should disallow a current deduction of the Heber Project costs under Section 174, then SDG&E will be required to capitalize only the expenditures for the actual physical plant constructed for the Heber Project. Furthermore, if a Section 174 current deduction is disallowed, then SDG&E's 1981 income tax expense should not be materially affected due to the availability of a $14.7 million net operating loss (NOL) carry-over and unused ITC of about $41 million. Because of these offsetting deductions and credits, SDG&E will not be subject to any actual reduction in revenue; (however, we expect there will be an effect on the NOL carry-over.)

There is another aspect of this matter which we should touch upon. If the entire project is expensed, then there will be no future tax depreciation offsets. We believe this is reasonable since this will benefit present ratepayers who are paying for the project.

SDG&E points out that Regulation 1.174-2(b)(1) explicitly precludes this project from qualifying under Section 174 of the Code, even if it is R&D in a laboratory sense. The regulation provides:

> "Expenditures by the taxpayer for the acquisition or improvement of land, or for the acquisition or improvement of property which is subject to an allowance for depreciation under section 167 or depletion under section 611, are not deductible under section 174, irrespective of the fact that the property or improvements may be used by the taxpayer in connection with research or experimentation." (Exhibit 35.) (Emphasis added.)

SDG&E submits that in view of the company's intent to construct Heber so that it can operate on a commercial basis, the project will result in "the acquisition of property that is subject to an allowance for depreciation under Section 167 of the Code" (RT 1548); that is, the end result will be a 45-megawatt geothermal power plant which will be depreciated for tax purposes like any other plant facility over its useful life.

Staff contends that SDG&E should take this tax deduction on its return and aggressively argue its appropriateness with the IRS. Witness Mulligan indicated that if after audit by the IRS, which could be years from now, it is determined that the deduction is inappropriate and that there is an additional tax liability, the ratepayers should make the company whole.

On the other hand, SDG&E points out that there may be some legal and procedural complications with the staff's suggestions. SDG&E submits that the more prudent approach would be to allow the additional tax expense in test year 1981, subject to refund, with the proviso that SDG&E seek a revenue ruling on its interpretation of the Code.

In the Heber D.91271 we ordered:

"4. Commencing January 1, 1981, and annually thereafter, SDG&E is authorized to file an application or advice letter to obtain rates which would allow the receipt of revenues to cover reasonable project costs during the current year. If such request is part of a pending general rate case, the Commission may consider issuing an interim decision regarding that matter as of January 1 of each year."

* * *

"6. To account for project expenditures and revenues received during each calendar year, SDG&E is authorized to establish a Heber project balancing account, commencing January 1, 1981."

In view of the establishment of a balancing account commencing January 1, 1981, we believe SDG&E's fears are unfounded that it may not be able to recover income tax expense if none is allowed in this proceeding (because of the rule against retroactive ratemaking). Further, since the record is clear that because of large ITC credits SDG&E will not be paying income tax in 1981, we believe there is ample time for SDG&E to seek an IRS ruling.

We should remind SDG&E that the Heber Project was given special ratemaking treatment in D.91271 and it was made clear that the company would not recover more than dollar for dollar for the project. Accordingly, we will not allow SDG&E's Schedule M adjustment of $2,791,000 for test year 1981. We will review the question of income tax expense for the Heber Project in subsequent proceedings.

d. ITC Carry-overs

The third area of dispute between the company and staff regarding income taxes is whether ITC normalized carry-overs[4/] should be reflected in the test year. The figures are as follows:

	Staff	SDG&E	Difference
Electric	$(722,000)	$ (98,000)	$(624,000)
Gas	(77,000)	(14,000)	(63,000)
Total	$(799,000)	$(112,000)	$(687,000)

Staff and company agree that the current year 1981 ITC should be flowed through. However, staff has proposed to further reduce test year income tax expense by the ratable portion of the unused additional 6 percent investment tax credits which were generated during the period 1975 to 1979, to the extent they have not been flowed through in prior rate decisions. There are approximately $30 million of these credits available, of which $687,000 is proposed to be flowed through in the test year. This amount will grow in future test years as new plant is added.

The company submits that it is improper to flow through the benefit of prior years' ITC if, in fact, those credits have not been utilized on the tax return. The primary reason these credits have gone unused is that, in all but one of the last six years, SDG&E did not have any taxable income. This was caused by a shortfall in revenue or an increase in expenses for those years, compared to the levels assumed in their respective test years.

4/ As differentiated from flow-through ITC credits.

SDG&E's position, as expressed by witness Fonss, is that these credits should be flowed through to the ratepayer only after the company, in fact, utilizes them on its tax return. According to SDG&E, if the staff position is followed, the ratepayer may receive a benefit which the company may never itself realize. Witness Fonss testified that almost $3 million of credits must be used by 1981 or they will expire due to the time limitation on their use.

The staff's position is that flow-through of all ITC normalized should be adopted by the Commission for several reasons: (1) the Commission sets rates and considers income tax expense on a test year basis which is not related to the actual income tax paid by the utility in the test year; (2) the Commission does not consider "real world" taxes in a general rate case (rather, the Commission evaluates income tax liability and benefits attributable to the utility operations in the test year and derives a ratemaking estimate of tax expense for the test year); (3) the staff's recommendation follows traditional ratemaking policy by simply flowing through the benefits of any ITC generated in prior years attributable to construction of utility plant which has not been flowed through because of the company's Section 46(f)(2) election; and (4) the flow-through of these ITC benefits is in conformance with the Commission's stated policy for all major utilities.

Staff points out that to argue, as the utility does, that a flow-through should not be recognized unless the ITC will actually be utilized in the test year is to advocate recognition of actual or "real world" taxes. Calculation of income tax expense on an "income taxes actually paid" basis is an issue in OII 24.

Staff submits that if the Commission nevertheless should decide that a flow-through only of ITC actually utilized in the 1981 test year is appropriate in this case, then to be consistent the Commission must determine what SDG&E's actual income tax liability will be in 1981 and set rates on a "taxes as paid" basis. Staff would agree to such a calculation of actual income tax expense but suggests that use of actual income taxes would be inappropriate before OII 24 is resolved. It is the staff's position that until OII 24 is decided, the Commission should adhere to its traditional method for calculating income tax expense in this proceeding and flow through all ITC normalized whether or not SDG&E actually will be able to utilize all of those credits in 1981.

According to staff, if the Commission declined to flow through ITC normalized as recommended by staff, the company nevertheless may earn enough taxable income in 1981 to utilize ITC which the Commission did not recognize when fixing rates. In that event, the company would receive all the benefit from applying those credits against its tax expense. The tax benefits already realized by the company could not be transferred to the ratepayer in a future test year due to the rule against retroactive ratemaking. As a result, staff points out, the company would reap an undeserved windfall because the Commission failed to flow through the ITC as quickly as possible.

We will adopt the staff's estimate as reasonable for test year 1981, since this reflects traditional ratemaking policy.

13. Wage Settlement

A major area of difference between the company and staff is the wage rate assumption to be used for test year 1981. SDG&E's witness Williams testified that the company's assumption used throughout the results of operation reports was a wage increase of 13.5 percent, commencing March 1, 1981. He explained that the company has offered its union an increase in 1981 which will track the rise in the Consumer Price Index (CPI) for 1980, with an upper limit of 13.5 percent. The percent increase will be determined by comparing the December 1979 CPI with the December 1980 CPI.

Staff has included, throughout its results of operation exhibits, a wage adjustment showing the effect of an increase of only 11 percent in 1981.

While we cannot ignore valid costs that a utility is incurring in providing service to its customers, we must examine closely costs such as labor for reasonableness for the simple fact that the utility is incurring them may not of itself be sufficient justification of reasonableness. We do not wish to establish the precedent of referencing our adopted labor expenses to the CPI or automatically passing through any expense the utility negotiated without examining it for reasonableness under the circumstances existing at the time the expense is incurred. To do so, particularly with an expense such as labor, would destroy any incentive the utility has to take a firm position at the bargaining table. Under SDG&E's wage settlement, the amount of the increase is not definitely known at this time and will not be definitely known until almost three months after this decision is issued. Since we must set rates based on reasonable expense levels under those circumstances, we will use 12.5 percent for the 1981 labor portion of expenses.

14. Wage and Price Standards

As required by the Commission's Resolution No. M-4704, the company presented its report on Council on Wage and Price Stability (COWPS) Voluntary Pay and Price Standards, in Exhibit 57, which was sponsored by company witness Higgins. With respect to the Voluntary Pay Standards, it was demonstrated that the company's proposed wage increases of 9.5 percent for 1980, and up to 13.5 percent for 1981, comply with the applicable provisions of the program.

Witness Higgins pointed out that COWPS has adopted interim price standards which basically extend the existing standards through December 1980. It is unknown at this time whether any price standards will be in effect during the test year. If, however, it is assumed that the current standards were continued into 1981, SDG&E's original request would have exceeded the Price Deceleration and Gross Margin Standards.

It must be understood that these standards are voluntary, and that COWPS has encouraged regulatory commissions to determine qualification for exemptions where appropriate. COWPS has stated:

> "The commissions may administer the profit margin limitation exception and exceptions for extreme hardship and gross inequities. Commissions may find it necessary to grant exceptions in order to enable utilities to raise capital in order to finance construction that is needed to serve customers, or to meet federal policies that seek to reduce dependence on oil."

SDG&E agreed, in Exhibit 57, that its rate request does not comply with the "profit margin limitation exception". However, it argues that its financial condition is such that forced compliance with the standards would cause extreme hardship and create gross inequity. Therefore, the company contends that it should be excepted from the standards.

We note that SDG&E's rate request in this proceeding is a bare-bones minimum requirement. During the test year, the company will be faced with substantial nondiscretionary cost increases and ever-rising capital requirements to finance new construction in one of the fastest growing regions of the country. At the same time, the company is attempting to improve its tenuous financial condition and credit rating.

Based on the record in this case, it would be proper for the Commission to conclude that the level of rate relief to be granted in this proceeding is fair and reasonable. Any further reduction in the amounts found reasonable would cause extreme financial hardship and gross inequity. Even staff has agreed that the sought rate of return is fair and reasonable and that its recommended expense levels are appropriate. Accordingly, we find that SDG&E should be excepted from the standards because of substantial 1981 nondiscretionary cost increases and capital requirements. To do otherwise would result in extreme hardship and gross inequities to the company.

D. RATE BASE

1. General

SDG&E and staff estimates, as presented in late-filed Exhibit 70, are as follows (thousands):

	SDG&E	Staff	Difference
Electric	$1,105,504	$1,055,401	$50,103
Gas	159,180	159,611	-431
Total	$1,264,684	$1,215,012	$49,672

The principal areas of disagreement are discussed below.

2. Plant in Service

SDG&E and staff differ as to the correct plant in service balance to be used in the 1981 test year calculation of rate base. The difference for the Electric Department is only $186,000 and for the Gas Department only $73,000; however, the difference was due to an oversight by staff. We will adopt the company's figures.

3. Net Plant Additions

There is a difference of $1,902,000 in the Electric Department and $110,000 in the Gas Department in the estimate of net plant additions in test year 1981. The company performed a study which reviewed the estimated expenditures and scheduled completion dates of some 200 individual projects which were included in the 1980 and 1981 net plant additions on a weighted average basis.

Staff developed a ratio of net plant additions to plant in service beginning balances, for each recorded year, from 1975 to 1979. These five ratios were then averaged. The resulting average ratio was applied to the company's estimated 1981 plant in service beginning balance to develop the staff's 1981 net plant additions.

The staff's method does not allow for any possible growth trend or known net plant additions. We will adopt the company's estimate.

4. Fuel in Storage

There is a difference between SDG&E and staff as to the appropriate amount of fuel in storage which should be included directly in the Electric Department rate base. Staff accepted the company's estimated prices for oil but disagreed with the number of barrels of oil which should be recognized. This amounted to a rate base difference of $33,424,000.

The company developed its fuel in storage estimate through the use of a computerized model which considered the beginning inventory level of 1981, additional purchases, and the monthly fossil fuel burn requirements for that year. This process resulted in quantification of the number of barrels of oil SDG&E would have, on a weighted average basis, in 1981. This equated to an 84-day burn for residual oil, the major component of the account.

Staff witness Van Lier reviewed SDG&E's 1979 recorded monthly day burn average of 65 days' burn for residual oil and adopted that level as reasonable for test year 1981.

SDG&E points out that the Commission has previously stated a policy of allowing the equivalent of 90 days' burn in fuel in storage (D.84577). This policy has been reaffirmed most recently in two cases: for PG&E, based on test year 1980 in D.91107 and for Edison, based on test year 1979 in D.89711. SDG&E submits that if this policy is appropriate for PG&E and Edison, it is even more appropriate for SDG&E due to obvious differences in operation of the systems.

SDG&E states that the Commission has encouraged utilities to enter long-term fuel oil supply contracts to ensure adequate inventory levels (D.81931). The Commission has also found, upon investigation by an outside independent consultant, that SDG&E's fuel oil procurement policies and practices are not imprudent (D.90404, Finding 11).

On the other hand, staff states that the amount of fuel in storage was not an issue in SDG&E's previous 1979 test year case. Additionally, the appropriate amount of fuel in storage was not examined in prior PG&E and Edison cases which authorized a 90 days' burn for those utilities. Thus, the instant recommendation is the first staff effort to determine what a reasonable level of fuel in storage should be.

Staff submits that 65 days' burn will adequately protect the ratepayer in 1981. According to staff, current market conditions indicate that fuel oil supplies will be available to SDG&E throughout 1981. If a change in fuel oil availability should occur in 1981, staff suggests the Commission may allow SDG&E to maintain a higher level of fuel in storage in 1982.

The quantity of oil held in storage has become a significant rate base item because of the high price of oil. Nevertheless, price is not the controlling factor upon which a decision should be made as to what is a reasonable quantity of oil to be held in storage. As we view it, factors that should be considered include: abnormal weather conditions, gas availability, off-system purchases, force majuere contract provisions, etc. We do not believe that a temporary oil oversupply situation is a factor that should be given much weight, since world oil supply is highly dependent on the international political situation and could change overnight.

While we commend staff for its initiative in examining the question, we will not adopt its adjustment. If staff proposes a similar adjustment for test year 1982, we will expect a detailed analysis that considers as-expected conditions for the test year rather than reliance upon a prior recorded year which may or may not be representative of the test year. We will adopt the company's estimate for test year 1981.

5. Working Cash Allowance

The working cash component of rate base is intended to compensate the utility for the carrying cost of money associated with goods and services which have been purchased, and for which revenues have not yet been collected from the ratepayer. At the same time, it is intended to ensure that the ratepayer receives the full benefit in the converse situation. The level of working cash is directly affected by the adopted revenues and expenses.

The only area of contention in working cash allowance involves the appropriate number of lag days to be used for the purchased fuel oil item of the calculation. Staff has used 22 days and the company contends that 15 days is more appropriate. There is no dispute as to the dollar value to be used in the calculation; however, this one item could have a revenue impact of $2.3 million.

In the case of fuel oil, it has been established on the record that the supplier, in effect, finances the oil from the time of shipment until it is paid for, approximately 22 days later. The ratepayer is also paying the carrying cost of the oil, under both the company's and staff's calculations, from the time it enters physical inventory, 15 days before payment. The purpose of the working cash adjustment is to avoid a double counting by returning to the ratepayer the corresponding benefit the company receives of "free" financing for the same 15 days.

SDG&E points out that the only reason a working cash reduction is appropriate at all is that the ratepayer is carrying an associated burden. If he were not, then he would be entitled to no negative adjustment. For this reason, a 15-day lag is more correct than 22 days. The ratepayer is not carrying the oil as a fuel in storage rate base item for the seven-day period from the time it leaves the refinery to when it reaches SDG&E's tanks in San Diego.

SDG&E's witness Malquist testified that the company's rate base treatment commences when the oil is taken into physical inventory. He also confirmed that this was true of the staff's calculations, since staff witness Van Lier used recorded 1979 inventory levels, which do not include oil in transit, as the basis of his recommendations. SDG&E submits that staff witness Han's 22-day lag proposal would be appropriate only if the company had included oil in transit in the fuel in storage rate base item.

While we commend staff and witness Han for raising the issue in the first instance, since SDG&E originally showed zero lag days, we will adopt SDG&E's amended estimate of 15.07 lag days.

6. <u>Plant Held For Future Use</u>

Staff recommended that $9,130,000, relating to two South Bay gas turbines, be excluded from rate base for ratemaking purposes.

These particular turbines have been the subject of controversy for some years. Unfortunately, the company has had various planned uses for them, which for a number of reasons have not materialized. It should be noted, however, that the Commission has confirmed that SDG&E's prior actions with regard to these turbines have been proper and, in fact, rate recovery for the abandoned projects has been allowed (D.87639, D.90405).

The Uniform System of Accounts, Account 105, specifies that for accounting purposes the utility must have a definite plan for use if an item of equipment is to be included therein. Nowhere in the Uniform System of Accounts is the definition further amplified. The Commission in D.87639 affirmed the requirement that there must be a definite plan for all plant held for future use entered in Account 105.

Staff requested the company to furnish its definite plan for future use of the South Bay gas turbines. In response, the company offered 11 possible applications for the gas turbines prefaced by the admission that "a specific plan for utilizing the gas turbines is not available".

SDG&E's rate base witness Williams later testified that although the company has a number of "definite" plans for use of the gas turbines, its two primary options are a cogeneration project with Kelco and an installation at Navy's new hospital site. SDG&E, however, was unable to submit any documentation of its negotiations with Kelco or the Navy.

The South Bay gas turbines have been included in Account 105 since 1974 and were included in rate base in July 1977. Since July 1977, the ratepayer has paid an additional $3,000,000 in rates because the gas turbines were included in rate base although the turbines were never put into operation.

Staff submits that the $9.1 million cost associated with the South Bay gas turbines should be excluded from rate base until SDG&E can furnish a single definite plan for their future use. The ratepayer already has paid a return on the turbines for over three years without receiving any benefit. Inclusion of the gas turbines in rate base for the 1981 test year would compel the ratepayer to continue to pay a return for yet another year without adequate assurance from the utility that the gas turbines will be used.

Since SDG&E is filing a 1982 test year amendment to this application, staff recommends that the South Bay gas turbines be excluded from rate base for the 1981 test year. If SDG&E is able to provide concrete evidence of a definite plan for the use of the gas turbines, then the cost of the turbines may be included in the rate base in 1982. However, at this time, staff submits that the company has failed to demonstrate that there is a definite plan for use of the turbines. Accordingly, we agree that the $9.1 million cost associated with the turbines should be excluded from rate base as recommended by staff.

7. Conservation Voltage Regulation (CVR) Program

As discussed in the conservation section of this opinion, we will add $1,597,000 equipment costs to 1981 plant additions (Exhibit 38), to reflect that amount of capital expended over the course of the test year.

VIII. CONSERVATION

A. SUMMARY

SDG&E proposed an expenditure level of $15.3 million for conservation programs for test year 1981. Staff agreed to the various programs proposed by SDG&E but recommended a total reduction of approximately $2.2 million to the company's proposed expenditure level. The staff's adjustments include: (a) reduction in advertising expenses for various programs amounting to $1 million; (b) reductions in various programs amounting to $126,000; and (c) reduction of the utility-requested supplemental reserve from $1 million to $100,000. SDG&E stipulated to the staff's total level of expenditure of $13.1 million.

In view of the high electric rates now existing in the SDG&E's service area and the significant price-induced conservation, estimated for test year 1981, we have reduced staff-recommended expenditure levels by a further $1.8 million to a total of $11.3 million for test year 1981. This adjustment reflects a reduction of $750,000 for anticipated delay in implementing the Residential Conservation Service (RCS) Program and deletion of all Priority 2 and 3 expenses shown in Exhibit 38 for the various programs.

The following Table IX shows the test year 1981 conservation programs, SDG&E's estimate, staff's estimate, and the adopted expenditure levels for the various programs.

Table IX

San Diego Gas & Electric Company

COMPARISON OF CONSERVATION EXPENSES
Test Year 1981

Program	SDG&E 1/	Staff 2/	Adopted
	(Dollars in Thousands)		
Residential			
Residential Audits (RCS)	$ 2,534	$ 2,551	$ 1,801 3/
Appliances	141	141	91
Community Outreach	145	145	146
Builder Incentives	839	739	459
Insulation Incentives	847	847	326
Products	325	325	225
New Products Testing	100	100	-
Shows and Exhibits	146	101	79
Brochures	145	145	109
Meter Conversion	46	46	47
Customer Service	520	520	405
Pilot Light	219	80	99
Spirit	20	20	-
Residential Direct Mail High Users	142	142	-
Advisory Service	255	256	246
Consumer Affairs	168	168	61
Subtotal	6,592	6,326	4,094
Commercial-Industrial			
P.A.C.E.	1,031	1,031	637
Assigned Accounts	765	765	766
Pump Testing	8	8	8
Street Lights	29	29	29
Energy Saver Lights	493	493	394
Recognition	180	180	-
Cogeneration	140	140	140
Subtotal	2,646	2,646	1,974

1/ Exhibit 7, Table 1, adjusted to reflect final position of SDG&E prior to stipulation.

2/ Exhibit 17, Table 2, adjusted to reflect final position of staff.

3/ Reduction of $750,000 to reflect delay in implementing RCS Program.

Table IX

San Diego Gas & Electric Company

COMPARISON OF CONSERVATION EXPENSES
Test Year 1981

Program	SDG&E[1/]	Staff[2/]	Adopted
	(Dollars in Thousands)		
Others			
Solar	$ 501	$ 301	$ 501
Awareness	309	100	77[4/]
School Education	-	-	169[5/]
CVR	1,643	1,643	46[5/]
Peak	1,001	550	424
Supplemental Reserve	1,000	100	1,100
Load Management	-	-	-
Subtotal	4,454	2,694	2,317
Ancillary	1,444	1,444	1,357
Subtotal - Expensed	15,136	13,110	9,742
CVR Capitalized			1,597
Total Conservation Programs			$11,339

4/ Included in Account 920.

5/ CVR Program; total $1,643,000; capital $1,597,000; and expense $46,000.

Other adopted figures reflect Exhibit 38 - Priority 1 expenses. Priority 2 and 3 expenses were deleted.

B. PROGRAMS

1. General

SDG&E's Exhibit 7 provides a description of each conservation program and lists energy savings. Staff's Exhibit 17 discusses the reductions recommended by staff to expenditure levels proposed by SDG&E for the various programs. We will discuss the areas which go beyond the scope of the company's and staff's reports.

2. Mandated Programs

In addition to programs ordered by this Commission, the company is required to implement programs mandated by other agencies. The mandated programs comprise: (1) the RCS Program, and (2) the Load Management Standards with its four constituent programs.

The RCS Program, discussed subsequently, is estimated to cost approximately $2.5 million per year and is expected to last five years. However, present indications are it is unlikely the program will be implemented on a full year basis in 1981.

Load Management Standards have been established by the California Energy Commission (CEC) pursuant to legislative decree. These standards set basic requirements for: (1) a Residential Peak Load Cycling Program, (2) a Swimming Pool Filter Pump Program, (3) a Large Commercial Customers Program, and (4) a Small Commercial Customers Program. By D.92024 dated July 15, 1980, we allowed SDG&E $3.9 million to implement load management programs in 1980. Expenditures for 1981 are expected to be approximately the same. Load management expenses are not included in this proceeding since SDG&E recovers these expenses, separately, through a Load Management Adjustment Billing Factor and a balancing account.

All the other programs shown in the preceding Table IX are programs authorized by this Commission.

3. RCS Program

SDG&E states that the National Energy Conservation Policy Act (Act) requires it to implement a RCS Program. The program is a five-year project designed to substantially increase the installation of energy conservation measures, including renewable resource measures, in existing residential buildings.

According to SDG&E, the Act requires the company to provide:

(1) A Home Energy Audit upon the residents' request.

(2) Information about estimated savings in energy costs for recommended conservation measures and practices.

(3) Arrangements upon request for the purchase, installation, financing, and billing of energy conservation and renewable resource measures, with appropriate attention given to consumer protection.

(4) Post-installation inspections.

SDG&E's Exhibit 38 shows a cost breakdown for the RCS Program for test year 1981 as follows:

Labor	
Administrative	$ 107,000
Clerical	500
Supervision	7,500
Contract	1,302,000
Total Labor	1,417,000
Nonlabor Expenses	
Employee Expense	5,000
Materials	5,000
Transportation	270,000
Uniforms	17,000
Equipment	30,000
Mailing Costs	71,000
Total Nonlabor	398,000

Communications	
Major Media	$ -
Collateral	12,000
Reproduction	363,000
Total Communications	375,000
Incentives	-
Data Processing	344,000
Total Cost	$2,534,000

The staff Energy Conservation Branch recommends an expenditure of $2,551,000 for this program for test year 1981.

SDG&E's witness Hunter testified that in accordance with the Act, SDG&E would be implementing the procedures as set forth by the CEC. He stated that the original submittal of CEC made in June 1980 had been rejected by the Department of Energy (DOE). He expected approval of a plan sometime in 1981.

Since this time, the CEC plan, subject to certain modifications, has received DOE approval. We expect SDG&E to be able to begin its RCS Program around the second quarter of 1981 and will therefore allow a reduced amount to provide costs to reflect this delay. Accordingly, we will deduct $750,000 from the staff-recommended estimate for this program and allow $1,801,000 to cover test year 1981 costs. Funding for this program on a full scale basis will be addressed in SDG&E's test year 1982 rate case. Hopefully, cost-effectiveness will be optimized subject to the CEC-adopted plan.

4. New Customer Conservation Program

The controversy surrounds an amount of $520,000 which SDG&E included as a conservation expense. In previous rate cases this item was considered as an operating expense; however, in this proceeding SDG&E decided to include it as a conservation expense. Staff witness Barnhardt deleted this item from conservation expense Account 908 because he believed it belonged in operating expense Account 903. Staff witness Chan, responsible for operating expense accounts, did not include the item in his estimate of Account 903 for the test year. Therefore, SDG&E correctly pointed out that staff had denied recovery of this item.

Under this program, when a new customer or a customer changing residence signs for service, SDG&E's customer service clerks will ask if the customer wishes to spend a few moments discussing some of the most effective conservation actions he can take to reduce consumption. The clerk then identifies several conservation actions the customer can use and then offers to send him additional conservation literature which will provide the customer with detailed information on all conservation action which he is interested in. Staff witness Barnhardt thought the time spent by the customer service clerk was minimal; however, SDG&E points out that it is significant in the aggregate. SDG&E estimates the equivalent time of 32 persons out of a total 318 persons is spent on conservation activity when signing up new customers over the course of a year.

The ALJ requested staff to further investigate the matter, to review prior recorded expenses for the two accounts, and to report back. The results of staff's investigation are described in Exhibit 66. Staff witness Barnhardt then agreed that the item should be considered a conservation expense. However, staff accountants disagree with the dollar amount, since they believe there was some double counting of this item in Account 903 and Account 908.

We ask that staff and SDG&E look into this matter further for the 1982 test year phase. For test year 1981 we will adopt the 1979 recorded figure of $326,000 escalated for wage increases to $405,000.

5. Conservation Voltage Regulation (CVR) Expenses

According to SDG&E, the company's CVR Program was pursued in 1980 without any authorized revenues in rates. Expenses for this program of $576,100 for 1980 were capitalized rather than expensed. The remaining estimated labor costs of $48,175 were expensed in 1980. The company is now proposing that authorized costs for the CVR Program be expensed in 1981. For 1981, CVR expenses could be broken down as follows: labor approximately $46,000 and equipment approximately $1,597,000.

The costs for 1981 relate to the purchase and installation of equipment such as distribution transformers, switch capacitors, line conductors, and miscellaneous equipment as indicated in Exhibit 43. The company is requesting that all of these equipment costs of the CVR Program in 1981 be expensed. SDG&E's witness Hunter provided four reasons why the Commission should grant the company this expense treatment. First, expense treatment in the 1981 test year would allow the company to be made whole after capitalizing these costs in 1980. Second, the expected life of some of this equipment is uncertain at this time because it is new, not very reliable, and may be short-lived. He stated that, in fact, some of the equipment installed for this program has already had to be replaced. Third, some of the equipment may not remain on the system into the future. Fourth, the company's present financial condition would justify such treatment. SDG&E submits that for each of the foregoing reasons, this equipment should receive expense treatment for 1981.

We should point out that the Commission has provided SDG&E with special ratemaking treatment in several areas because of its present financial condition. However, we are not convinced this is an area that requires special treatment and for ratemaking we will treat the CVR Program costs in accordance with normal ratemaking procedures. Accordingly, the labor estimate of $46,000 will be treated as an expense item and the equipment cost of $1,597,000 will be treated as a capital expenditure in test year 1981. The total expenditure level for this program will remain unchanged.

6. Supplemental Reserve

SDG&E has requested revenues sufficient to cover unanticipated conservation requirements of regulatory agencies which are to be implemented between test years. This proposal has been labeled the supplemental reserve. It should be noted that the company stipulated to the staff's estimates which recommended disallowance of such a supplemental reserve. However, the staff used a portion of this aspect of the company's request in the amount of $100,000 for funding a conservation potential study. Notwithstanding the stipulation, SDG&E believes such a supplemental reserve would be useful to fund programs or activities not included in the company's proposed expense estimates, and should be considered in the 1982 test year proceeding.

SDG&E states that in the past the company has found itself in the position of being compelled to implement conservation programs without revenues authorized in rates to recover such expenses. SDG&E cites, for example in 1979, the CEC promulgated certain mandatory load management standards which the company sought to implement beginning in January 1980. A.59350 was filed in December 1979, and the company began incurring certain expenses on the programs with the good faith belief that rates would be granted to cover such interim efforts. Finally, in July 1980 D.92024 was promulgated which provided offset rate relief for the anticipated expenses to be incurred in implementing the load management standards. However, due to the question of retroactive ratemaking, an issue not raised in the proceeding, program expenses in the amount of $550,000 incurred before that decision were disallowed. According to SDG&E these expenses which were disallowed will go forever unreimbursed.

SDG&E points out that another example of the necessity for a supplemental reserve can be found in the mandated RCS Program which could become effective in 1981. At the present time, SDG&E has no dollars in rates for the RCS Program; however, the company must move forward with that program to gain experience, to train personnel, and to determine what problems or conditions exist in the market.

SDG&E notes that in making this request, it attached two important conditions to the proposal which will protect the ratepayer. First, these funds would only be used to satisfy state or federal directives for conservation activities not previously funded through a rate case procedure. Second, these funds would be received with the understanding that monies not specifically spent to satisfy such a mandate would be subject to refund or result in reduced rates. In any event, dollars from the supplemental reserve would not be spent for any purpose without Commission authorization. SDG&E submits that this proposal is absolutely necessary to protect not only the company from a reoccurrence of the disallowance in D.92024 but also to protect the ratepayer.

SDG&E states that presently there are other conservation programs pending before this Commission which could necessitate expenditures which are not anticipated in the 1981 test year filing. SDG&E cites for example C.10260, the line extension case which is now pending and could necessitate more expenditures. Also, solar financing A.59724 is now pending which arose out of OII 42. According to SDG&E, that filing may not have been necessary if a supplemental reserve, subject to refund, had been in place. Furthermore, SDG&E suggests there is the possibility that it will be requested to implement a low or zero interest financing program for conservation products in 1981.

We adopt as reasonable for test year 1981 a supplemental reserve of $1,100,000. This amount includes $100,000 for the staff-recommended conservation potential study program. We believe a supplementary reserve of the above amount is reasonable since there is a real possibility SDG&E will be required to implement certain programs not allowed for in 1981 rates. For example: the Summer Peak Contingency plan may have to be implemented at short notice; the RCS plan may need additional funding if there is a higher customer response for energy audits than allowed in the adopted estimate; start-up of zero interest financing for weatherization may have to be implemented; and establishment of a weatherization training center may become necessary. Expenditures authorized under the supplemental reserve will be spent only on the designated program and SDG&E will be required to provide a full accounting of such amounts.

However, we stress that no supplemental reserve funds may be used unless prior approval has been received from staff for amounts up to $300,000. Such approval must be in writing over the signature of the Executive Director. For amounts in excess of $300,000 in a single year, prior Commission approval must be obtained. Unexpended funds will be subject to refund.

C. POSITION OF PARTIES ON CONSERVATION

1. Position of City

City is in favor of cost-effective conservation programs that are not duplicative but emphasizes that there is a limit to the amount of money ratepayers can pay for conservation programs. Therefore, City recommends that only the programs listed as Priority 1 in Exhibit 38 be authorized for test year 1981. (This amounts to an expenditure level of $10.9 million.)

City believes the record in this proceeding shows that the major reduction in the use of gas and electricity is due to increasing price rather than conservation programs. City refers to the testimony of SDG&E's witness Strachan who testified that the estimated reduction in 1981 test year usage of electricity and gas due to price was 708 GkWh and 38,548 Mtherms, respectively, whereas the reduction due to conservation was 354 GkWh and 6,580 Mtherms, respectively, which means that about 85 percent of the reduction in usage is due to price. City questions the need for a myriad of conservation programs when price alone has such a very large effect on reducing usage.

We agree with City regarding the significant price-related conservation expected in test year 1981 but also believe that conservation programs have assisted people in being more responsive to price. We will recognize both of these effects when setting conservation expenditure levels for the test year.

2. Position of CalPIRG

CalPIRG states that it is becoming increasingly apparent that consumers react negatively to many of SDG&E's conservation programs. It notes that during the public witness phase of this proceeding, consumers repeatedly stated that it was price increases rather than company conservation efforts that caused them to conserve more energy. CalPIRG believes that in order to avoid a potential backlash against SDG&E, the Commission must authorize substantially less conservation advertising, brochures, school programs, products testing, and other promotional activities. Accordingly, CalPIRG recommends an expenditure level of $7.5 million for test year 1981 conservation programs.

As previously stated, we will make appropriate allowance for price-related conservation in setting 1981 expenditure levels.

3. Position of Executive Agencies of the United States (Federal Agencies)

The Federal Agencies support conservation activities but believe expenditures in this area should not be rubber-stamped. They point out that conservation expenditures recommended by staff and stipulated to by the company for test year 1981 of $13.1 million, compared to 1980 as-expected expenditures of $6.0 million,[5/] represent a 118 percent increase. They believe an increase of such magnitude deserves careful scrutiny.

5/ RT 1715 - Less load management expenses.

According to Federal Agencies, the magnitude of the proposed expenditures in the area of conservation has resulted in a public outcry on the part of the customers of SDG&E, and this is evidenced by the public witness testimony in this proceeding. Federal Agencies believe that SDG&E has failed to demonstrate that all expense levels are reasonable and therefore request that conservation expenditures be maintained at 1980 levels ($6.0 million) adjusted for inflation.

4. Position of Staff Legal Division

Legal Division states that SDG&E's conservation expenses per customer for test year 1981 are high compared to its fellow California energy utilities and refers to the staff-prepared table in Exhibit 14, page 12-2, which follows:

COMPARISON OF 1981 TEST YEAR CONSERVATION EXPENSES INCLUDING LOAD MANAGEMENT1/

	Gas		
	$/Cust.	¢/Therm	¢/Therm Over Lifeline
SoCal Gas2/	8.55	.36	.45
SDG&E			
Staff	7.26	.47	.72
Utility	8.70	.57	.86
Adopted	5.67	.37	.56
PG&E3/	5.99	.23	.29

	Electric		
	$/Cust.	¢/kWh	¢/kWh Over Lifeline
SoCal Edison			
Staff & Utility	12.12	.60	.71
SDG&E			
Staff4/	16.60	1.21	1.53
Utility	18.66	1.36	1.73
Adopted	13.34	0.97	1.23
PG&E	14.22	.78	.94

1/ All estimates are from the staff results of operation reports. To be on a comparative basis, staff customer and sales estimates were used.

2/ Test year 1981 per D.92497.

3/ Test year 1980 per D.91107.

4/ Includes $3.9 million for load management.

Legal Division reminds the Commission of the increasing customer dissatisfaction with rising energy costs and points to the hundreds of written complaints from customers in Borrego Springs and elsewhere, as well as the several hundred who appeared at the public hearings in Oceanside and San Diego, several of whom specifically objected to conservation advertising at ratepayers' expense.

Legal Division believes that identifying conservation expenditures with energy and capacity savings is elusive. Reference is made to SDG&E's witness Dougherty's testimony that price is the most significant factor in achieving reduced consumption. It is also noted that SDG&E has a number of measurement techniques, all are empirical and it is developing a new econometric model of measurement due to the deficiencies in the present methods.

Legal Division points to the RCS Program estimated at $2.5 million which could be delayed in implementation, thereby effecting a commensurate reduction in 1981 expenses.

Legal Division further believes that there is latitude for the Commission to reduce 1981 conservation expenditures beyond the level recommended by the Energy Conservation Branch since reduced levels would not have a material impact on the utility's conservation goals, given the present indistinct relationship between programs and energy savings.

D. DISCUSSION

1. General

Both SDG&E and staff are in agreement that the programs listed in the preceding Table IX should be implemented in test year 1981. SDG&E's Exhibit 7 provides a description of each program and lists energy savings. Staff Exhibit 17 discusses the reductions recommended by staff to expenditure levels proposed by SDG&E for the various programs. We concur with all the reductions recommended by staff and need not repeat the details since they are set forth in the staff's report. Accordingly, we will limit our discussion to areas which go beyond the staff's report and recommendations.

2. Management Discretion

As stated previously, SDG&E stipulated to the total level of expenditure recommended by staff for test year 1981; however, SDG&E emphasizes that it should have some management discretion and flexibility to change levels of expenditure within programs if it should be determined that the company cannot achieve a conservation goal or if a program becomes inappropriate due to changed circumstances. We agree that since SDG&E is accountable for the results of the programs, it must retain some degree of management discretion which will give it the flexibility to increase efforts in one program or decrease those in others.

On the other hand, we believe it is important that the company keep staff fully informed on changes of funding levels within previously authorized programs. Accordingly, the company should seek approval from staff, in writing over the signature of the Executive Director, before shifting amounts exceeding 10 percent of the authorized level of any affected program up to $300,000 in a single year. For amounts exceeding $300,000 in a single year, prior Commission approval should be sought.

As stated previously, no supplemental reserve funds may be used unless prior approval has been obtained from staff for amounts up to $300,000. Such approval must be in writing over the signature of the Executive Director. For amounts exceeding $300,000 in a single year, prior Commission concurrence should be obtained. Unexpended funds are subject to refund.

3. Price-Related Conservation

The testimony presented by SDG&E shows estimated 1981 price-related conservation levels of 85 percent for gas and 66 percent for electric over 1979. Appliance efficiency and building standards account for an additional 12 percent electric conservation. Therefore, according to the testimony, 15 percent of gas conservation and 22 percent of electric conservation are attributable to 1981 conservation programs.

The customers of SDG&E, during the public witness hearings, repeatedly spoke of SDG&E's rates being the second highest in the nation and asked the Commission to cut back on advertising and conservation programs, since they felt that a myriad of programs was not necessary with such high rates.

We believe that there is evidence that price is significantly affecting sales, especially in the residential class, and we will consider this factor in setting expenditure levels for 1981 conservation programs.

4. Cost-Effectiveness

Cost-effectiveness is a crucial element in any evaluation of a utility's conservation programs. SDG&E's Exhibit 39 shows that with certain exceptions, the majority of SDG&E's programs for test year 1981 are cost-effective.

Cost-effectiveness has been an issue regarding the RCS Program. This is a federally mandated program which is required to be instituted by state or local regulation. This program will be implemented some time in 1981, after SDG&E has received from its rate-approving body rates to offset expenses. We encourage the company and CEC to optimize the cost-effectiveness of this program.

5. Energy Savings

Certain of the programs described in SDG&E's Exhibit 7 do not show kWh or therm savings in their respective program descriptions; they are: the New Conservation Product Development Program; the Shows and Exhibits Program; the New Customer Conservation Program; the Conservation Community Spirit Program; the Consumer Affairs Program; the Energy Efficiency Recognition Program; the Insulation Incentive Program; Cogeneration; the Conservation Awareness Communication Program; and the Supplemental Reserve. The reason why these programs do not show energy savings in Exhibit 7 was explained by SDG&E's witness Hunter. These programs, with the exception of Cogeneration and the Supplemental

Reserve, are described as "support programs". That is, they support the actions taking place in other areas. According to SDG&E, because these programs support other programs, they are no less essential to achieving the company's conservation goals. Consequently, the savings specifically attributable to these programs are included in the savings denotations of the programs they support. For example, the Insulation Incentive Program which contributes to the savings is included in the table supporting the Conservation Products Program, and the New Conservation Product Development Program savings are also included in the Conservation Products Program.

A review of the company's conservation showing in this proceeding confirms that each program has been shown to be appropriate for achieving this Commission's conservation purposes. With this Commission's increasing emphasis on conservation, we believe the adopted programs are reasonable and should be implemented during test year 1981, with some adjustment in expenditure level to reflect increased price-induced conservation resulting from the high electric and gas rates prevailing in SDG&E's territory.

6. <u>Conservation Advertising Expenses</u>

A broad area of discussion in this proceeding has been the level of advertising expenditures requested by the company for 1981. The company's stipulations caused SDG&E's dollar request for advertising efforts to be reduced from $3.5 million to $2.5 million, the level recommended by staff. The amount included in the $2.5 million figure for major media advertising is $1 million. SDG&E believes any further reduction in expenditures in the area of advertising would affect the company's ability to achieve its conservation goals.

IMAGE EVALUATION
TEST TARGET (MT-3)

6″

IMAGE EVALUATION
TEST TARGET (MT-3)

6"

As an example, SDG&E cites the goals of the Solar Energy Program set by the Commission. Since the present incentives under that program have been decreased from the level originally contemplated, SDG&E believes advertising is all the more necessary to make the customer aware of what is offered and its benefits. As the incentives decrease, SDG&E states it must increase the pool from which it can draw interested customers and this is done through advertising. On the other hand, SDG&E agrees that if the goals for the Solar Energy Program were to be decreased, then the advertising dollars could be decreased commensurately.

Although he acknowledged that the effectiveness of advertising is difficult to measure, SDG&E's witness Hunter spoke to the success of SDG&E's conservation advertising programs. Furthermore, witness Hunter pointed out that in some instances research has determined that there is a very high percentage of customers influenced by company communications regarding conservation. He pointed out that there is a very high correlation between SDG&E's conservation advertising efforts connected with the Energy Efficient Appliances Programs and purchases of the recommended appliances.

SDG&E states that the purpose of its conservation advertising dollars requested in this proceeding goes beyond conservation messages per se. For example, the Conservation Awareness Communications Program advertising amount is attributable to safety messages to the customer. This additional purpose for these expenses was noted by the staff report.

SDG&E believes the scrutiny which its advertising expenses have received in this proceeding points up the fact that the company cannot achieve its conservation goals in a vacuum. SDG&E emphasizes it must be adequately funded to get its conservation messages to the public in order for customer reaction to follow.

We note the mounting public criticism against media advertising and expect this criticism to get louder as rates climb still higher. However, we realize that some level of advertising is necessary in order to get the conservation message across. The price of energy, although a significant factor in reducing consumption, will not by itself accomplish all the desired results. Therefore, the Commission must ultimately decide what levels of ratepayer funding are reasonable for advertising expense.

As stated previously, the company requested $3.5 million and staff recommends an advertising expense level of $2.5 million. We believe further reductions are possible by eliminating Priority 2 and 3 advertising shown in Exhibit 38. Accordingly, we will adopt an advertising expenditure level of $2 million as reasonable for test year 1981.

7. Adopted Expenditure Levels

While it is extremely important that SDG&E accelerate its 1981 conservation programs over present levels ($6.0 million), we believe that some reduction in the $13.1 million staff-recommended level of expenditure can be made without significantly reducing program levels.

Accordingly, we will delete $750,000 from the RCS Program since it will not be implemented on a full year basis. We will also delete all Priority 2 and 3 expenditures shown in Exhibit 38 for the various conservation programs. These adjustments provide a 1981 test year expenditure of $11.3 million as shown in the preceding Table IX.

We should point out that a level of $11.3 million for conservation programs represents an 88.3 percent increase (from $6.0 million) over 1980 levels. In addition, SDG&E has $3.9 million in separately funded load management programs for 1981. Accordingly, we adopt as reasonable a level of expenditure for test year 1981 conservation programs of $11.3 million.

IX. RESEARCH AND DEVELOPMENT

With the exception of an amount of $300,000 for an R&D blanket, the company and staff are in agreement regarding programs and levels of expenditure. SDG&E's Exhibit 7 provides a description of the programs and staff Exhibit 13, the General Report, discusses the staff review of the programs.

Expenses for R&D are included in electric production expense, A&G expense, and in rate base. The following tabulation shows the total amounts:

Table X

R&D PROGRAMS
Test Year 1981

Ac. No.	Item	SDG&E	Staff	Adopted
		(Thousands of Dollars)		
	Production Expenses			
506	Particle Fallout Program Amortization	$ 906.00	$ 906.00	$ 906.00
506	Magma Geothermal O&M	260.00	260.00	260.00
506	Niland Geothermal Amort.	600.00	600.00	600.00
506	Heber Geothermal Program*	2,791.3	2,791.3	2,791.3
506	Expanded Geothermal Program Amortization	471.6	471.6	471.6
	A&G Expense			
930	Misc. General Expenses	5,110.00	4,810.0	4,810.0
	Rate Base			
	RD&D Plant Capitalized 2,060 x .1129	232.6	232.6	232.6
	Total	$10,371.5	$10,071.5	$10,071.5

*SDG&E revised its original amount of $6.6 million to reflect delay in receiving Department of Energy approval of its program (RT 691).

SDG&E's request for the $300,000 R&D blanket is discussed under A&G expense - Account 930.

Staff recommends that the Commission order SDG&E not to cancel or defer R&D expenditures to reduce the overall levels authorized for the programs. On the other hand, SDG&E emphasizes that it should have some management discretion and flexibility to change levels of expenditure within programs if it should be determined that the company cannot achieve a R&D goal or if a program becomes inappropriate due to changed circumstances. We agree that since SDG&E is accountable for the results of the programs, it must retain a degree of management discretion which will give it the flexibility to increase efforts in one program or decrease those in others. However, SDG&E will be required to keep staff fully informed of any deviations and be prepared to explain any change from authorized expenditure levels.

We believe that SDG&E's R&D expenditures past, present, and future must be evaluated on a project-by-project basis. Therefore, we expect staff in SDG&E's next general rate proceeding to verify the reasonableness of differences between recorded R&D expenditures and those which we will adopt in this decision. Furthermore, we expect staff to make recommendations on the propriety of SDG&E's total R&D expenditures and those which we will adopt in this decision. Furthermore, we expect staff to make recommendations on the propriety of SDG&E's total R&D effort and to recommend ratemaking adjustments if warranted by the staff's evaluation of R&D expenditures.

X. RATE DESIGN

A. COMPANY'S AND STAFF'S PROPOSALS

SDG&E submits that its rate design proposals, as presented by witness Strachan, are intended to be consistent with the Commission's recent decisions regarding rate design. As presented in its Exhibit 5, the electric rate design reflects a uniform cents per kWh increase to each customer class. SDG&E agrees that within the residential class, the rates should be structured to reflect the appropriate lifeline-nonlifeline differential. SDG&E stipulated to the use of the gas rate design presented by staff in Exhibit 19.

Staff witness Garg recommended a uniform cents per kWh increase to base rates. He stated that his recommendation, Exhibit 18, Option 2, was in accordance with SDG&E's last three rate decisions and will have the least impact on the domestic class. He considered two other alternatives: (1) Option 1 - same percentage increase to each class, and (2) Option 3 - setting the average domestic rate equal to the total system rate. The staff domestic rate structure is based on a 50 percent differential or 1.5 times ratio between lifeline and nonlifeline, as compared with SDG&E's 1.378 factor. The 50 percent is based upon the same differential adopted in SDG&E's A.59643, D.91971 dated July 2, 1980.

B. POSITION OF PARTIES

1. Position of Farm Bureau

Farm Bureau states that the staff-proposed uniform cents per kWh increase for all customer classes would further promote discrimination against certain classes of customers and provide unjustified preferential treatment of the domestic class. The staff's recommendation, according to Farm Bureau, ignores the fact that the growth in the domestic class is the very basis for this rate increase request and yet the class which is primarily responsible for the increase is given preferential treatment. Farm Bureau notes that neither SDG&E nor staff performed any marginal cost allocation studies or cost of service studies in arriving at their proposals. Farm Bureau supports cost of service and recommends adoption of a uniform percentage increase to preserve the differential between customer classes.

Regarding gas rate design, Farm Bureau questions the relationship between the priority of a customer and the price that the customer pays for gas. Farm Bureau cites the example of two agricultural customers conducting the same operation, in the same geographical area and in the same marketplace. Under the current priority system and pricing schedules, where customer A uses 99,900 cubic feet per day and customer B uses 100,500 cubic feet per day, they will be paying different rates because the former customer will be on the GN-1 schedule and the latter on the GN-3 schedule. According to Farm Bureau, this simple example shows the discriminatory pricing policy which presently exists.

Farm Bureau points out that the priority system was created to provide for the interruption of natural gas service in time of a shortage. However, with the forecast for a plentiful supply into the future, Farm Bureau believes the only effect of the priority system is to create economic discrimination in pricing.

Farm Bureau opposes adoption of SDG&E's sales estimate subject to the refund provision discussed previously. Farm Bureau believes the proposal lacks specifics concerning the refund provision since it is not clear whether the refunds would be made to the class which contributed any overcollection or whether there would be a refund "across the board".

We note Farm Bureau's concern regarding possible refunds. We will consider this matter in a subsequent proceeding, if there are refunds payable.

Regarding agricultural time-of-use (TOU) rates, SDG&E stated that it will work with staff and Farm Bureau regarding development of an optional agricultural TOU program. Farm Bureau believes that such a TOU rate will benefit agricultural customers, as well as the utility, and will strive toward the development and implementation of such a rate.

Farm Bureau fully supports staff and SDG&E in their recommendation that the Agricultural Pump Test Program is a very effective conservation program.

2. Position of Executive Agencies of the United States (Federal Agencies)

Federal Agencies support a uniform percentage increase since this will more closely reflect cost of service. According to Federal Agencies, a uniform percentage increase to base rates will still heavily subsidize the residential class but would freeze these subsidies at the present level. On the other hand, a uniform cents per kWh increase, as recommended by staff, would result in further deterioration in the relationship between the cost of supplying utility service to a customer class and the rates charged that class.

Federal Agencies point out that the staff proposal has the least impact on the largest class and must correspondingly give a much larger increase to the remaining smaller number of customers. Federal Agencies agree that the application of a methodology which has the least impact on the largest class of customers is a laudable goal; however, it strikes them as totally inappropriate to put on blinders as to the related effects of applying this methodology. Federal Agencies urge the Commission to order rates which are nondiscriminatory, just, and reasonable and to consider the impact on various classes of customers, whether large or small, in determining these rates.

3. Position of City of San Diego

City requested SDG&E to commence preparation of energy-only rates for customer-owned low-pressure sodium vapor lamps for street lighting. SDG&E agreed to commence preparation of a study and make advice letter filings for such rates. A significant amount of hearing time was devoted to this subject and the testimony indicates there are several factors that have to be carefully evaluated in developing the schedules. We will consider this matter further in test year 1982.

4. Position of CalPIRG

CalPIRG states that it represents the interests of low and moderate income residential utility customers. CalPIRG recommends adoption of staff's proposal of a uniform cents per kWh increase to base rates since this option minimizes the impact of the proposed increase on the residential customer. CalPIRG believes that this is appropriate in that residential customers, unlike many of their commercial and industrial counterparts, do not have the opportunity to pass through their increased utility costs to others.

In regard to the lifeline-nonlifeline differential for domestic electric rates, CalPIRG recommends that this Commission adopt a 60 percent figure, rather than the 50 percent differential chosen by staff witness Garg. According to CalPIRG, such a differential will probably increase conservation and will help ease the burden of this increase on the low-income lifeline consumer.

CalPIRG concurs with staff witness Garg's recommendation against increasing the per customer service charge, but urges the Commission to move towards the eventual elimination of the charge. CalPIRG also urges looking toward a multi-tiered inversion approach in setting future domestic electric rates.

On the gas side, CalPIRG recommends adoption of staff witness Barrett's multi-tiered residential rate design as presented in Exhibit 19. However, CalPIRG also recommends reduction of the lifeline rate (Tier 1) to a level equal to 70 percent (as opposed to Barrett's 80 percent) of the total system average. CalPIRG submits this modification will help ease the impact of this increase on the low-income lifeline customers.

C. DISCUSSION

We note the positions of the various parties in this proceeding. The question of rate design, marginal costs, cost of service, and customer service charges will be thoroughly reviewed in the next phase of this proceeding. For test year 1981 we will adopt, as reasonable, a uniform cents per kWh increase for base rates. The lifeline differential within the residential class will be 50 percent. For gas rate design, we will adopt the staff's proposal for test year 1981.

Pending consideration of SDG&E's 1982 test year, we are concerned that measures be taken to address the difficult situation of residents of the low desert area, as represented by residents of Borrego Springs at our hearings. We intend to address these problems in the case of SDG&E by the same means we are employing in the case of Southern California Edison Company pursuant to Decision No. 92549 issued today. We direct SDG&E to cooperate with our staff and affected customer groups in developing optional general service time-of-use rates to alleviate the effect of rigid demand charges in the desert area. We also request SDG&E, in formulating its pending application for an expanded residential weatherization incentives program, to place special emphasis and priority upon reaching residents of the low desert area.

D. TIME-OF-USE RATES

1. General

By A.59785, SDG&E seeks authority to implement Schedule A-4 TOU, General Service-Time Metered Rates.

SDG&E, in compliance with the Commission's order in C.9804, has proposed to implement new TOU rates for its electric customers with demands in the 500 to 1,000 kilowatt (kW) range. Proposed Schedule A-4 TOU was initially filed by Advice Letter No. 490-E on September 21, 1979. After a protest by the California Hotel and Motel Association, staff requested that the advice letter be withdrawn and submitted as an application. SDG&E, therefore, withdrew Advice Letter No. 490-E on January 3, 1980 and filed A.59785 on July 1, 1980, setting forth its TOU rate proposal. A.59785 was consolidated with the instant general rate A.59788, and hearings were held on proposed Schedule A-4 TOU on October 16, 1980.

SDG&E's Electric Department tariffs currently include Schedule A-5 TOU, which applies to customers with demands in the 1,000 to 4,500 kW range. Proposed Schedule A-4 TOU is similar in design to the existing A-5 TOU schedule, and extends the TOU rate coverage to customers with demands in the 500 to 1,000 kW range. SDG&E estimates that 187 electric customers who are currently served on Schedules A, P, PA, and A-5 would be transferred to Schedule A-4 TOU. The proposed A-4 TOU rates have been designed to produce the same revenue from these customers as would be produced if they remained on their current schedules so there is no revenue impact on A.59788.

Schedule A-4 TOU is intended to encourage affected customers to shift their usage off SDG&E's peak load periods. In order to promote customer understanding of this rate proposal, SDG&E originally served those effected with copies of Advice Letter No. 490-E and comparisons showing estimated bills for 12 months at existing rates and 12 months on Schedule A-4 TOU. After filing A.59785, SDG&E notified all affected customers of a workshop which was held on October 3, 1980. Customers who attended the workshop had questions answered by SDG&E and staff personnel, and were provided with updated billing comparisons.

2. Impact of A-4 TOU Rates

Regarding the impact of the proposed A-4 TOU rates on customers, SDG&E's witness Asmus testified that based on 12 months' recorded data through August 1980, he estimates that under the proposed A-4 TOU rates, based on 187 customer accounts: 11 customers would have billing decreases of 5 to 10 percent; 46 customers decreases of 0 to 5 percent; 81 customers increases of 0 to 5 percent; 42 customers increases between 5 to 10 percent; 5 customers increases between 10 and 15 percent; and 2 customers with increases in excess of 15 percent. These figures assume no change in the customers' usage pattern.

Witness Asmus further testified that if customers shifted load as estimated in the rate design - 5 percent decrease in billing demand due to TOU rates and 3 percent shift each from consumption from on-peak to semi-peak and semi-peak to off-peak - the impact on customer bills would be: 19 customers with a decrease of 5 to 10 percent; 52 customers decreases of 0 to 5 percent; 84

customers increases of 0 to 5 percent; 28 customers increases of 5 to 10 percent; 2 customers increases of 10 to 15 percent; and 2 customers increases in excess of 15 percent. Regarding the two customers receiving increases in excess of 15 percent, he stated that these customers were large water pumping customers and he believed it was possible for them to shift usage out of the peak period.

Staff witness Robert L. Mahin supported the rate design proposed by SDG&E. He testified that the revenue requirement for the proposed Schedule A-4 TOU is based upon the historical usage and TOU patterns of the customers whose demands would qualify them for the schedule. He agreed with SDG&E's assumption that the effect of the proposed schedule would be a 5 percent decrease in customer maximum demand (kW) during the on-peak period and a shift of 3 percent of the on-peak consumption (kWh) to semi-peak and 3 percent of the semi-peak consumption (kWh) to off-peak.

Witness Mahin further testified that the proposed rate design conforms to the following criteria: (1) recover approximately the same revenue that would be produced by the same customers on their present rate schedules; (2) be compatible with alternate rate schedules (particularly A-5 TOU) for which the A-4 TOU customers may also be eligible; (3) encourage load management in the sense of controlling on-peak demand; and (4) must not create billing hardships for customers with normal load profiles.

3. Public Witness Testimony

Two customer representatives attended the October 16, 1980 hearing and commented on proposed Schedule A-4 TOU. Mr. Dewey Baggett, executive director of the Hospital Council for San Diego and Imperial Counties, stated that hospitals in general cannot shift their usage patterns and will, therefore, probably experience increased costs which will have to be passed on to the consumer. Mr. Baggett would like to see the Commission give special recognition to hospitals in its adopted rate design as, he believes, other jurisdictions apparently do.

John Lovett, representing Industrial Castings, Inc., was primarily concerned with the fact that in SDG&E's proposed tariff, the on-peak hours begin earlier than those in Southern California Edison Company's tariffs. Lovett believes that this puts his company in a competitive disadvantage with Los Angeles area firms. The solution he proposes is a statewide consistency in the TOU periods. However, in view of Lovett's comments about the effects of different peak hours on competition between similar businesses in different service areas, SDG&E's witness Asmus agreed that the company should review its peak hours to determine if any change is warranted. We expect a report at the 1982 test year hearing.

4. Position of California Community Colleges (Community Colleges)

Community Colleges are a statewide system of 106 community colleges, five of which are affected by SDG&E's TOU-4 rate application.

Community Colleges state that the community college system operates from September to June, being open between the hours of 7:00 a.m. and 11:00 p.m. There are approximately 1.2 million students enrolled in the 106 community and junior colleges in California. A profile of the average enrollee reveals a part-time student who is 27 years old, who works during the day and attends classes afterwards. The majority of the enrolled are part-time students who normally attend late afternoon and/or evening classes which are necessarily scheduled during the on-peak hours. Because they serve the community, Community Colleges must schedule classes at a time when their students are able to attend. Thus, in Community Colleges' case, the facilities reach maximum use during the on-peak period.

Community Colleges point out that they cannot continue to serve the community and its students and avoid the peak-hour rate. They have no flexibility to shift their electricity demands to off-peak hours. The very nature of the community services and the programs provided forbid any shifting of schedules. In the community college situation, it is the clientele (i.e., the students) and the activity (an evening education), not the rate design, which are instrumental in determining how much energy is used and when.

Community Colleges state that the new A-4 TOU rate is unfair - requiring an unwarranted expenditure of public funds. Community Colleges agree that while the implementation of TOU schedules to curb peak load, promote efficient use of existing power plants, and diminish the need for new plants are admirable goals, they should be accomplished by a method that takes into account the customer's capability to respond to that method and the realization of the goals. Community Colleges disagree with staff's assertion that customers exempt from TOU would feel free to indiscriminately load the system during on-peak periods. Community Colleges believe the TOU rate concept and its purposes should be implemented and pursued only after careful consideration of the socioeconomic consequences of its application on customers such as the public-funded community colleges. Community Colleges submit that such an action should not have been undertaken at the expense of the public interest and the well-being of the residents of this State.

5. Discussion

We recognize that certain customers may have less flexibility in their usage patterns than others, but special exemptions are inappropriate at this time. The TOU periods proposed for Schedule A-4 TOU are essentially the same as those applicable to SDG&E's other TOU customers and are based on the average load shape for the Electric Department. While it is true that other factors can be used to determine the appropriate on-peak, off-peak, and semi-peak hours, deviations from the proposed schedule should be ordered only after a full review of all TOU tariffs. We plan such a review in SDG&E's test year 1982 general rate case.

We adopt, as reasonable, for test year 1981 the proposed Schedule A-4 TOU rates shown in Exhibit 5, Table A, Page 2 of 10, adjusted to reflect the revenues adopted in this opinion.

XI. TEST YEAR 1982

We note staff used six months of 1980 recorded data in preparing its estimates for test year 1981. We believe for test year 1982 it will be more meaningful if staff's estimates include a full year of 1980 recorded data. Accordingly, the hearing schedule for test year 1982 will be adjusted to allow for this. Evidentiary hearings will not commence until all parties have had ample time to review staff's report. However, the matter will be submitted in accordance with the Regulatory Lag Plan so that new rates may be placed in effect at the commencement of test year 1982.

XII. FINDINGS AND CONCLUSIONS

A. FINDINGS OF FACT

1. SDG&E is in need of additional revenues, but its revised request of $107.7 million for test year 1981 is excessive.

2. A rate of return of 14.50 percent on common equity, previously found reasonable for test year 1979 in D.90405, is reasonable for test year 1981.

3. A 14.50 percent rate of return on common equity, when applied to the adopted capital structure for test year 1981, will yield an 11.36 percent average rate of return on rate base for SDG&E's gas and jurisdictional electric operations. This level of return will provide an after-tax interest coverage of 2.3 times, a reduction from the previously authorized level of 2.7 times in D.90405 for test year 1979.

4. To earn an average rate of return on rate base of 11.36 percent in test year 1981, the additional annual gross revenue requirement is $80,943,500 for electric service and $14,957,900 for gas service. The total increase in gross annual requirement is $95,901,400.

5. The rate of return on common equity and rate base, together with the increased revenue requirement herein found to be justified for test year 1981, is authorized with the understanding that further hearing will be continued on this matter in establishing SDG&E's revenue requirement for 1982.

6. CalPIRG's motion to dismiss is denied since no party was unduly hampered in participating in this proceeding.

7. A 12.5 percent interest cost for bankers' acceptances is reasonable and is adopted for test year 1981.

8. It is reasonable to adopt SDG&E's electric sales estimate for test year 1981 on condition that revenues generated from sales in excess of the adopted sales estimate will be refunded and SDG&E would not seek to recover undercollections, if any, from the ratepayer.

9. It is proper to allow recovery of the base rate portion of lifeline refunds made by SDG&E to its customers in the amount of $596,755. This will not increase SDG&E's rate of return previously authorized.

10. SDG&E may seek recovery in test year 1982 of the $4.9 million electric production expenses for San Onofre Unit No. 1, excluded from test year 1981 for nonconformance with the Regulatory Lag Plan.

11. SDG&E's request for an R&D blanket of $300,000 is not adopted since SDG&E has an expenditure level of $10.1 million for R&D in 1981 and may rearrange its priorities to accommodate any change in R&D goals or programs.

12. SDG&E will not be paying income tax during 1981 on revenues received for the Heber Binary Project and since recovery of project costs is on a dollar-for-dollar basis, no Schedule M adjustment for income taxes need be allowed in test year 1981. This matter will be considered in subsequent proceedings.

13. The staff's position on ITC carry-overs reflects traditional ratemaking policy and is adopted.

14. A wage increase allowance of 12.5 percent is reasonable for test year 1981.

15. SDG&E's proposed wage increase complies with the Voluntary Pay Standards.

16. The adopted test year estimated increase in revenues herein found reasonable are not in compliance with the Federal Wage and Price Guidelines issued by the Council on Wage and Price Stability. However, adequate justification exists for granting SDG&E exemption on grounds of hardship and financial necessity.

17. The $9,130,000 related to two South Bay gas turbines is excluded from rate base because the company does not have a definite plan for their use. The items may be reconsidered in test year 1982 if SDG&E has a definite plan for their use by then.

18. There is no need for special ratemaking treatment for CVR costs. These costs will receive standard ratemaking treatment.

19. There is evidence that price is causing significant conservation and will be recognized in setting expenditure levels for SDG&E's 1981 and future conservation programs.

20. An appropriate level of conservation expenditure for test year 1981, excluding load management, is $11.3 million. This represents an 88.3 percent increase over 1980 levels.

21. Cost-effectiveness is a concern in the proposed RCS Program. SDG&E needs to take steps to maximize cost-effectiveness of this program.

22. A supplemental reserve of $1,100,000 is reasonable for test year 1981 conservation programs. These funds must not be used without prior authorization and unused funds will be subject to refund.

23. Accurate measurement of the specific savings of individual conservation programs and general savings of overall conservation efforts are crucial to the determination of cost-effectiveness. SDG&E's present measurement techniques need improvement.

24. A conservation advertising level of $2 million for test year 1981 is reasonable.

25. An R&D expenditure level of $10.1 million for test year 1981 is reasonable.

26. An increase in electric rates on a uniform cents per kWh basis is reasonable for test year 1981.

27. The staff-recommended gas rate design is reasonable for test year 1981.

28. Making Schedule A-4 TOU mandatory for all general service customers with demands above 500 kW will promote energy conservation and load management.

29. The record in this proceeding does not provide an adequate basis for determining the relative merits of low-pressure and high-pressure sodium vapor lamps. SDG&E has agreed to study the matter further and prepare appropriate advice letter filings.

30. In order to better evaluate SDG&E's 1982 test year showing it is necessary that 1980 recorded data, on a full year basis, be included in the staff's results of operation. Therefore, the hearing schedule should be adjusted to allow staff sufficient time to include this data in its showing.

31. The increase in rates and charges authorized by this decision is justified and is reasonable; the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable.

32. Estimated electric sales and revenues for test year 1981 are subject to significant fluctuations.

33. A reasonable method for treating such electric revenue fluctuations is to refund any base rate revenues for 1981 exceeding our adopted base rate revenues of $363,023,500 for the six major customer groups: Domestic, Lighting and Small Power, Large Power, Time-Of-Use, Agricultural Power and Street Lighting.

B. CONCLUSIONS OF LAW

1. SDG&E should be authorized to file the revised electric rates which are set forth in Appendix B and the revised gas rates set forth in Appendix C of this decision.

2. The revised rates based on test year 1981 results of operation should produce additional gross revenues of $80,943,500 for the Electric Department and $14,957,900 for the Gas Department. The total additional gross revenue increase should be $95,901,400.

3. The effective date of the ensuing order should be the date hereof because there is immediate need for rate relief concurrently with the commencement of the 1981 test year pursuant to the Commission's Regulatory Lag Plan.

INTERIM ORDER

IT IS ORDERED that:

1. San Diego Gas & Electric Company is authorized to file with this Commission revised tariff schedules for electric rates as set forth in Appendix B and gas rates as set forth in Appendix C attached hereto. By this reference, these tariff schedules are made a part hereof on or after the effective date of this order. The revised tariff schedules shall become effective four days after the date of filing and shall comply with General Order No. 96-A. The revised rate schedules shall apply only to service rendered on or after the effective date hereof.

2. The staff's results of operation for test year 1982 shall include 1980 recorded data on a full year basis, and the hearing schedule shall be adjusted accordingly.

3. Cal PIRG's motion to dismiss the application is denied.

4. Any portion of the $1.1 million supplemental reserve for conservation left unexpended at the end of test year 1981 will be subject to refund.

5. SDG&E shall maintain a record of all base rate revenues for the six major customer groups.

6. Any base rate revenues for 1981 exceeding adopted revenues for the six major customer groups shall be refunded or credited to ratepayers as directed by the Commission.

The effective date of this order is the date hereof.

Dated December 30, 1980, San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
CLAIRE T. DEDRICK
LEONARD M. GRIMES, JR.
Commissioners

Commissioner Vernon L. Sturgeon, being necessarily absent, did not participate in the disposition of this proceeding.

APPENDIX A

LIST OF APPEARANCES

Applicant: Stephen A. Edwards, Jeffrey Lee Guttero, and William L. Reed, Attorneys at Law.

Intervenor: David X. Durkin, Attorney at Law, for the San Diego Energy Coalition.

Interested Parties: Etta G. Herbach, Attorney at Law, for the Department of the Navy and all Executive Agencies of the Federal Government; John W. Witt, City Attorney, by William S. Shaffran, Deputy City Attorney, for City of San Diego; Antone S. Bulich, Jr., Attorney at Law, for California Farm Bureau Federation; Philip R. Mann, Attorney at Law, for Cogeneration Group; James Tanner and Kenneth Strassner, for Kimbe y-Clark Corporation; Burt Pines, City Attorney, by Ed Perez, Deputy City Attorney, for the City of Los Angeles; Harry K. Winters, for the University of California; William L. Knecht, Attorney at Law, for California Association of Utility Shareholders; Riddle, Walters & Bukey, by Halina F. Osinski, Attorney at Law, for California Community Colleges; William D. Smith, Attorney at Law, for the County of San Diego; and Richard L. Hamilton, Attorney at Law, for Western Mobile Home Association.

Commission Staff: Randolph L. Wu and Timothy E. Treacy, Attorneys at Law.

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

Applicant's electric rates, charges, and conditions are changed to the level or extent set forth in this appendix.

SUMMARY OF BASE RATES

GENERAL SERVICE (SCHEDULE A)

	Per Meter Per Month
Non-Demand Metered Customers	
Customer Charge	$ 2.20
Energy Charge: All kwhr, per kwhr	$ 0.04272
Demand Metered Customers	
Customer Charge	$10.00
Demand Charge, per kw of billing demand	$ 1.00
Energy Charge: All kwhr, per kwhr	$ 0.03323

GENERAL SERVICE (SCHEDULE A-5)

	Per Meter Per Month
Customer Charge	$10.00
Demand Charge, per kw of billing demand	$ 3.96
Energy Charge:	
First 200 kwhr per kw of billing demand, per kwhr	$ 0.02072
All excess kwhr, per kwhr	$ 0.01772

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

GENERAL SERVICE - TIME METERED (SCHEDULE A-4 TOU)

	Per Meter Per Month
Customer Charge	$10.00
Demand Charge:	
Customer's Maximum Demand During the On-Peak Period	$ 6.05/kwhr
Energy Charge:	
On-Peak	$ 0.03122
Semi-Peak	$ 0.02322
Off-Peak	$ 0.01522

GENERAL SERVICE - TIME METERED (SCHEDULE A-5 TOU)

	Per Meter Per Month
Customer Charge	$20.00
Demand Charge	
Customer's Maximum Demand During the On-Peak Period	$ 5.84/kwhr
Energy Charge:	
On-Peak	$ 0.02252
Semi-Peak	$ 0.01752
Off-Peak	$ 0.01502

GENERAL SERVICE -INCLUDING CUSTOMER GENERATION (SCHEDULE A-5 CG)

	Per Meter Per Month
Customer Charge	$20.00/mo.
Demand Charge:	
Billing Demand	$ 5.84/Kw
Net Energy Charge:	
On-Peak	$ 0.02252
Semi-Peak	$ 0.01752
Off-Peak	$ 0.01502

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

GENERAL SERVICE - LARGE - (SCHEDULE A-6)

	Per Meter Per Month
Customer Charge..	$600.00
Peak Demand Charge for Customer Contribution to Monthly System Peak	$ 7.67/kw
Energy Charge:	
On-Peak..	$ 0.01872
Semi-Peak..	$ 0.01372
Off-Peak...	$ 0.01122

GENERAL SERVICE - LARGE - INCLUDING CUSTOMER GENERATION (SCHEDULE A-6 CG)

	Per Month
Customer Charge..	$600.00
Demand Charge:	
Billing Demand.......................................	$ 6.40/kw
Net Energy Charge:	
On-Peak..	$ 0.01872
Semi-Peak..	$ 0.01372
Off-Peak...	$ 0.01122

DOMESTIC SERVICE (SCHEDULE DR)

	Per Meter Per Month
Customer Charge..	$ 2.20
Energy Charge (to be added to Customer Charge):	
Lifeline, per kwhr..................................	$ 0.02617
Non-Lifeline, per kwhr..............................	$ 0.04205

MULTI-FAMILY SERVICE (SCHEDULE DM)

	Per Meter Per Month
Customer Charge..	$ 2.20
Energy Charge (to be added to Customer Charge):	
Lifeline, per kwhr..................................	$ 0.02617
Non-Lifeline, per kwhr..............................	$ 0.04205

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

SUBMETERED MULTI-FAMILY SERVICE (SCHEDULE DS)

	Per Meter Per Month
Customer Charge....................................	$ 2.20
Energy Charge (to be added to Customer Charge):	
Lifeline, per kwhr.................................	$ 0.02617
Non-Lifeline, per kwhr.............................	0.04205

SUBMETERED MULTI-FAMILY SERVICE - MOBILEHOME PARK
(SCHEDULE DT)

	Per Meter Per Month
Customer Charge....................................	$ 2.20
Energy Charge (to be added to Customer Charge):	
Lifeline, per kwhr.................................	$ 0.02617
Non-Lifeline, per kwhr.............................	0.04205

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

LIGHTING - STREET AND HIGHWAY - UTILITY-OWNED INSTALLATIONS
(SCHEDULE LS-1)

Lamp Watts	Approximate Lumens	Class	Dollars Per Electrolier Per Month [1] A	B 1-lamp	B 2-lamp	C 1-lamp	C 2-lamp
Mercury Vapor Lamps							
175	7,000		$12.28	$ -	$ -	$20.90	$32.13
250	10,000		15.56	-	-	24.69	39.09
400	20,000		21.58	-	-	30.92	51.57
700	35,000		35.53	-	-	-	-
1,000	55,000		46.92	-	-	63.53	-
High Pressure Sodium Vapor Lamps							
100	9,500		$ 9.32	$10.52	$18.63	$18.09	$ 26.51
150	16,000		11.60	12.77	23.10	20.92	31.55
250	30,000		18.00	18.95	35.30	27.22	44.01
400	50,000		24.09	25.08	47.64	34.11	57.26
1,000	140,000		48.34	49.40	95.87	64.84	111.95

SPECIAL CONDITIONS

1. Facilities and Rates.

a.(1)(b) Reactor Ballast. Increase the reduction for reactor ballasts to 46¢ for 175 watt lamps and 71¢ for 250 watt lamps.

[1] For comparative purposes, the rates shown include the effect of the ECAC factor currently in effect ($0.07143/kwhr).

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

LIGHTING - STREET AND HIGHWAY - CUSTOMER-OWNED INSTALLATIONS
(SCHEDULE LS-2)

Lamp Watts	Approximate Lumens	Dollars Per Lamp Per Month (1): RATE A Energy Only	RATE B Energy and Limited Maintenance	Surcharge for Series Service
Incandescent Lamps				
	1,000	$ 3.11	$ -	
	2,500	6.44	7.52	
	4,000	9.51	10.59	
	6,000	13.78	14.86	
	10,000	23.04	-	
Mercury Vapor Lamps				
175	7,000	$ 7.91	$ 8.55	$0.49
250	10,000	10.84	11.62	0.63
400	20,000	16.85	17.55	0.92
700	35,000	28.28	29.45	1.66
1,000	55,000	39.79	-	-
High Pressure Sodium Vapor Lamps				
70	5,800	$ 3.33	$ 4.24	
100	9,500	5.55	6.45	
150	16,000	7.70	8.61	
250	30,000	11.58	12.48	
400	50,000	17.63	18.54	
1,000	140,000	39.92	40.82	

LIGHTING - STREET AND HIGHWAY - CUSTOMER-OWNED INSTALLATIONS
(SCHEDULE LS-3)

	Per Meter Per Month
First 150 kwhr per kw of billing demand, per kwhr	$0.05345
All excess kwhr, per kwhr	$ .02248

(1) For comparative purposes, the rates shown include the effect of the ECAC factor currently in effect ($0.07143/kwhr).

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

OUTDOOR AREA LIGHTING SERIVCE
(SCHEDULE OL-1)

Lamp Watts	Approximate Lumens	Dollars Per Lamp Per Month (1) RATE A Streetlight Luminaire	RATE B Directional Luminaire
Mercury Vapor Lamps			
175	7,000	$12.28	-
400	20,000	22.28	-
High Pressure Sodium Vapor Lamps			
100	9,500	$10.05	-
150	16,000	12.33	-
250	30,000	18.88	$19.96
400	50,000	24.83	26.04
1,000	140,000	48.92	50.50

RESIDENTIAL WALKWAY LIGHTING (SCHEDULE DWL)

	Per Month (2)
Facilities Charge:	
Per dollar of utility investment in walkway lighting facilities..........................	$0.021
Energy and Lamp Maintenance Charge (to be added to the facilities charge):	
50-watt high pressure sodium vapor lamp, per lamp..	$3.25
100-watt mercury vapor lamp, per lamp..............	$5.07

(1) For comparative purposes, the rates shown include the effect of the ECAC factor currently in effect ($0.07143/kwhr).

(2) For comparative purposes, the energy and lamp maintenance charge shown below includes the effect of the ECAC factor currently in effect ($0.07522/kwhr).

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

POWER - GENERAL (SCHEDULE P)

	Per Meter Per Month
Customer Charge:	
0 - 500 kwhr	$ 5.00
501 - 2,500 kwhr	10.00
2,501 -10,000 kwhr	15.00
Over 10,000 kwhr	30.00
Energy Charge (to be added to Customer Charge):	
0 - 10,000 kwhr, per kwhr	$ 0.03812
All excess, kwhr, per kwhr	$ .03622

POWER - AGRICULTURAL (SCHEDULE PA)

	Per Meter Per Month
Customer Charge:	
0 - 500 kwhr	$ 4.00
501 - 2,500 kwhr	7.00
2,501 -10,000 kwhr	11.00
Over 10,000 kwhr	20.00
Energy Charge (to be added to Customer Charge):	
All kwhr, per kwhr	$ 0.03372

POWER - DIRECT CURRENT (SCHEDULE PDC)
(CLOSED SCHEDULE)

	Per Meter Per Month
Energy Charge:	
First 500 kwhr, per kwhr	$0.12772
All excess kwhr, per kwhr	.07472

GENERAL SERVICE - PARALLEL GENERATION
(EXPERIMENTAL SCHEDULE A-PG)

	Per Meter Per Month
Customer Charge	$6.47
Net Energy Charge (to be added to Customer Charge):	
First 100 kwhr, per kwhr	No Additional Base Charge
All excess kwhr, per kwhr	$0.04272

RATES - SAN DIEGO GAS & ELECTRIC COMPANY, ELECTRIC DEPARTMENT

DOMESTIC - PARALLEL GENERATION
(EXPERIMENTAL SCHEDULE D-PG)

	Per Meter Per Month
Customer Charge	$6.41
Net Energy Charge (to be added to Customer Charge):	
First 100 kwhr, per kwhr	No Additional Base Charge
Excess kwhr, per kwhr	$0.04205

EXPERIMENTAL DOMESTIC UNCONTROLLED TIME-OF-USE SERVICE
(SCHEDULE D-UTOU)

	Per Meter Per Month
Energy Charge (to be added to Customer Charge):	
On-Peak, per kwhr	$0.04861
Off-Peak, per kwhr	.00000
Lifeline Discount:	
All kwhr, per kwhr	$0.01588

POWER - AGRICULTURAL - PARALLEL GENERATION
(EXPERIMENTAL SCHEDULE PA-PG)

	Per Meter Per Month
Customer Charge:	
0 - 500 kwhr	$ 7.37
501 - 2,500 kwhr	10.37
2,501 -10,000 kwhr	14.37
Over 10,000 kwhr	23.37
Energy Charge (to be added to Customer Charge):	
First 100 kwhr, per kwhr	No Additional Charge
All excess kwhr, per kwhr	$0.03372

SPECIAL CONTRACT 216 (1)

San Diego Gas & Electric Company proposes to increase the monthly charge for each illuminated street name sign from $3.42 to $3.66.

(1) For comparative purposes, the monthly charges shown below include the effect of the ECAC factor currently in effect ($0.07143/kwhr).

A.59788, 59785

Appendix C

San Diego Gas & Electric Company
Gas Department

ADOPTED RATE DESIGN FOR TEST YEAR 1981
BASED UPON RATES EFFECTIVE JULY 7, 1980

(Excluding San Diego Surcharge)

Item	Sales	Present		Adopted		Increase	
	(Mth)	Rate ($/th)	Rev. (M$)	Rate ($/th)	Rev. (M$)	¢/therm	Percent
Residential[1/]							
GL-1, -2	-	-	65	-	65	-	-
CM (1,000's)	5,789[2/]	-	9,841	-	9,841	-	-
Tier I	264,816	0.280	74,148	0.297	78,650	1.7	6.1
Tier II	76,318	.360	27,474	.400	30,527	4.0	11.1
Tier III	12,150	.550	6,683	.600	7,290	5.0	9.1
Total Residential	353,284	.335	118,211	.358	126,373	2.3	6.9
Non-Residential							
CM (1,000's)	348[2/]	-	592	-	592	-	-
GN-1, -2	136,540	0.360	49,154	0.400	54,616	4.0	11.1
GN-3, -4	65,689	.420	27,589	.420	27,589	-	-
GN-36, -46[3/]	-	-	-	-	-	-	-
GL-1, -2	-	-	11	-	11	-	-
GN-5	223,749	.350	78,312	.356	79,655	.6	1.7
Total Non-Residential	425,978	-	155,658	-	162,463	-	-
Total Sales	779,262	-	273,869	-	288,836	-	5.5
Other (Special Contract No. 176)	-	-	18	-	19	-	5.6
Total Revenue	779,262	.351	273,887	.371	288,855	2.0	5.5
W/O LL	514,446	.388	199,739	.409	210,205	2.1	5.5

1/ Residential sales reflect reductions of 2,391 M therms for employee and GT discounts.

2/ Not included in total.

3/ No sales are forecast under these schedules, however, the recommended rate would be three cents less than the corresponding GN-3 or -4 rate, or $0.39.

ATTACHMENT FOR ITEM NO. 5.d
FINANCIAL STATISTICS

		1. months' ended 1980	1979	1978
		(dollars in millions)		
Earnings available to common equity		$257	$292	$202
Average common equity		$2,385	$2,145	$1,918
Rate of return on average common equity		10.76%	13.64%	10.54%
Times total interest earned before FIT: Gross income (both including and excluding AFDC) + current and deferred FIT + total interest charges + amortization of debt discount and expense	W/AFDC	2.02	3.04	2.57
	W/O AFDC	1.45	2.47	2.14
Times long-term interest earned before FIT: Gross income (both including and excluding AFDC) + current and deferred FIT + long-term interest charges + amortization of debt discount and expense	W/AFDC	2.50	3.45	3.01
	W/O AFDC	1.79	2.80	2.61
Bond ratings (end of period)				
Standard and Poor's		AA	AA	AA
Moody's		Aa	Aa	Aa
Times interest and preferred dividends earned after FIT: Gross income (both including and excluding AFDC) + total interest charges + amortization of debt discount and expense + preferred dividends.	W/AFDC	1.78	2.18	1.93
	W/O AFDC	1.30	1.71	1.58
AFUDC		$162	$119	$78
Net income after preferred dividends		$262	$299	$209
%		62%	40%	37%
Market price of common		$25-5/8	$24-1/2	$25-3/4
Book value of common		$33.19	$34.22	$32.57
Market-book ratio (end of period)*		77.2%	71.6%	79.1%
Earnings avail. for common less AFDC + depreciation and amortization, deferred taxes, and invest. tax credit adjust.-deferred.		$215	$419	$379
Common dividends		212	168	133
Ratio		99%	40%	35%
Short-term debt				
Bank loans		$20	$20	$20
Commercial paper		$165	$134	-

Capitalization (Amount & Percent)	1980		1979		1978	
Long-term debt	3089	47.5%	2831	48.2%	2511	47.8%
Preferred stock	882	13.6	814	13.8	701	13.3
Common equity	2530	38.9	2233	38.0	2048	38.9
	6501	100.0%	5878	100.0%	5260	100.0%

* If subsidiary company, use parent's data.

ATTACHMENT FOR ITEM NO. 5d
FINANCIAL STATISTICS

	12 months ended December 31,		
	1980	1979	1978
	(dollars in millions)		
Earnings available to common equity	$34.4	$52.5	$49.6
Average common equity	$570.7	$507.1	$434.1
Rate of return on average common equity	6.03%	10.35%	11.43%
Times total interest earned before FIT: Gross income (both including and excluding AFDC) + current and deferred FIT + total interest charges + amortization of debt discount and expense (less premium) (including AFDC)	1.49	2.16	2.22
(excluding AFDC)	1.07	1.76	1.84
Times long-term interest earned before FIT: Gross income (both including and excluding AFDC) + current and deferred FIT + long-term interest charges + amortization of debt discount and expense (less premium) (incl. AFDC)	2.18	2.49	2.65
(excl. AFDC)	1.56	2.03	2.20
Bond ratings (end of period)			
Standard and Poor's	BBB	BBB	BBB
Moody's	Baa	Baa	Baa
Times interest and preferred dividends earned after FIT: Gross income (both including and excluding AFDC) + total interest charges + amortization of debt discount and expense (less premium) + preferred dividends. (incl. AFDC)	1.31	1.65	1.67
(excl. AFDC)	0.96	1.34	1.37
AFUDC	$39.3	$25.3	$21.8
Net income after preferred dividends	$34.4	$52.5	$49.6
%	114.2%	48.2%	44.0%
Market price of common (per share)	$11.75	$13.125	$14.75
Book value of common (per share)	$16.06	$17.35	$17.41
Market-book ratio (end of period)*	73.2%	75.6%	84.7%
Earnings avail. for common less AFDC + depreciation and amortization, defferred taxes, invest. tax credit adjust. - deferred.	$38.3	$77.9	$71.1
Common dividends	$53.9	$43.6	$35.5
Ratio	71.1%	178.7%	200.3%
Short-term debt			
Bank loans	$50.0	-	-
Commercial paper	$18.0	$93.4	$21.3
Other	$131.0	$60.0	$23.6

Capitalization (Amount & Percent)	Amount 1980	Amount 1979	Amount 1978	Percent 1980	Percent 1979	Percent 1978
Long-term debt	$732.3	$640.1	$573.1	47.8%	45.9%	45.2%
Preferred stock	$213.5	$213.5	$213.5	14.0%	15.3%	16.9%
Common equity	$585.8	$541.2	$480.4	38.2%	38.8%	37.9%

*If subsidiary company, use parent's data.

6-12

City of Anaheim's Answers to

San Onofre Nuclear Generating Station,

Unit Nos. 2 and 3

Docket Nos. STN 50-361 and STN 50-362

Request for Additional Financial Information

Question No. 6: Describe the nature, amount, rations and success of each municipal applicant's most recent revenue and general obligation bond sales. Indicate the current total outstanding indebtedness in each category for each entity.

Answer No. 6: Anaheim sold $84,000,000 in principal amount of Electric Revenue Bonds dated October 1, 1980. The purpose of this Electric Revenue Bond issue was to finance Anaheim's cost of acquisition of its share of the San Onofre Nuclear Generating Station, Units 2 and 3 from Southern California Edison Company. This issue also contained funds to be utilized for the payment of construction costs incurred after the City acquired the ownership interest from Southern California Edison Company. The bonds were rated by Moody's Investor Service as Aa and by Standard & Poor's as A+. The bonds were sold at a 10% discount because the City was limited to paying no more than an 8% interest on the bonds. The net interest cost on the bonds was 9.17%. As of June 30, 1980 the principal amount of outstanding Electric Revenue Bonds was $11,450,000. The Electric Revenue Bonds, Issue of 1980 added to the total amount of outstanding Electric Revenue Bonds of Anaheim results in a total electric revenue bond indebtedness of $95,450,000. The City has not issued General Obligation Bonds since 1963. The principal amount outstanding on General Obligation Bonds of the City as of June 30, 1980 was $2,845,000.

Question No. 7: Provide copies of the official statement for the most recent bond issue. Provide copies of the preliminary statement for any pending security issue.

Answer No. 7: Attached hereto is a copy of the Official Statement pertaining to the Electric Revenue Bonds, Issue of 1980, of $84 mill'on which is the most recent issue of Electric Revenue Bonds sold by the City of Anaheim. There are no pending security issues.

Question No. 8: Provide copies of the most recent annual financial report and the most recent interim financial statements for each municipal applicant. Continue to submit copies of the annual financial reports for each year thereafter as required by 10 CFR Part 50.71(b).

Answer No. 8: Attached hereto are copies of the Annual Report for the period ending June 30, 1980 for the Public Utilities Department of the City and a separate Annual Report for all of the departments of the City, including the Public Utilities Department.

Question No. 9: Is each participant's percentage ownership share in the facility equal to its percentage output of the plant? If not, explain the difference(s) and any resultant effect on any participant's obligation to provide its share of operating cost.

Answer No. 9: Anaheim's percentage ownership share in San Onofre Nuclear Generating Station Units 2 and 3 is 1.66%. Its entitlement to electrical capacity and output of those two units is equal to its percentage ownership share. Units 2 and 3 will, however, share certain facilities (common facilities) with Unit 1 at San Onofre Nuclear Generating Station, in which Anaheim will have no ownership interest. The parties have dealt with this problem by reducing Anaheim's ownership interest in common facilities. The fact that Anaheim owns different percentages of the common facilities than it owns of Units 2 and 3 of San Onofre Nuclear Generating Station should have no effect upon Anaheim's obligation to provide its share of operating cost.

Question No. 10: Describe the rate-setting authority of each municipal applicant and how that authority may be used to insure the satisfaction of financial obligations related to both capital and operating costs of the facility. Describe any restrictions on such rate-setting authority and how this may affect the applicant's ability to satisfy its obligations to the project. Describe the nature and amount of each municipal applicant's most recent rate relief action and the anticipated effects on revenues. Indicate the nature and amount of any pending rate relief action(s).

Answer No. 10: Section 1221 of the Charter of the City of Anaheim provides that the City Council shall establish rates, rules and regulations for the water and electric utilities. This Section further provides that the rates shall be based upon cost of service and shall be sufficient to pay: (a) for operations and maintenance of the system; (b) for payment of principal and interest on debt; (c) for creation and maintenance of financial reserves adequate to assure debt service on bonds outstanding; (d) for capital construction for new facilities and improvement of existing facilities, or maintenance of a reserve fund for that purpose. The provisions of the Anaheim Charter require rates to be established in amounts adequate to pay for both capital and operating costs of any facilities which are part of Anaheim's electric utility. The City's ownership interest in San Onofre Nuclear Generating Station Units 2 and 3 would be a part of the Anaheim electrical utility. Thus, Anaheim believes that its financial position with respect to payment for the capital and operating costs of San Onofre Nuclear Generating Station Units 2 and 3 is sound and that the financial obligations of the City with respect to those matters may be met. Anaheim is not aware of any restrictions on its rate-setting authority which might interfere with its ability to satisfy its obligations to pay its costs associated with San Onofre Nuclear Generating Station Units 2 and 3.

Answer No. 10:
(Continued)

The City's most recent rate action, effective January 1, 1981 was to increase the Energy Cost Adjustment Billing Factor (ECABF) for non-lifeline residential use and other than residential use in order to provide sufficient revenues to recover changes in the wholesale cost of energy. In general, residential rates were increased 0 to 9 percent, commercial rates 7 to 12 percent, and industrial rates about 12 percent. For the system as a whole the increase was about 9.5 percent.

There are no rate relief actions pending and firm decisions on the amount of rate relief required, in the ensuing months have not been made at this time. However, Southern California Edison has filed with the Federal Energy Regulatory Commission (FERC) for an increase in wholesale rates to the City. FERC has accepted the filing and suspended its effective date to July 16, 1981. It is expected that the City will increase its retail rates by July, 1981. These increases may include both fuel cost adjustments and a general rate increase.

Question No. 11: If a membership organization is participating in the joint ownership, explain the contractual arrangement among the members that assures that funds will be available to meet the entities' obligations to the project. Provide copies of the power sales contract.

Answer No. 11: This question is not applicable because Anaheim is financing its own share of the cost of ownership in San Onofre Nuclear Generating Station Units 2 and 3.

Question No. 12: Describe the applicant's plan for financing its share of the cost of eventual shutdown of the facility and maintenance in a safe shutdown condition.

Answer No. 12: The City is currently attempting to determine which of several methods it should adopt to finance its share of the cost of eventual shutdown of San Onofre Nuclear Generating Station, Units 2 and 3. A principal factor in this determination will be that those electric customers who benefit from use of the Generating Station facilities should also pay the cost of shutdown of the Generating Station. It is also the intention of the City to comply with the regulatory requirements of all governmental authorities having jurisdiction to regulate decommissioning cost recovery.

NEW ISSUE

Interest on the 1980 Bonds is exempt, in the opinion of Bond Counsel, from income taxes of the United States of America under present federal income tax laws, and is also exempt from personal income taxes of the State of California under present state income tax laws.

$84,000,000
CITY OF ANAHEIM, CALIFORNIA
ELECTRIC REVENUE BONDS, ISSUE OF 1980

Dated: October 1, 1980 — Due: October 1, as shown below

Interest is payable semi-annually on April 1 and October 1 in each year, commencing April 1, 1981. The 1980 Bonds are issuable as coupon bonds in the denomination of $5,000 registrable as to principal only or as to both principal and interest. Principal of, premium, if any, and interest on the 1980 Bonds are payable at the Corporate Agency Division of Bank of America NT&SA in Los Angeles or San Francisco, California, or at the option of the holders at any other paying agent of the City in Chicago, Illinois and New York, New York.

The 1980 Bonds maturing after October 1, 1990 are subject to redemption on or after October 1, 1990 at 100% of the principal amount thereof. In certain circumstances the 1980 Bonds maturing on or after October 1, 1996 are also subject to redemption on October 1, 1990 at less than 100%, but not less than 95%, of the principal amount thereof. See "Description of the 1980 Bonds" herein.

The 1980 Bonds are being issued for the primary purpose of acquiring a 1.66% ownership interest in the San Onofre Nuclear Generating Station, Units 2 and 3, from the Southern California Edison Company, to pay 100% of the interest on the 1980 Bonds until October 1, 1982 and 50% of the interest on the 1980 Bonds thereafter until December 1, 1983, and to fund the Reserve Fund.

The 1980 Bonds are payable solely from the Gross Revenues of the Electric System of the City and do not constitute a general obligation or indebtedness of the City. The 1980 Bonds rank on a parity with $11,875,000 outstanding electric revenue bonds, and any additional parity bonds which may be issued in the future.

MATURITIES, AMOUNTS, RATES AND YIELDS OR PRICES
(Accrued interest to be added)

$30,475,000 Serial Bonds

Due October 1	Amount	Rate	Yield or Price	Due October 1	Amount	Rate	Price
1984	$1,250,000	8%	6.75%	1991	$2,150,000	8%	100 %
1985	1,375,000	8	7	1992	2,325,000	8	98 1/8
1986	1,450,000	8	7.20	1993	2,525,000	8	96 1/8
1987	1,600,000	8	7.40	1994	2,725,000	8	94 3/4
1988	1,700,000	8	7.60	1995	2,925,000	8	93 3/8
1989	1,850,000	8	7.80	1996	3,175,000	8	92 3/8
1990	2,000,000	8	100	1997	3,425,000	8	91 3/8

$16,650,000 8% Term Bonds Due October 1, 2001 Price 89 3/16%

$36,875,000 8% Term Bonds Due October 1, 2007 Price 87 3/4%

The 1980 Bonds are offered when, as, and if issued subject to approval of legality by O'Melveny & Myers, Bond Counsel, Los Angeles, California. Certain legal matters will be passed upon for the City by its Special Counsel, Alan R. Watts, Esq. Certain legal matters will be passed upon for the Underwriters by their counsel, Mudge Rose Guthrie & Alexander. It is expected that the 1980 Bonds in definitive form will be available in New York, New York, on or about October 30, 1980.

Salomon Brothers

Goldman, Sachs & Co.

Merrill Lynch White Weld Capital Markets Group
Merrill Lynch, Pierce, Fenner & Smith Incorporated

Donaldson, Lufkin & Jenrette
Securities Corporation

October 10, 1980

OFFICIALS OF THE CITY OF ANAHEIM

CITY COUNCIL

John F. Seymour, Jr., Mayor

E. Llewellyn Overholt, Jr., Mayor Pro tem

Ben W. Bay, Councilman

Miriam Kaywood, Councilwoman

Don R. Roth, Councilman

PUBLIC UTILITIES BOARD

Kenneth M. Keesee, Chairman

James H. Townsend, Vice Chairman

Wynn W. Anderson, Member

Richard L. Haynie, Member

Carl J. Kiefer, Member

S. Dale Stanton, Member

Joseph R. White, Member

CITY OFFICIALS

William O. Talley, City Manager

William T. Hopkins, Assistant City Manager

James D. Ruth, Deputy City Manager

George P. Ferrone, Finance Director

William P. Hopkins, City Attorney

Linda D. Roberts, City Clerk

Glenn E. Stewart, City Treasurer

PUBLIC UTILITIES DEPARTMENT

200 South Anaheim Blvd.
Anaheim, California, 92805

Gordon W. Hoyt, General Manager

Edward G. Alario, Assistant General Manager

Darrell L. Ament, Management Services Manager

Ray A. Auerbach, Water Engineering Manager

Edward E. Dumon, Operations Manager

George H. Edwards, Electrical Engineering Manager

Beatrice A. Staley, Conservation Services Manager

James E. Willis, Customer Service Manager

OTHER CITY DEPARTMENT HEADS

Philip M. Grammatica, Data Processing Director

William J. Griffith, City Librarian

Thomas F. Liegler, General Manager, Stadium, Convention Center and Golf Courses

Garry O. McRae, Human Resources Director

Thornton E. Piersall, Public Works Executive Director

Norman J. Priest, Executive Director, Redevelopment Agency/Housing Authority

Bob D. Simpson, Fire Chief

Ronald L. Thompson, Planning Director

George P. Tielsch, Police Chief

BOND COUNSEL

O'Melveny & Myers

FINANCIAL ADVISOR

James J. Lowrey & Co. Incorporated

SPECIAL COUNSEL

Alan R. Watts

CONSULTING ENGINEER

R. W. Beck and Associates

No dealer, broker, salesman or other person has been authorized by the City of Anaheim or the Public Utilities Department or by the Underwriters to give any information or to make any representations, other than as contained in this Official Statement, and if given or made such other information or representations must not be relied upon as having been authorized by the City of Anaheim or the Public Utilities Department or the Underwriters. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the 1980 Bonds by any person in any jurisdiction in which it is unlawful for such persons to make such offer, solicitation or sale.

The information set forth herein has been furnished by the City of Anaheim and the Public Utilities Department and includes information obtained from sources which are believed to be reliable, but is not guaranteed as to accuracy or completeness by, and is not to be construed as a representation by, the Financial Advisor or the Underwriters. The information and expressions of opinion contained herein are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the City of Anaheim or the Public Utilities Department since the date hereof.

In connection with the offering of the 1980 Bonds, the Underwriters may overallot or effect transactions which stabilize or maintain the market price of the 1980 Bonds at levels above those which might otherwise prevail in the open market. Such stabilization, if commenced, may be discontinued at any time.

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OFFICIAL STATEMENT
OF THE
CITY OF ANAHEIM, CALIFORNIA
Relating to its
$84,000,000
Electric Revenue Bonds, Issue of 1980
INTRODUCTION

This Official Statement, including the Cover Page and Appendices hereto, is provided to furnish certain information in connection with the sale by the City of Anaheim, California (the "City") of $84,000,000 Electric Revenue Bonds, Issue of 1980 (the "1980 Bonds"). The 1980 Bonds are issued pursuant to City Charter Section 1210; procedural Ordinance No. 2980, as amended (the "Ordinance"), which incorporates certain provisions of the Revenue Bond Law of 1941 (Chapter 6, Part 1, Division 2, Title 5 of the California Government Code) (the "Bond Law"); and Resolution No. 80 R- 457 of the City Council adopted October 10, 1980 (the "Resolution"). The 1980 Bonds represent a portion of $150,000,000 principal amount of electric revenue bonds authorized by the voters of the City on March 4, 1975. The resolution calling the election established a maximum coupon rate of 8%. The Ordinance established the maximum discount rate at 10% of the principal amount of such electric revenue bonds.

The City previously has issued for the financing of its Electric System: (i) $8,000,000 Electric Revenue Bonds, Issue of 1972 (the "1972 Bonds") authorized by the voters at an election on January 18, 1972; (ii) $6,000,000 Electric Revenue Bonds, Issue of 1976 (the "1976 Bonds") representing a portion of $150,000,000 of electric revenue bonds authorized by voters at the election on March 4, 1975; and (iii) $12,500,000 Electric Revenue Bonds, Second Issue (Subordinated) of 1976 (the "1976 Subordinated Bonds") representing a portion of the same $150,000,000 authorized by voters in 1975. The 1980 Bonds together with the $11,875,000 outstanding balances of the 1972 Bonds and the 1976 Bonds and any future bonds issued on a parity with the outstanding Bonds (herein collectively referred to as the "Bonds") are equally and ratably secured by the security, interest, pledge and assignment created by and the covenants contained in the Resolution.

Purpose of the 1980 Bonds

The 1980 Bonds are being issued to acquire an ownership interest of 1.66 percent (36.5 megawatts) in the San Onofre Nuclear Generating Station, Units 2 and 3, and certain common facilities (collectively referred to herein as the "Project"). The Project is currently owned by the Southern California Edison Company ("Edison") and San Diego Gas and Electric Company ("San Diego"). Edison had been designated as project manager and operator. The City proposes to purchase its share of the Project from Edison. Edison has signed and the City, upon delivery of the Bonds, will sign the Participation Agreement which provides, among other things, for the City to own its share of the Project, for the City to pay Edison for the ownership share and for Edison to construct, operate and maintain the Project on its behalf and on behalf of the other owners of the Project. The City has also signed an Integrated Operations Agreement and upon delivery of the 1980 Bonds will sign a Supplemental Integration Agreement with Edison which agreements provide, among other things, integration of Project power and future City generating resources with those of Edison for operation, including the scheduling and dispatching of power from the City's ownership share of the Project with the scheduling and dispatching of output from Edison's other generating resources. Under the agreements, Edison will continue to supply the City's power and energy requirements over and above the capability of the City's own resources and will credit the City on its monthly billing statements for the power and energy generated by the City's own resources that are integrated with Edison resources.

Use of Proceeds

It is estimated that proceeds of the 1980 Bonds (excluding accrued interest) will be allocated as follows: (i) $50,250,000 to the Construction Account which, together with investment income thereon (estimated to be $4,172,000), will be used to pay the City's proportionate share of the cost of the Project ($54,422,000), (ii) $16,800,000 to the Interest During Construction Account (the "IDC Account") to pay 100% of the interest on the 1980 Bonds until October 1, 1982 and 50% of the interest on the 1980 Bonds thereafter until December 1, 1983, (iii) $8,000,000 to the Reserve Fund so that such Fund shall equal the Maximum Annual Debt Service on the Bonds to be outstanding and (iv) $8,950,000 to allow for certain costs of issuance including a maximum underwriting discount of $8,400,000.

Security and Rate Covenant

The 1980 Bonds will be special obligations of the City and will be secured by a pledge of and lien upon and shall be a charge upon, and shall be payable as to principal thereof and interest thereon and any premiums upon the redemption of any thereof solely from, the Gross Revenues of the Electric System of the City, such Gross Revenues being pledged, charged and assigned for the security of the Bonds. The Electric System of the City (sometimes herein referred to as the "Electric System") consists of the entire electric system of the City including all improvements and extensions later constructed or acquired. Gross Revenues of the Electric System are defined as all rates, fees and charges for providing electric service to persons and real property and all other fees, rents and charges and other income derived by the City from ownership, operation, use or services of the Electric System. (See "Security for and Sources of Payment for the Bonds").

The City is obligated by its Charter and by the Resolution to establish rates and collect charges in an amount sufficient to service the Electric System's indebtedness and to meet its expenses of operation and maintenance, with specified requirements as to priority and coverage. (See "Rate Covenant" under the section "Security for and Sources of Payment for the Bonds".) Electric rates are fixed by the City Council and are not subject to regulation by the California Public Utilities Commission or by any other state agency.

The Bonds do not constitute a general obligation of the City and neither the full faith and credit nor the taxing power of the City is pledged to the payment of principal of or interest on the Bonds.

The Electric System

The Electric System serves the entire area within the City limits of Anaheim. The City purchases at wholesale rates its firm power from Edison and economy energy from Nevada Power Company.

As of the end of fiscal year June 30, 1980, the average number of customers of the Electric System was 82,571 and the total kilowatt hours sold was 1,734,000,000.

Resource Planning

In 1969 R. W. Beck & Associates (the "Consulting Engineer"), as part of a power supply study conducted for the City, recommended the City immediately investigate and negotiate participation in large generating plants. It was concluded by the Consulting Engineer that such participation would result in the lowest cost of power supply for the City. The City has participated in feasibility studies of several large generating stations and the Project will be the first such station to be completed.

As discussed under the subcaption "Other Projects of the Electric System", in addition to the Project, the City has an ongoing program to investigate other potential power supply resources which could be used to serve a portion of its requirements which are currently being purchased from Edison. Of these potential resources, the most definitive is the coal-fired Intermountain Power Project to be located in Southwest Utah. Other possible projects include participation in the coal-fired White Pine Project, the California Coal Project, the North Brawley Geothermal Project and certain hydroelectric projects. Participation in such projects may be on a purchase or ownership basis, with the City's obligation for costs being payable, in certain instances, whether or not energy is received.

The Project

The Project will be owned as tenants-in-common by Edison (76.55%), San Diego (20.00%), City of Riverside (1.79%) and the City (1.66%).

Unit 2 is scheduled for commercial operation in December 1981 and Unit 3 is scheduled for commercial operation in February 1983. As of June 27, 1980, Edison has stated that the construction of Unit 2 was approximately 93% complete and Unit 3 was approximately 63% complete.

Edison has informed the City that all major required permits, except an operating license, have been granted. Edison's current schedule anticipates that the operating license will be received from the Nuclear Regulatory Commission (the "NRC") in sufficient time to meet the projected fuel loading and start up schedules. However, petitions have been granted to certain adverse parties to intervene in the operating license proceedings. The City cannot predict what impact, if any, such intervention will have upon the timing of issuance of, or the conditions included in, the operating license (See "Regulatory Matters").

Construction work on the Project is currently halted due to a strike as part of a western regional work stoppage by the International Brotherhood of Boilermakers. The City is unable to predict the duration of the stoppage, or its impact on the construction schedule or cost of the Project. See "The Project — Status and Schedule of Construction."

The City's share of the construction costs of the Project is currently estimated at $45,475,000, plus a payment to Edison for Edison's carrying costs equal to approximately $8,947,000 (total cost $54,422,000).

The City's ownership share of the Project is expected to provide approximately 8% of the Electric System's energy needs during its first full year of operation.

In the opinion of the Consulting Engineer, the forecasted overall revenue requirements from the sale of electricity by the City are reduced by the City acquiring an ownership share in the Project rather than continuing to purchase all of its power requirements from Edison. The estimated savings to the City resulting from Project ownership increase from $794,000 in the fiscal year ending June 30, 1982 to $9,510,000 in the fiscal year ending June 30, 1990. These projected savings will differ from actual savings to the extent that actual conditions differ from those assumed (See "Appendix A — Consulting Engineer's Report").

Brief descriptions of the 1980 Bonds, the security therefor and the Electric System, and summaries of the Resolution and other documents are included elsewhere in this Official Statement. Such descriptions and summaries do not purport to be comprehensive or definitive. All references herein to the 1980 Bonds, the Resolution and any other documents are qualified in their entirety by reference to each such document. Terms not defined herein shall have the meanings as set forth in the respective documents.

THE CITY'S PUBLIC UTILITIES DEPARTMENT

General Description

Under the provisions of the California Constitution, the Charter of the City and Title 10 of the Municipal Code of the City, the City owns and operates both electrical and water public utilities for the citizens of Anaheim. The Public Utilities Department (the "Department") exercises jurisdiction over both the electric and water systems of the City and is under the supervision of the Public Utilities General Manager (the "General Manager"). The General Manager is responsible for the supervision of the design, construction, maintenance, operation, and upkeep of both the electric and water utilities. The Director of Finance of the City is charged with the accounting and collection of all revenues as well as the administration of the financial affairs of the City. The General Manager and Finance Director are under the direction of the City Manager and the City Manager is appointed by the City Council.

The Department serves water as well as electricity to virtually all the residential, commercial and industrial customers within the City limits. The City has sold $9,350,000 of water revenue bonds, of which $8,505,000 are outstanding, for the purposes of expanding the water system. The City is obligated by its Charter and by the relevant bond resolutions to establish water rates and collect charges in an amount sufficient to service the water system indebtedness and to meet its expenses of operation and maintenance, with specific requirements as to priority and coverage. During fiscal year 1980 the water system sold over 17 billion gallons of water to over 49,000 customers. The funds and accounts of the Electric System and the water system are held separately and the funds and accounts of one system are not pledged to the other system's bonds.

Management of the Public Utilities Department

GORDON W. HOYT, General Manager, is in charge of the City's electric and water distribution systems and has been General Manager since 1964. He is an electrical engineering graduate of the University of Texas and a registered professional engineer. He has served as superintendent of the City of Santa Clara's Electrical Department, and as an Electrical Engineer for Pacific Gas & Electric Company. He is a Senior Member of the Institute of Electrical and Electronic Engineers. He is a member of the Executive Committee and Board of Directors of the Intermountain Power Project. He is a member of the Board of Directors of the American Public Power Association and of the Western Energy Supply and Transmission Associates (WEST). He is a past president of the California Municipal Utilities Association and served on its Board of Governors for six years. Mr. Hoyt's professional experience includes design, construction, and operation of electric generating, transmission, and distribution facilities, as well as management of municipal electric and water utilities.

EDWARD G. ALARIO, Assistant General Manager, is a Business Administration graduate of San Jose State University. In the 15 years prior to his employment with Anaheim, he served as the City Administrator of the City of Bellflower, City Manager and Finance Director of the City of South San Francisco, and Revenue Officer of the City of Sunnyvale.

DARRELL L. AMENT, Management Services Manager, has been with the Department since 1967, and is responsible for formation of overall financial policies and long-range financial plans for the Department, electric and water cost-of-service studies and rate design, utilities accounting and management information, public information, and systems analysis and design. He has a B.A. (1961) and M.A. (1963) in government from Kent State University and has completed additional graduate work in government and public administration at UCLA.

GEORGE H. EDWARDS, Electrical Engineering Manager, has had responsibility for Electric System engineering and planning since 1966. He earned a B.S. in electrical engineering from Texas Technological College in 1950. He is a Senior Member of the Institute of Electrical and Electronic Engineers and has been chairman of the American Public Power Association's Transmission and Distribution Committee. He is a registered professional engineer.

Public Utilities Board

The City Council, by Ordinance No. 3557 approved July 6, 1976, established a Public Utilities Board (the "Board") with the power and duty to make recommendations to the City Council; (i) for the operation and conduct of the electric and water systems, (ii) concerning the establishment of rules and regulations and rates for the operation of the electric and water systems, (iii) concerning the duties and qualifications of the General Manager and other employees of the Department, (iv) concerning the acquisition, construction, improvement, extension, enlargement, diminution, or curtailment of all or any part of the electric and water systems, (v) concerning the annual budget of the Department and (vi) concerning financing, including the issuance of bonds for the Electric System and the water system; and to exercise such other powers and duties as may be prescribed by ordinance not inconsistent with the City Charter.

The Board consists of seven members, none of whom may hold any paid office or employment in the City Government. The members of the Board are appointed by the City Council and may be removed by a majority vote of the City Council. Board members serve four-year terms except that for the initial appointment, three members were appointed for one year, t... members were appointed for two years and two members were appointed for three years.

The present members of the Board and their terms of appointment are:

KENNETH M. KEESEE, Chairman, term expires June 30, 1981. Mr. Keesee is an industrialist and operates a steel tank manufacturing company and an industrial park.

JAMES H. TOWNSEND, Vice Chairman, term expires June 30, 1982. Mr. Townsend is the editor and publisher of "The National Educator," a monthly tabloid newspaper with worldwide distribution.

WYNN W. ANDERSON, term expires June 30, 1982. Mr. Anderson is a teacher in the Anaheim Elementary School District.

RICHARD L. HAYNIE, term expires June 30, 1981. Mr. Haynie is the Plant Superintendent for the Delco-Remy Division General Motors Corporation operations in Anaheim.

CARL J. KIEFER, term expires June 30, 1983. Mr. Kiefer is employed by Rockwell International Corporation. He is in charge of industrial engineering and facilities for the Anaheim operations of Rockwell.

S. DALE STANTON, term expires June 30, 1981. Mr Stanton is a consulting engineer.

JOSEPH R. WHITE, term expires June 30, 1983. Mr. White is a realtor and active in Chamber of Commerce activities and community activities.

DESCRIPTION OF THE 1980 BONDS

General

The 1980 Bonds are being issued in the aggregate principal amount of $84,000,000, are dated October 1, 1980, bear interest at the rates per annum set forth on the cover page of this Official Statement, payable semi-annually on April 1 and October 1 of each year, commencing April 1, 1981, and mature on October 1 in the years and principal amounts set forth on the cover page of this Official Statement.

The 1980 Bonds are issuable in coupon form in the denomination of $5,000 each, registrable as to principal only or as to principal and interest, with the privilege of discharge from registration.

The principal of and premium, if any, and interest on the 1980 Bonds are payable at the Corporate Agency Division of Bank of America NT&SA in Los Angeles or San Francisco, California, or at the option of the holders at any other paying agent of the City in Chicago, Illinois or New York, New York.

Mandatory Redemption

The 1980 Bonds due October 1, 2001 and October 1, 2007 will be subject to mandatory redemption prior to maturity at a redemption price of 100% of the principal amount thereof plus interest accrued to the redemption date on October 1, 1998 and October 1, 2002, respectively and on each October 1 thereafter to maturity, in the following principal amounts in the years specified:

2001 Maturity	
Year	Amount
1998	$ 3,675,000
1999	4,000,000
2000	4,325,000
2001 (Maturity)	4,650,000

2007 Maturity	
Year	Amount
2002	$ 5,025,000
2003	5,425,000
2004	5,875,000
2005	6,325,000
2006	6,850,000
2007 (Maturity)	7,375,000

Optional Redemption

The 1980 Bonds maturing on or after October 1, 1991 are subject to redemption, at the option of the City, on and after October 1, 1990, in whole or in part on any interest payment date, at a redemption price of 100% of the principal amount thereof, together with accrued interest to the date of redemption.

All or any of the 1980 Bonds subject to call may be called for redemption at any one time. If less than all of the Bonds are redeemed at any one time, such Bonds shall be redeemed in inverse order of maturity and by lot within each maturity.

Special Refunding Call

If 1980 Bonds maturing after October 1, 1990 are defeased prior to October 1, 1983 in the manner described herein under the caption "Security for and Sources of Payment for the Bonds — Defeasance" and are called for redemption on October 1, 1990, then the redemption price for the 1980 Bonds so to be redeemed shall be as follows, plus accrued interest to the date of redemption:

Maturity October 1	Special Refunding Redemption Price
1991	100 %
1992	100
1993	100
1994	100
1995	100
1996	99¾
1997	98⅞
2001	96¾
2007	95

Notice of Redemption

The Resolution requires that notice of redemption of the 1980 Bonds be published in a newspaper of general circulation in the County of Los Angeles, California, and in a financial newspaper or journal of national circulation published in or near the City of New York, New York, said publications to be at least 30 days but not more than 60 days prior to the redemption date. If any of the 1980 Bonds designated for redemption be registered other than to bearer, the Registrar shall, on or before the dates of publication of said notices to such registered owners at the addresses appearing on the bond registry book.

SECURITY FOR AND SOURCES OF PAYMENT FOR THE BONDS

Pledge Under the Resolution

Pursuant to the City Charter, the Ordinance, which incorporates certain provisions of the Bond Law, and the Resolution, the Bonds are equally secured by a pledge, charge and lien upon the Gross Revenues of the Electric System. Gross Revenues are defined in the Resolution as rates, fees and charges for providing electric service to persons and real property and all other fees, rents and charges and other income derived by the City from the ownership, operation, use or services of the Electric System.

The General Fund of the City is not liable for the payment of the Bonds or their interest, nor is the credit or taxing power of the City pledged for the payment of the Bonds or their interest. The holder of the Bonds or coupons may not compel the exercise of the taxing power by the City or the forfeiture of any of its property. The principal of and interest on the Bonds and premiums upon the redemption of any thereof are not a debt of the City nor a legal or equitable pledge, charge, lien, or encumbrance upon any of its property, or upon any of its income, receipts, or revenues, except the Gross Revenues of the Electric System which are, under the terms of the Resolution, pledged to the payment of the Bonds.

Revenues and Flow of Funds Under the Resolution

Pursuant to the Resolution, all Gross Revenues are deposited with the City Treasurer to the credit of the Electric Revenue Fund. The City Finance Director shall allocate or transfer from the Electric Revenue Fund the following amounts in the order of priority as set forth below.

First, on or before the twentieth day of each calendar month so long as any of the 1980 Bonds are outstanding for deposit in the Bond Service Account (and, in the case of the 1972 Bonds, in the bond service fund created for that issue), the following: (i) one-sixth of the interest which will become due and payable on the outstanding Bonds within the next ensuing six months, except that for any interest payment due on or before April 1, 1984, the monthly sum allocated shall be the interest which will become due and payable less the amount of any funded interest placed in the IDC Account (see "Application of the 1980 Bond Proceeds") divided by the number of months remaining in said period, and (ii) one-twelfth of the principal amount which will mature and be payable on the outstanding serial Bonds within the next ensuing twelve months. Commencing on or before October 1, 2001 and on or before each October 1 thereafter so long as any of the term 1980 Bonds are outstanding, the Finance Director shall allocate to the Sinking Account established pursuant to the Resolution sums sufficient to call and redeem said term Bonds in accordance with the schedule set forth under "Description of the 1980 Bonds — Mandatory Redemption."

Second, to the Maintenance and Operation Account, amounts sufficient for the payment of the maintenance and operation expenses of the Electric System. Maintenance and operations expenses are defined in the Resolution as the reasonable and necessary current expenses of maintaining, repairing and operating the Electric System, including City administrative expenses directly attributable to Electric System functions, but excluding depreciation, interest and amortization, all computed in accordance with sound accounting principles and consistent with existing accounting practices of the City.

Third, on or before the twentieth day of each calendar month, for deposit in the Reserve Fund, the amount required, if any, for such Fund to equal the Maximum Annual Debt Service. (See "Reserve Fund" below).

Fourth, on or before the twentieth day of each calendar month, for deposit in the Renewal and Replacement Account, an amount equal to one percent (1%) of the Gross Revenues received in the preceding calendar month until a balance is established or reestablished therein equal to two percent (2%) of the depreciated book value of the land, general plant and equipment which constitute a portion of the Electric System. The moneys contained in such account may be used for extraordinary maintenance and repairs, renewals and replacements to the Electric System and may be transferred to the Bond Service Account to prevent default in payment of the principal and interest on outstanding Bonds. The balance in the Renewal and Replacement Account was $805,000 as of June 30, 1980. Since this account may be depleted at any time for the various purposes, no assurance can be given that moneys in said Account will be available at any particular time for transfer to the Bond Service Account.

All moneys remaining in the Electric Revenue Fund after the foregoing transfers have been made shall be transferred to the Electric System Surplus Revenue Fund. Such moneys have been pledged to the payment of principal of and interest on the outstanding 1976 Subordinated Bonds, the outstanding balance of which mature on December 1, 1980. As of the date hereof, the City has on deposit sufficient monies to pay at maturity the principal of and interest on the 1976 Subordinated Bonds. All moneys remaining in the Electric System Surplus Revenue Fund after satisfying the requirements of the resolution authorizing the issuance of the 1976 Subordinated Bonds shall, to the extent available, be transferred to the Construction Account on a monthly basis, up to and including the month of October, 1982 in an amount equal to 100% of the amount of income received during the preceding month from the investment of moneys in the Reserve Fund, and thereafter up to and including the month of December, 1983 in an amount equal to 50% of the amount of such income received during the preceding month, and any remaining moneys may be: (i) invested in any authorized investments, (ii) transferred to the Redemption Fund to be used for the redemption of Bonds which are subject to call or for purchase in the open market of any outstanding Bonds or (iii) used for any lawful purpose of the City.

Reserve Fund

The Resolution requires, in effect, that there be deposited into the Reserve Fund from the proceeds of the 1980 Bonds and any additional Bonds ranking on a parity with the Bonds the amount necessary so that such fund shall equal the Maximum Annual Debt Service calculated immediately after the issuance of such series of Bonds. Maximum Annual Debt Service is defined in the Resolution as the maximum sum obtained for any fiscal year of computation, or any fiscal year thereafter, by totaling the following for such fiscal year: (i) the principal amount of all outstanding serial Bonds payable in such fiscal year, (ii) the minimum principal amount of all outstanding term Bonds scheduled to be called and redeemed in such fiscal year, together with the premium thereon, if any be payable, and (iii) the interest which would be due during such fiscal year on the aggregate principal amount of Bonds which would be outstanding in such fiscal year if the Bonds are retired as scheduled, but deducting and excluding from such aggregate amount the amount of Bonds already retired.

The Reserve Fund is currently held and administered by the Bank of America NT & SA, the Fiscal Agent. After retirement of the 1972 Bonds, it will be held by the City Treasurer.

The Resolution requires that the Reserve Fund be maintained in an amount equal to Maximum Annual Debt Service. Moneys in the Reserve Fund shall be used solely for the purpose of paying the principal of and interest on the Bonds in the event that the moneys in the Bond Service Account or Sinking Account (or the bond service fund in the case of the 1972 Bonds) are insufficient therefor, and for that purpose the Fiscal Agent or the City Treasurer, as the case may be, shall withdraw and transfer moneys from the Reserve Fund to the Bond Service Account (or the bond service fund, in the case of the 1972 Bonds). Whenever moneys are withdrawn from the Reserve Fund an equal amount of moneys shall be placed in the Reserve Fund by transfers from the first available moneys in the Electric Revenue Fund.

As of the date hereof, the balance in the Reserve Fund is equal to the Maximum Annual Debt Service on all outstanding Bonds.

Rate Covenant

The City has agreed under the Resolution to prescribe, revise and collect such charges for the services and facilities of the Electric System which, after making allowances for contingencies and errors in the estimates, shall be at least sufficient to pay the following amounts in the order set forth; (i) the interest on and principal payments (including any Sinking Account payments) of the outstanding Bonds as they become due and payable, (ii) all current expenses for the necessary and reasonable maintenance and operation expenses of the Electric System as said expenses become due and payable, (iii) all payments required for compliance with the Resolution including transfers required to be made from the Electric Revenue Fund to other funds and accounts, (iv) all payments required for compliance with the resolution providing for the issuance of the 1976 Subordinated Bonds and (v) all payments required to meet any other obligations of the City which are charges, liens, encumbrances upon or payable from the revenues of the Electric System. Charges shall be so fixed that the Net Revenues shall be at least equal to the sum of 1.10 times the amounts payable under (i) above, provided that so long as any of the 1972 Bonds remain outstanding (the final scheduled maturity being July 1, 1992) such charges shall be so fixed that the Net Revenues shall at least equal 1.25 times the maximum amount payable under (i) above. Net Revenues are defined in the Resolution as the amount of Gross Revenues less the Maintenance and Operation Expenses.

Additional Debt

Under provisions of the Resolution, the City covenants that no additional indebtedness shall be incurred having any priority in payment of principal or interest out of the Gross Revenues of the Electric System over the Bonds.

Parity bonds may be issued to finance or refinance any repairs, improvements, enlargements or extensions of the Electric System and to refund any Bonds then outstanding, provided that the City covenants that, except for bonds issued to refund Bonds, no additional indebtedness evidenced by revenue bonds, revenue notes or any other evidences of indebtedness payable out of the Gross Revenues of the Electric System and ranking on a parity with the Bonds shall be created or incurred unless: (i) the City is not in default under the terms of the Resolution, (ii) the Net Revenues of the Electric System, calculated on sound accounting principles, as shown by the books of the City for each of the last two completed fiscal years prior to the adoption of the resolution approving the sale of such additional indebtedness as shown by an audit certificate or opinion of an independent certified public accountant or firm of certified public accountants employed by the City, plus, at the option of the City, the allowance for earnings described in the next paragraph, shall have amounted to at least 1.10 times the amount of principal and interest which will become due and payable or accrue in the fiscal year next succeeding the fiscal year in which such additional indebtedness is incurred on all Bonds and, so long as any of the 1972 Bonds remain outstanding (the final scheduled maturity being July 1, 1992), at least 1.25 times the Maximum Annual Debt Service in any fiscal year thereafter on all indebtedness to be outstanding immediately subsequent to the incurring of such additional indebtedness.

For the purpose of applying the restriction contained in this covenant, Gross Revenues may include an allowance for earnings arising from any increase in the charges made for service from the Electric System which has become effective prior to the incurring of such additional indebtedness but which, during all or any part of said last two completed fiscal years, was not in effect, in an amount equal to 95% of the amount by which the Gross Revenues would have been increased if such increase in charges had been in effect during the whole of said last two completed fiscal years, as shown by the certificate or opinion of an independent certified public accountant or firm of certified public accountants employed by the City.

In addition to the foregoing, under provisions of the resolution authorizing the issuance of the 1976 Subordinated Bonds, the City may not issue additional electric revenue bonds, whether parity or subordinated, unless (i) the City is not in default under the terms of the resolution authorizing the issuance of the 1976 Subordinated Bonds and (ii) the Net Revenues for each of the two preceding fiscal years shall have amounted to at least the amount of principal and interest which will become due and payable in the fiscal year next succeeding the fiscal year in which such additional indebtedness is incurred on all indebtedness payable out of the revenues of the Electric System.

Refunding Bonds

Parity bonds may also be issued to refund outstanding Bonds if, after giving effect to the application of the proceeds thereof either (i) Annual Debt Service will not be increased in any fiscal year in which Bonds (excluding such refunding parity bonds) not being refunded are to be outstanding, or (ii) the Net Revenues of the Electric System, calculated on sound accounting principles, as shown by the books of the City for each of the last two completed fiscal years prior to the adoption of the resolution approving the sale of such additional indebtedness as shown by an audit certificate or opinion of an independent certified public accountant or firm of certified public accountants employed by the City, plus, at the option of the City, the allowance for earnings described in the third paragraph under "Additional Debt", shall have amounted to at least 1.10 times the amount of principal and interest which will become due and payable or accrue in the fiscal year next succeeding the fiscal year in which such additional indebtedness is incurred on all Bonds so to be outstanding.

The City may issue parity bonds to refund the $6,200,000 outstanding 1972 Bonds without compliance with the foregoing tests.

In June 1980, the electorate of the City rejected a proposal to amend the City Charter to permit the issuance of refunding revenue bonds by the City without an additional election. The Department intends to seek resubmission of this proposal to the electorate. The City is unable to predict whether or when such proposal will be resubmitted or adopted or whether or when, if adopted, the authority to refund would be exercised.

Insurance

Under the provisions of the Resolution, the City covenants that it shall at all times maintain with responsible insurers all such insurance on the Electric System as is customarily maintained by similar utilities systems with respect to works and properties of like character against accident to, loss of or damage to such works or properties and loss of revenues insurance. If any useful part of the Electric System shall be damaged or destroyed such part shall be restored to use. The money collected from insurance against accident, loss or damage shall be used for repairing or rebuilding the lost, damaged or destroyed works and properties, and to the extent not so applied, shall be applied to the retirement of Bonds and for such purpose paid into the appropriate funds or accounts. The money collected from loss of revenues insurance shall be deposited in the Electric Revenue Fund.

The City shall also maintain with responsible insurers worker's compensation insurance and insurance against public liability and property damage to the extent reasonably necessary to protect the City and the Bondholders.

Notwithstanding the foregoing, the City may provide any insurance required by this covenant through a self-insurance program.

Other Covenants

Other covenants of the City under the Resolution are summarized below:

(a) The City will punctually pay, or cause to be paid, the principal of and interest on the Bonds and will make all payments into the Bond Service Account, the Sinking Account and the Reserve Fund in conformity with the terms of the Bonds and the Resolution.

(b) The City will commence the accomplishment of the purposes for which the Bonds are being issued and will complete such purposes with all practicable dispatch and in an economical manner.

(c) The City will pay and discharge all lawful claims and any taxes, assessments or other governmental charges lawfully levied or assessed against the Electric System or the Gross Revenues which, if unpaid, might impair the security of the Bonds.

(d) The City will operate the Electric System in an efficient and economical manner and preserve the Electric System in good repair and working order.

(e) The City will not (except as expressly permitted by the Resolution) mortgage, encumber, sell, lease, pledge, place a charge on or otherwise dispose of the Electric System or the Gross Revenues and will not enter into any agreement which impairs the operation of the Electric System or otherwise impairs the rights of the Bondholders with respect to the Gross Revenues or operation of the Electric System without making adequate provision to protect the rights of the Bondholders.

(f) The City will keep proper books of records and accounts of the Electric System in which complete and correct entries will be made of all transactions relating to the Electric System and will cause the books and accounts of the Electric System to be audited annually by an independent certified public accountant and furnish a copy of the audit report, upon request, to any Bondholder.

(g) The City will maintain and enforce valid regulations for the payment of bills for electric service and will permit no free connections with, or use and services of, the Electric System.

(h) The City will not invest the proceeds of the Bonds in a manner which would result in the Bonds constituting taxable "arbitrage bonds" within the meaning of Section 103(c) of the Internal Revenue Code of 1954 as amended, and the Income Tax Regulations issued thereunder.

Amendments to the Resolution

Any covenant of the City contained in the Resolution may be amended, waived or modified upon the consent of the holders of 60% of the bonds outstanding, exclusive of Bonds, if any, owned by the City. No such amendment, waiver or modification shall be made which will permit (i) a change in the maturity or term of redemption of the principal of any Bond or any installment of interest thereon or a reduction in the principal amount of or redemption price or redemption premium or rate of interest upon any Bond without the consent of the holder of such Bond; or (ii) a reduction of the percentage of the principal amount of Bonds the vote or consent of which is required to effect such amendment.

Investments

Moneys in the Construction Account, the IDC Account, the Bond Service Account, the Sinking Account and the Renewal and Replacement Account maintained by the City Treasurer and moneys in the Reserve Fund maintained by the Fiscal Agent may be invested in any obligations in which the City may lawfully invest its funds, provided that so long as any of the 1972 Bonds are outstanding, moneys in the Bond Service Account, the Sinking Account, the Reserve Fund and the Renewal and Replacement Account may be invested only in direct obligations or obligations guaranteed by the United States of America or Certificates of Deposit of recognized banks or trust companies fully secured by direct obligations of or obligations guaranteed by the United States of America.

Defeasance

The Resolution provides that 1980 Bonds shall no longer be deemed to be outstanding and unpaid if the City shall have made adequate provision for the payment, in accordance with the 1980 Bonds and the Resolution, of the principal and interest to become due thereon at maturity or upon call and redemption prior to maturity. Such provisions shall be deemed to be adequate if the City shall have irrevocably set aside, in a special trust fund or account, moneys which when added to the interest earned or to be earned from the investment or deposit thereof shall be sufficient to make said payments as they become due. Moneys so set aside may be invested in any direct obligations of, or obligations guaranteed by, the United States of America, in which the City may lawfully invest its money.

APPLICATION OF THE 1980 BOND PROCEEDS

The City estimates that the proceeds of the 1980 Bonds (excluding accrued interest) will be applied as follows:

For payment of the City's share of Project Construction Costs (1)	$50,250,000
For deposit in the Reserve Fund	8,000,000
For payment of costs of issuance (including a bond discount of $8,400,000)	8,950,000
For deposit in the IDC Account (2)	16,800,000
Total 1980 Bonds	$84,000,000

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(1) Includes an estimated $8,947,000 to be paid to Edison for interest charges prior to November 1, 1980. Excludes $4,172,000 of estimated investment income on Bond proceeds in the Construction Account, the IDC Account and the Reserve Fund.

(2) To pay 100% of the interest on the 1980 Bonds until October 1, 1982 and 50% of the interest on the 1980 Bonds thereafter until December 1, 1983.

Moneys in the Construction Account may be invested in any Authorized Investments, provided that the maturity or maturities thereof shall not be later than the date or dates on which moneys must be available to meet scheduled Construction Account expenditures. If any sum remains in the Construction Account after the full accomplishment of the purposes for which the 1980 Bonds were issued, it shall be transferred to and placed in the Electric Revenue Fund.

CITY OF ANAHEIM — THE ELECTRIC SYSTEM

History of the Electric System

As one of the first such municipally-owned systems in the State of California, the Electric System has been fundamentally a sub-transmission and distribution system, although it did generate all its own power from 1895 to 1916 and part of its own power from 1927 to 1930. The original City-owned generating plant was constructed in 1895 and consisted of a steam-driven generator of 500 lights capacity. By 1896, the maximum capacity of the generating plant had been reached and Anaheim voters passed authorization for bonds for the combined rebuilding of both the electric light plant and the City water system. In 1916 the City entered into an agreement to purchase electricity at wholesale rates from Edison rather than generate its own power. In 1934, the City, working with the Federal Public Works Administration, rebuilt and expanded the distribution system sufficiently to serve the needs of the citizens until the end of World War II.

The City has since continued to expand its distribution system to meet the growing demands of its customers. The Electric System serves the entire area within the City limits by receiving electricity at the 220 KV Lewis Receiving Station.

Estimated Financial Information

The Electric System, as well as the City, is currently undergoing its annual audit for the fiscal year ended June 30, 1980. Therefore, the financial information and statistics reflecting the status of the Electric System for the fiscal year ended June 30, 1980 and the ten months ended April 30, 1980 have been estimated by the Department and are preliminary and subject to adjustment.

Existing Facilities

The Electric System serves the entire area within the City limits of Anaheim, approximately 42 square miles. The principal facilities of the Electric System are transmission and distribution lines aggregating 1,211 circuit miles as of the fiscal year ended June 30, 1980. The Electric System comprises eight existing distribution substations with an additional distribution substation scheduled to be completed by late 1981. The following table sets forth statistical information relating to the facilities of the Electric System:

ELECTRIC SYSTEM STATISTICS

	Fiscal Year ended June 30				
	1980 (Unaudited)	1979	1978	1977	1976
Utility Plant (less accumulated depreciation)(1)	$40,262,000	$37,102,000	$32,711,000	$33,428,000	$[illegible]0,720,000
Transmission — 69 Kv Circuit Miles	51	44	44	44	44
Distribution					
Overhead Circuit Miles	871	871	870	869	863
Underground Circuit Miles	289	272	248	210	182
Transformer Capacity (in KVA)					
220 Kv to 69 Kv	840,000	840,000	840,000	840,000	840,000
69 Kv to 12 Kv	492,000	492,000	457,000	417,000	417,000
12 Kv to Customer	734,000	687,000	647,000	607,000	565,000

(1) During the year ended June 30, 1977, the City obtained an historical cost appraisal of its property, plant and equipment from a professional appraisal firm, Marshall and Stevens, Inc., which included a physical inventory of assets and a determination of their estimated remaining useful lives. Accordingly, utility plant (less accumulated depreciation) reflects adjustments at June 30, 1977 and 1976 and in subsequent years resulting from that appraisal. During the year ended June 30, 1979, the City elected to record its unamortized project costs as an other asset rather than utility plant. Accordingly, utility plant at June 30, 1980, 1979, and 1978 reflects this reclassification.

Power Supply

The electricity supplied to the City is purchased at wholesale rates from Edison or as economy energy from Nevada Power Company. In the fiscal year ended June 30, 1980, the Electric System purchased a total of 1,834,788,614 kilowatt hours of electricity for delivery to customers throughout the City. About 90 percent, or 1,657,880,614 kilowatt hours, was purchased from Edison. The remaining 10 percent, or 176,908,000 kilowatt hours, was purchased from Nevada Power Company.

On July 30, 1980, combined customer electric requirements created a new system peak demand of 408,000 kilowatts, up 12,000 kilowatts from the 1979-1980 peak.

The following table sets forth, in kilowatt hours of electricity, the total purchases of power and Electric System peak demand during the last 5 fiscal years.

TOTAL KILOWATT HOURS PURCHASED AND PEAK DEMAND

	Fiscal Year ended June 30				
	1980	1979	1978	1977	1976
From Edison(kWh)	1,657,880,614	1,501,098,304	1,472,686,902	1,305,991,471	1,541,60[illegible],451
From Nevada Power Company(kWh)	176,908,000	333,104,000	250,049,000	355,347,000	41,651,000
System Total	1,834,788,614	1,834,202,304	1,722,735,902	1,661,338,471	1,583,260,451
System peak demand (Kw)	396,000	395,600	347,600	328,000	330,400

The Electric System purchases power from Edison pursuant to the Integrated Operations Agreement whereby Edison agrees to furnish the capacity and energy necessary to meet the City's load, to the extent not provided by City integrated resources. The term of such agreement is 50 years commencing November, 1977. (See Appendix D — "Summary of the Integrated Operations Agreement"). In addition, the Electric System purchases power from Nevada Power Company pursuant to an agreement negotiated in 1976 which provides for purchase of a minimum of 250,000,000 kilowatt hours of economy energy per year for a minimum of four years. Proceeds of the 1976 Subordinated Bonds were used to fund such purchase. The Nevada Power agreement ends in December 1980. In June 1980, a subsequent agreement was executed between the City and Nevada Power Company providing for economy energy exchanges and energy banking arrangements. (See "Future Plans of the Electric System.")

The following table sets forth the annual power costs for purchased power during the last five fiscal years.

ANNUAL PURCHASED POWER COSTS

	Fiscal Year ended June 30				
	1980 (Unaudited)	1979	1978	1977	1976
Annual Power Costs	$71,930,000	$59,198,000	$51,747,000	$45,842,000	$39,347,000
Unit Power Costs (mills per kilowatt hour)	39.20	32.27	30.04	27.59	24.85

For a discussion of recent increases in power costs see "Operation and Maintenance of the Electric System."

Customers

The following tables set forth the average number of customers and total kilowatt hours sold during the last five fiscal years.

AVERAGE NUMBER OF CUSTOMERS

	Fiscal Year ended June 30				
	1980	1979	1978	1977	1976
Residential	72,426	70,386	68,380	66,957	63,772
Commercial	9,507	9,029	8,457	8,002	7,347
Industrial	451	438	407	383	365
Other	187	185	195	197	200
Total — all classes	82,571	80,038	77,439	75,539	71,684

TOTAL KILOWATT HOURS SOLD

(Millions of kWh)

	Fiscal Year ended June 30				
	1980	1979	1978	1977	1976
Residential	434	423	389	377	356
Commercial	391	379	357	338	307
Industrial	879	894	846	827	814
Other	30	31	29	33	34
Total Kilowatt Hours sold (1)	1,734	1,727	1,621	1,575	1,511

(1) The difference between the total kilowatt hours purchased and total kilowatt hours sold is due to system losses.

The following table sets forth the ten major commercial and industrial customers and the three major public agency customers of the Electric System in terms of total energy sales and total billings for the fiscal year ended June 30, 1980. The major commercial and industrial customers accounted for 19.8% of total energy sales and 18.2% of total annual billings of the Electric System. The largest of such industries accounted for 6.3% of total energy purchases and 5.7% of total annual billings, respectively, of the Electric System. The major public agencies noted below account for 4.2% of total energy purchases and 4.4% of total annual billings.

MAJOR ELECTRIC CUSTOMERS

Customer	Type of Business
Rockwell International Corporation	Aircraft, Aerospace and Electronics
Disneyland	Recreation and Entertainment
Delco-Remy Division, General Motors Corporation	Batteries
Pacific Telephone and Telegraph Company	Telephone Service
Wrather Corporation	Hotels, Restaurants, Shops (Includes Disneyland Hotel and Inn at the Park)
Northrop Electro-Mechanical Division, Northrop Corporation	Aerospace Electronics
Kwikset Division, Emhart Industries, Inc.	Residential Locksets and Powdered Metal Parts
Interstate Electronics Corp., Division of A-T-O, Inc.	Electronic Equipment
Monsanto Company—Packaging Division	Plastic Containers, Film and Sheeting
Lear Siegler, Inc.	Electronic Equipment

Public Agencies

City of Anaheim (including Water System and Street Lights)
Anaheim Union High School District
Anaheim Convention Center

Electric Rates and Charges

The City is obligated by its Charter and by the Resolution to establish rates and collect charges in an amount sufficient to service the Electric System's indebtedness and to meet its expenses of operation and maintenance, with specified requirements as to priority and coverage. (See "Rate Covenant" under the section "Security for and Sources of Payment for the Bonds".) Electric rates are fixed by the City Council and are not subject to regulation by the California Public Utilities Commission or by any other state agency.

Although its rates are not subject to approval by any federal agency, the City is subject to certain ratemaking provisions of the Public Utility Regulatory Policies Act of 1978. The City is operating in compliance with that Act. The City Charter requires that electric rates (as well as water rates) shall be based upon the cost of service to the various customer classes.

At present, the Electric System has 25 rate schedules in effect. The City provides no free electric service. All retail electric rates are subject to adjustment by an Energy Cost-Adjustment Billing Factor ("ECABF") applicable to each kWh to cover the variable cost of energy purchased from Edison above or below Edison's base rate. The ECABF is evaluated monthly and may be changed administratively. The ECABF effective May 1, 1980 (not reflected in the rate schedules below) is .572¢ for residential service (lifeline) and 1.485¢ for residential service (non-lifeline) and for all other classes of service. The following table sets forth the principal rate schedules for the residential, commercial and industrial customers.

RATE SCHEDULES FOR RESIDENTIAL, COMMERCIAL AND INDUSTRIAL CUSTOMERS

Type and Description of Service	Per Meter Per Month Charge
Domestic Service Single Family Customers	
Applicable where the customer is entitled to only the Basic Residential Use Lifeline allowance	
Customer Charge	$ 2.00
Energy Charge (to be added to Customer Charge):	
First 300 kWh, per kWh	3.912¢
All Excess kWh, per kWh	4.356¢
General Service Small Commercial and Industrial Customers	
Customer Charge	$ 4.50
Energy Charge (to be added to Customer Charge):	
All kWh, per kWh	5.820¢
General Service Large Commercial and Industrial Customers	
Demand Charge:	
First 200 KW or less of billing demand	$1,020.00
All Excess KW of billing demand, per KW	5.10
Energy Charge (to be added to Customer Charge):	
All kWh, per kWh	2.571¢

Electric System rates have been changed 12 times over the last five fiscal years, the current rates having become effective May 1, 1980. The following table sets forth the percentage changes in rates for the indicated customer classes.

AVERAGE PERCENTAGE INCREASE OR (DECREASE) IN ELECTRIC RATES

Effective Date	Overall System	Residential	Commercial	Industrial
July 15, 1975	(1.0)	—	(0.7)	(2.0)
February 4, 1976	5.1	1.9	4.9	7.7
July 1, 1976	(0.03)	—	(0.02)	(0.06)
September 1, 1976	5.0	5.0	5.0	5.0
December 29, 1976	(1.7)	(5.0)	(1.0)	—
July 1, 1977	5.7	2.5	7.0	7.0
September 21, 1977	13.5	13.0	9.5	15.5
June 1, 1979	5.3	(1.7)	3.9	9.3
September 1, 1979*	15.4	7.7	15.4	19.8
December 1, 1979*	10.3	6.1	10.1	12.5
March 1, 1980*	17.8	14.6	16.5	20.0
May 1, 1980*	(13.5)	(7.8)	(13.7)	(16.1)

* ECABF adjustment.

The Department is currently planning to present an application to the City Council for an increase in base electric rates to be effective January 1981. As of the date hereof, the expected overall increase in base electric rates to be requested is 10%. The ECABF will change from time to time.

The electric rates now in effect in the City compare favorably with those of other cities in the area. The following table sets forth electric billings of eight cities, of which three are served directly as retail customers of Edison. Edison sells power and energy wholesale to both Riverside and Anaheim, while Los Angeles, Pasadena and Glendale generate their own power.

ELECTRIC RATE COMPARISON BY MONTHLY BILL

(As of June 1, 1980)

	Residential			Commercial			Industrial	
	200 kWh	500 kWh	1100 kWh	500 kWh(1)	3000 kWh(1)	100 KW(2) 43,800kWh	200 KW(3) 87,600 kWh	5,000 KW(4) 2,555,000 kWh
ANAHEIM(5)	$ 10.97	$ 27.13	$ 62.18	$ 41.03	$ 223.65	$ 2,283.47	$ 4,573.06	$ 129,130.80
Santa Ana(6)	11.71	34.89	83.91	47.11	260.16	2,827.32	5,570.67	158,144.60
Fullerton(6)	11.71	34.89	83.91	47.11	260.16	2,827.32	5,570.67	158,144.60
Orange(6)	11.71	34.89	83.91	47.11	260.16	2,827.32	5,570.67	158,144.60
Riverside(5)	13.39	30.19	68.15	42.30	235.77	2,508.05	4,625.47	130,576.15
Los Angeles (DWP)(5)(7)	14.54	36.36	79.99	36.16	201.96	2,720.20	4,982.24	144,825.45
Pasadena(5)(7)	16.26	38.94	84.30	46.83	257.98	2,972.82	5,808.00	164,295.00
Glendale(5)(7)	21.02	48.30	101.46	59.05	319.55	3,806.28	7,442.56	203,878.00

(1) General Service — Single Phase less than 20 KW demand.

(2) Assumes 50% load factor.

(3) Assumes 60% load factor.

(4) Assumes 70% load factor.

(5) Served by municipal electric system.

(6) Served by Edison at retail.

(7) Generates own power supply.

The Electric System's Gross Revenues from the sale of electricity have increased from $48,509,000 in fiscal year ended June 30, 1976 to $90,461,000 in the fiscal year ended June 30, 1980, an increase of 86%. The following table sets forth such Gross Revenues during the last five fiscal years.

GROSS REVENUES FROM SALE OF ELECTRICITY

	Fiscal Year Ended June 30				
	1980 (Unaudited)	1979	1978	1977	1976
Residential	$21,708,000	$19,407,000	$17,289,000	$15,431,000	$14,330,000
Commercial	23,490,000	18,110,000	16,471,000	13,488,000	11,578,000
Industrial	43,699,000	32,091,000	29,178,000	23,619,000	21,616,000
Other	1,564,000	1,234,000	1,100,000	987,000	985,000
Total	$90,461,000	$70,842,000	$64,038,000	$53,525,000	$48,509,000

The table below sets forth the a' erage billing price per kilowatt hour of the various customer classes during the last five years.

AVERAGE BILLING PRICE PER KILOWATT HOUR

	Fiscal Year Ended June 30				
	1980 (Unaudited)	1979	1978	1977	1976
Residential	$.0501	$.0459	$.0445	$.0410	$.0403
Commercial	.0602	.0478	.0461	.0400	.0378
Industrial	.0497	.0359	.0345	.0286	.0266
Other	.0523	.0393	.0376	.0300	.0293
Average All Classes Combined	.0522	.0410	.0395	.0340	.0321

Operation and Maintenance of the Electric System

A staff of approximately 195 persons is employed by the City to operate and maintain the Electric System. During the fiscal year ended June 30, 1980 the total operating expenses of the Electric System were $78,250,000 excluding depreciation. Operating expenses have increased from $43,215,000 in the fiscal year ended June 30, 1976 to $78,250,000 in fiscal year ended June 30, 1980, an increase of approximately 81%. While system growth and general inflation has had some impact on operating expenses, the impact of increased prices paid by Edison for imported low sulphur fuel oil on Edison's resale power rates has been the primary cause of increased operating expenses. Edison's wholesale electric rates were increased 2.8% on August 16, 1980 subject to refund. Purchased po·.er expense increased from $39,347,000 for fiscal year ended June 30, 1976 to $71,930,000 for fiscal year ended June 30, 1980, an increase of apr.. imately 83%.

The following table sets forth the Operating Expenses of the Electric System (excludi..g depreciation) during the last five fiscal years.

OPERATING EXPENSES (EXCLUDING DEPRECIATION)

	Fiscal Year Ended June 30				
	1980 (Unaudited)	1979	1978	1977	1976
Cost of Purchased Power	$71,930,000	$59,198,000	$51,747,000	$45,842,000	$39,347,000
Maintenance and Operations	6,320,000	5,693,000	4,658,000	4,463,000	3,868,000
Total	$78,250,000	$64,891,000	$56,405,000	$50,305,000	$43,215,000

Accounting records, financial transactions, and billin., including all billing and accounting for the Electric System, are computerized. Annual audits of the City's electric and water utilities are made separately by the City's independent certified public accountant. The audits are made simultaneously with the audits of the non-utility .. ancial activity of the City.

Prior to July 1971, the Electric System was treated, for accounting purposes, as an account in the City's General Fund. Since July 1971, funds of the Electric System have been separated from the General Fund of the City and the books and records are maintained separate and apart from all other funds and accounts of the City.

Transfers to the General Fund of the City of surplus funds of the Electric System (after payment of operation and m. intenance expenses and debt service on the Bonds) are made annually. Prior to June 30, 1977, there were no restrictions on the maximum amo. nt that could be transferred annually from the Electric Utility Fund to the General Fund of the City. The amount of these transfers, to and i-cluding the year ended June 30, 1977, was determined by the City Council through the budgeting process. As a result of an amendment to the City Charter, approved by the voters on November 11, 1976, annual transfers after June 30, 1977 were limited to a percentage of gross utility fund revenues of the prior fiscal year remaining after payment of debt service payments on outstanding Bonds, operation and maintenance expenses and other payments required by the Resolution. In fiscal year 1979, the maximum amount that could be transferred was 6% of the prior year's adjusted gross revenue and all subsequent transfers are limited to 4%. Such transfers may be further limited as a result of the enactment of Article XIIIB of the California Constitu[illegible] (See "Constitutional Limitation on Governmental Spending" below and "Constitutional Amendments Affecting City Revenues" in Appendix H).

For further information concerning the Electric System's financial position, see the audited financial statements for the fiscal years ended June 30, 1979 and 1978 and the unaudited financial statements for the ten months ended April 30, 1980 and 1979 attached hereto as Appendices F and G, respectively.

Outstanding Debt Service Requirements

The following table indicates the actual debt service on the outstanding Bonds of the Electric System and debt service on the 1980 Bonds, at interest rates as set forth on the cover page of this Official Statement.

DEBT SERVICE REQUIREMENTS*

Fiscal Year Ending June 30	Outstanding 1972 Bonds and 1976 Bonds			1980 Bonds			Total Debt Service
	Principal	Interest	Total	Principal	Interest**	Total	
1981	$ 425,000	$ 639,000	$ 1,064,000		$ 3,360,000	$ 3,360,000	$ 4,424,000
1982	450,000	607,375	1,057,375		6,720,000	6,720,000	7,777,375
1983	475,000	575,500	1,050,500		6,720,000	6,720,000	7,770,500
1984	500,000	546,675	1,046,675		6,720,000	6,720,000	7,766,675
1985	525,000	522,975	1,047,975	$ 1,250,000	6,670,000	7,920,000	8,967,975
1986	550,000	497,125	1,047,125	1,375,000	6,565,000	7,940,000	8,987,125
1987	600,000	468,913	1,068,913	1,450,000	6,452,000	7,902,000	8,970,913
1988	625,000	438,150	1,063,150	1,600,000	6,330,000	7,930,000	8,993,150
1989	650,000	405,512	1,055,512	1,700,000	6,198,000	7,898,000	8,953,512
1990	700,000	371,100	1,071,100	1,850,000	6,056,000	7,906,000	8,977,100
1991	750,000	332,925	1,0[illegible]2,925	2,000,000	5,902,000	7,902,000	8,984,925
1992	775,000	292,450	1,0[illegible],450	2,150,000	5,736,000	7,886,000	8,953,450
1993	825,000	260,750	1,08[illegible]750	2,325,000	5,557,000	7,882,000	8,967,750
1994	175,000	245,300	42[illegible]300	2,525,000	5,363,000	7,888,000	8,308,300
1995	200,000	234,975	43[illegible]75	2,725,000	5,153,000	7,878,000	8,312,975
1996	225,000	223,175	448[illegible]75	2,925,000	4,927,000	7,852,000	8,300,175
1997	250,000	209,675	459[illegible]75	3,175,000	4,683,000	7,858,000	8,317,675
1998	275,000	194,675	4[illegible]75	3,425,000	4,4[illegible]9,000	7,844,000	8,313,675
1999	300,000	178,17[illegible]	478,175	3,675,000	4,13[illegible],000	7,810,000	8,288,175
2000	325,000	160,175	485,175	4,000,000	3,828,000	7,828,000	8,313,175
2001	350,000	140,350	490,350	4,325,000	3,495,000	7,820,000	8,310,350
2002	350,000	119,000	469,000	4,650,000	3,136,000	7,786,000	8,255,000
2003	375,000	97,650	472,650	5,025,000	2,749,000	7,774,000	8,246,650
2004	400,000	74,400	474,400	5,425,000	2,331,000	7,756,000	8,230,400
2005	400,000	49,600	449,600	5,875,000	1,879,000	7,754,000	8,203,600
2006	400,000	24,800	424,800	6,325,000	1,391,000	7,716,000	8,140,800
2007				6,850,000	864,000	7,714,000	7,714,000
2008				7,375,000	295,000	7,670,000	7,670,000
	$11,875,000	$7,910,400	$19,785,400	$84,000,000	$127,634,000	$211,634,000	$231,419,400

* The table excludes the currently outstanding $2,225,000 of 1976 Subordinated Bonds due December 1, 1980. The City has on hand funds sufficient to pay such bonds together with interest thereon.

** Interest capitalized on 100% of the interest on the 1980 Bonds until October 1, 1982 and 50% of the interest on the 1980 Bonds thereafter until December 1, 1983.

Coverage of Debt Service

The following table shows the historical coverage of debt service by the Net Revenues of the Electric System for the last five fiscal years as calculated in accordance with the flow of funds in the Resolution.

SUMMARY OF COVERAGE OF DEBT SERVICE
(000)

	Fiscal Year Ended June 30				
	1980 (Unaudited)	1979	1978	1977	1976
Operating Revenues:					
Sales of Electric Energy	$90,461	$70,842	$64,038	$53,525	$48,509
Other Operating Revenues (including interest income)	2,074	1,200	1,261	1,141	784
Total Operating Revenues	$92,535	$72,042	$65,299	$54,666	$49,293
Operating Expenses (excluding depreciation):					
Cost of Purchased Power	$71,930	$59,198	$51,747	$45,842	$39,347
Maintenance and Operations	6,320	5,693	4,658	4,463	3,868
Total Operating Expenses	$78,250	$64,891	$56,405	$50,305	$43,215
Net Revenues	$14,285	$ 7,151	$ 8,894	$ 4,361	$ 6,078
Debt Service Requirements (excluding Subordinated Bonds)	$ 1,069	$ 1,072	$ 1,072	$ 1,072	$ 644
Times Debt Service Covered By Net Revenues	13.4	6.7	8.3	4.1	9.4

Energy Conservation

Since the OPEC Oil Embargo, industry and large commercial customers generally have made the greatest strides in reducing electric energy consumption.

Through printed materials mailed with utility billings, the Department continues to promote consumer awareness of the need for conservation measures and effective steps which can be taken by individual customers to reduce their electric use. The Department emphasized its commitment to effective conservation programs with the establishment of the Conservation Services Division.

The Electric System is subject to the National Energy Conservation Policies Act, and is in the process of implementing conservation programs required by the Act. A residential conservation service plan has been prepared and submitted in a timely manner to the Department of Energy for approval as required by the Act.

Constitutional Limitation on Governmental Spending

Article XIIIB of the California Constitution (adopted by a vote of the people in November, 1979) limits the annual appropriations of State and local governmental entities to the amount of appropriations of the entity for the prior fiscal year, as adjusted for changes in the cost of living, changes in population and changes in services rendered by the entity.

Pending clarification of certain of its provisions by the courts, or by the Legislature, the full impact of Article XIIIB on the amounts and uses of moneys to be deposited in the Electric Revenue Fund is not clear. However, to the extent moneys in the Electric Revenue Fund are used to pay the costs of maintaining and operating the Electric System and debt service on the Bonds (including the funding of the Reserve Fund, as required by the Resolution), such moneys should not, under the terms of Article XIIIB as supplemented by recent legislation and based upon the official ballot argument supporting the measure at the November 1979 election, be held to be subject to the appropriation limit.

SUMMARY PROJECTION OF OPERATING RESULTS OF THE ELECTRIC SYSTEM

Based on the forecast of power costs by the Consulting Engineer and on certain data supplied by the City and certain considerations and assumptions (see "Considerations and Assumptions of the Consulting Engineer"), the Consulting Engineer has prepared a projection of operating results of the City's Electric System for the fiscal years ending 1981 through 1985. Increases in revenue requirements are projected beyond those generated by the City's existing rates. The required revenues are based on covering projected operating expenses, debt service on the 1980 Bonds and previous bonds issued by the City, and on meeting the City's projected capital improvement program and other non-operating financial commitments. The additional revenues required are primarily to meet future capital improvements and escalating purchased power costs from Edison.

PROJECTED OPERATING RESULTS

(000)

	Fiscal Year Ending June 30				
	1981	1982	1983	1984	1985
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1980 Average Charges	$100,280	$105,217	$110,864	$116,545	$121,731
Additional Revenues Required (1)	11,240	32,992	55,454	85,775	110,510
Subtotal	$111,520	$138,209	$166,318	$202,320	$232,241
Miscellaneous Operating Revenue (2)	274	263	275	287	303
Interest Income (3)	723	922	1,116	1,359	1,576
Interest Income (Reserve Fund) (4)	478	727	727	727	727
Total Estimated Gross Revenues	$112,995	$140,121	$168,436	$204,693	$234,847
Operating Expenses:					
Power Production — San Onofre Units 2 and 3	$ 0	$ 692	$ 2,179	$ 3,885	$ 4,684
Purchased Power — Edison	96,632	114,502	139,153	169,473	195,265
Other Operation and Maintenance Expense (2)	9,443	10,294	11,431	12,303	13,205
Total Estimated Operating Expenses Excluding Depreciation and Amortization	$106,075	$125,488	$152,763	$185,661	$213,154
Total Estimated Net Revenues	$ 6,920	$ 14,633	15,673	$ 19,032	$ 21,693
Debt Service on the Bonds:					
Outstanding Bonds	1,064	1,057	1,050	1,047	1,048
The 1980 Bonds (5)	0	0	2,520	6,258	7,989
Total Debt Service on the Bonds	$ 1,064	$ 1,057	$ 3,570	$ 7,305	$ 9,037
Balance for Other Purposes (6)	$ 5,856	$ 13,576	$ 12,103	$ 11,727	$ 12,656
Debt Service Coverage by Net Revenues on the Bonds (7)	6.50	13.84	4.39	2.61	2.40

(1) Additional revenues required primarily to meet costs of future capital improvements and escalating purchased power costs from Edison.

(2) Estimated by the City.

(3) Estimated by the City. Includes interest earnings on existing Reserve Fund at an assumed 8.5% interest rate and interest earnings on other funds at an assumed 7% interest rate.

(4) For the 1980 Bonds only at an assumed investment rate of approximately 9.0%.

(5) Based on 100% of interest capitalized to October 1, 1982; 50% of interest capitalized to December 1, 1983.

(6) Includes, among other things, payments to renewal and replacement account as required by the Bond Resolution, payments to the general fund, funds for Electric System capital improvements and a payment of $2,280,000 in 1981 on subordinated bonds. In addition the balances shown include interest earnings on the Reserve Fund expected to be available for transfer to Construction Account:

Year Ending June 30	1981	1982	1983	1984
Interest Earnings (000)	$478	$727	$452	$148

(7) Ratio of total estimated Net Revenue to total debt service on the Bonds.

THE PROJECT

General

Pursuant to a Settlement Agreement dated August 4, 1972 with Edison, the City was granted the right to acquire a 1.66% ownership interest in the Project, with Edison providing the necessary transmission services to the City to deliver the output of the Project to the Electric System. Edison has signed and the City upon delivery of the Bonds will sign the San Onofre Units 2 and 3 Participation Agreement (the "Participation Agreement") with Edison which sets forth the terms and conditions under which the City will participate in the ownership and output of the Project and the Transmission Service Agreement (the "Transmission Service Agreement") whereby Edison agrees to provide transmission of the City's share of the output of the Project to the City's point of delivery at the Lewis Substation. The City has also signed an Integrated Operations Agreement (the "IOA") and will sign upon delivery of the 1980 Bonds a Supplemental Agreement for the integration of Anaheim's [illegible]itlements in San Onofre Units 2 and 3 (the "Supplemental Agreement") with Edison which provides, among other things, for the operation of the Project by Edison for the benefit of the City. Under the IOA, Edison will continue to supply the City's power and energy requirements over and above the capability of the City's share of the Project and any future City owned resource and credit the City on its monthly billing statements for the pow[illegible] energy generated by such resources that are integrated with Edison's resources. The City ar[illegible] have agreed in the Supplemental Agreement that the Project will be included as an integrated [illegible]urce pursuant to the IOA. (For a summary description of the Participation Agreement, the Transmission Service Agreement, the IOA and the Supplemental Agreement, see Appendices B, C, D and E attached hereto.)

Description of the Project

The San Onofre Nuclear Generating Station consists of two 1,100-MWe nuclear generating units currently under construction and an existing nuclear generating unit No.1 (not a part of the Project) rated at 450-MWe. The station is located on an 84-acre site approximately three miles south of San Clemente, California and within the U.S. Marine Corps Base at Camp Pendleton. Except for certain common facilities shared with Unit 1, the Project consists of the two units under construction. These units, Units 2 and 3, are essentially identical in design and will share certain common facilities including the control room and certain other facilities.

The nuclear steam supply systems for the Project, supplied by Combustion Engineering, Inc., are closed-cycle pressurized water reactor systems rated at 3,410 MWt each. The turbine generators are tandem compound units supplied by GEC Turbine Generators, Ltd. (formerly English Electric). The main condensers are being supplied by Ingersoll Rand and will be cooled by circulating seawater obtained through large intake lines extending out 5,200 feet into the ocean.

The main generators are rated at 1,312,950 kVA. The main transformers will consist of banks of three single-phase transformers designed to step-up the output voltage of each generator to 220 kV for interconnection into the facilities of Edison's transmission network.

The Project is being designed and the construction is being managed by the Bechtel Power Company for Edison. Edison is managing the start-up program and will operate the two units upon receiving a commercial operating license.

It is currently planned that the Project will be owned as tenants-in-common by the following investor owned and publicly owned utilities:

Participants	Ownership Interest
Edison	76.55%
San Diego	20.00
City of Riverside	1.79
City of Anaheim	1.66
Total	100.00%

Estimated Financing Requirements for the Project

The following table shows the estimated cost of constructing and financing the Project:

	Total Project(1)	City's Share
Land and Land Rights	$ 3,270,000	$ 54,000
Structures and Improvements	680,928,000	11,304,000
Reactor Plant Equipment	811,009,000	13,463,000
Turbogenerator	460,008,000	7,636,000
Accessory Electrical Equipment	195,485,000	3,245,000
Miscellaneous Power Plant Equipment	58,500,000	971,000
Subtotal Direct Construction Costs	$2,209,200,000	$36,673,000
Ad Valorem Taxes(2)		648,000
Nuclear Fuel(1)		4,798,000
City's Contingency(3)		3,356,000
Total Construction Costs		$45,475,000
Interest Payable To Edison(4)		8,947,000
Reserve Fund(5)		8,000,000
Interest Funded During Construction(6)		16,800,000
Financing Costs(7)		8,950,000
Gross Requirements		$88,172,000
Less: Interest Income(8)		4,172,000
Net Financing Requi:ements		$84,000,000

(1) Estimated by Edison.
(2) Estimated share of tax to be paid by City.
(3) Additional contingency not included in Edison's estimated costs to allow funds for uncertainties in the licensing schedule and possible additional design changes in the future.
(4) City's share of estimated interest costs paid by Edison through October 1, 1977 and City's interest costs at 9% per year on funds expended by Edison from November 1, 1977 to October 31, 1980.
(5) Approximate maximum annual debt service.
(6) Based on 8.0% annual interest rate on the 1980 Bonds. 100% of the interest on the 1980 Bonds is capitalized until October 1, 1982 and 5 of the interest on the 1980 Bonds is capitalized until December 1, 1983.
(7) Includes maximum allowable Bond discount of $8,400,000 and costs of issuance of $550,000.
(8) From temporary investment at an assumed interest rate of 7% of the 1980 Bond proceeds deposited in the Construction Account and the IDC Account. Also included are 100% of investment income on the Reserve Fund until October, 1982 and 50% of such interest income until December, 1983 estimated at a rate of approximately 9.0%. The interest earnings on the Reserve Fund are presumed to reach the Electric System Surplus Revenue Fund and as such, subject to the pledge of the 1976 Subordinated Bonds, are required by the Resolution to be deposited in the Construction Account to the extent not otherwise needed in accordance with such Resolution.

Edison has estimated that certain design changes resulting from the accident analysis of the Three Mile Island Unit No. 2 ("TMI-2") will result in an additional $30,000,000 plus overhead costs to the Project and have included such costs in their estimate of the total direct construction costs.

Status and Schedule of Construction

Construction of Unit 2 began in March 1974 after receipt of a construction permit from the NRC in October 1973, and the major construction of Unit 3 started in June 1975. Fuel loading for Unit 2 is scheduled for the second quarter of 1981 with commercial operation in December 1981. Fuel loading for Unit 3 is scheduled for the third quarter of 1982 with commercial operation scheduled for February 1983. An operating license must be issued for each unit before fuel loading may begin for that unit. As of June 27, 1980, Edison has stated that the construction of Unit 2 was approximately 93% complete and Unit 3 was approximately 63% complete.

Various locals of the International Brotherhood of Boilermakers have begun work stoppages at projects in certain western states, after the expiration on September 30, 1980 of their regional contract. Local 92 of the Boilermakers halted work on the Project on October 7, 1980 and, with other trade unions honoring the stoppage, construction work on the Project has stopped. The City is unable to predict the duration of the stoppage and therefore the impact the stoppage will have on the construction schedule or cost of the Project.

Nuclear Fuel

The nuclear fuel cycle consists of four basic elements prior to insertion of the fuel assemblies in a nuclear reactor. These elements include acquisition of uranium concentrates, conversion of the uranium concentrates to uranium hexafluoride, enrichment of the uranium hexafluoride and fabrication of the enriched uranium into fuel assemblies. After the fuel has been used in the reactor, it is removed for reprocessing or disposal.

The following table shows the amount of coverage of the necessary materials and services Edison has acquired for the Project:

	Unit 2		Unit 3	
	Full Coverage Through	% Coverage Through 1990	Full Coverage Through	% Coverage Through 1990
Uranium	1985	85	1985	52
Conversion	1990	100	1990	100
Enrichment	2009	100	2009	100
Fabrication	1984	25	1985	55
Storage	1991	100	1992	100

At the present time, no operating facilities for the reprocessing of spent fuel are available, and in April 1977 the President of the United States announced an indefinite deferral of reprocessing spent fuel and the use of plutonium. In October 1977, the United States Department of Energy (the "DOE") announced its intent to accept and take title to spent fuel from utilities upon payment of a one time storage fee. The details of this DOE program are currently being formulated. Edison is providing on-site spent fuel storage capacity for the Project estimated to be sufficient to accommodate storage of the discharges of all spent fuel from Unit 2 through 1991 and from Unit 3 through 1992. By then it is assumed that an appropriate program will have been implemented to accept spent fuel for placement in a suitable repository.

Permits and Approvals

Edison has informed the City that all major required permits, except an operating license, have been granted. Edison's current schedule anticipates that the operating license will be received from the NRC in sufficient time to meet the projected fuel loading and start up schedules. However, petitions have been granted to certain adverse parties to intervene in the operating license proceedings. The City cannot predict what impact, if any, such intervention will have upon the timing of issuance of, or the conditions included in, the operating license. (See "Regulatory Matters").

City's Future Power Supply Requirements and Future Power Supply Resources

Pending further development of other generating resources the City may acquire (see "Other Projects of the Electric System"), it is assumed that the City's power requirements not produced by the Project will be met by purchases from Edison through the IOA. The compound annual growth rate for peak demand is 3.3% and for energy requirements is 3.5% for the ten years projected. The following table shows the annual peak and energy requirements as estimated by the City and the estimated amounts of power and energy expected to be supplied from the Project and from Edison purchases.

Fiscal Year Ended June 30	Peak (MW)			Energy (Millions of kWh)		
	Requirements	Purchased from Edison	Capacity from the Project	Requirements	Purchased from Edison	Generated by the Project
1981	415.0	415.0	—	1,905	1,905	—
1982	428.0	428.0	—(1)	1,999	1,967	32
1983	450.0	435.5	14.5(1)	2,107	2,005	102
1984	473.0	444.1	28.9	2,215	2,048	167
1985	496.0	467.1	28.9	2,313	2,114	199
1986	515.0	486.1	28.9	2,399	2,187	212
1987	532.0	503.1	28.9	2,478	2,256	222
1988	547.0	518.1	28.9	2,551	2,329	222
1989	562.0	533.1	28.9	2,622	2,400	222
1990	576.0	547.1	28.9	2,688	2,466	222

(1) The City will receive certain capacity credits for the Project for the years ending June 30, 1982 and

1983 from Edison, however, not all capacity from the City's share of the Project will be available to meet the City's forecast peak load for those years.

Estimated Cost of Power from the Project

The following table shows the estimated annual costs of power from the Project as it is delivered to the City's system for the years 1982 through 1990 based on Edison's estimate of energy generation by the Project.

ESTIMATED ANNUAL COST TO THE CITY OF POWER FROM THE PROJECT
($000)

	Fiscal Year Ending June 30								
	1982	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**
Interest and Amortization(1)	—	2,520	6,258	7,989	7,969	7,986	7,973	7,977	7,982
Land Easement(2)	1	2	3	3	4	4	4	4	4
Operation and Maintenance(2)	245	500	925	1,337	1,471	1,612	1,767	1,937	2,123
Administrative and General(2)	143	299	375	416	452	492	535	582	634
Nuclear Insurance(2)	48	115	157	174	190	206	224	244	266
Nuclear Fuel(3)	103	837	1,763	2,052	1,890	2,347	2,889	2,493	2,588
Renewals and Replacements(4)	107	270	412	445	481	519	561	606	654
Taxes(5)	5	56	107	112	112	112	112	112	112
Transmission(6)	40	100	143	145	147	149	152	154	156
Subtotal	692	4,699	10,143	12,673	12,716	13,427	14,217	14,109	14,519
Less: Interest Earnings(7)	—	275	579	727	727	727	727	727	727
Total	692	4,424	9,564	11,946	11,989	12,700	13,490	13,382	13,792
Energy Delivered (Millions of kWh)(8)	32	102	167	199	212	222	222	222	222
Cost (Mills per kWh)	21.6	43.4	57.3	60.0	56.6	57.2	60.8	60.3	62.1

(1) Based on 100% of interest capitalized until October 1, 1982 and 50% of the interest capitalized until December 1, 1983. Remaining interest to be paid from revenues.

(2) As estimated by Edison.

(3) Based on Edison nuclear fuel costs.

(4) Estimated at 1% of capital costs and escalated at 8% per year.

(5) Based on the City's share of ad valorem taxes at the time of acquiring its ownership share.

(6) Based on the Transmission Service Agreement.

(7) Earnings on the Reserve Fund not deposited in the Construction Account at an assumed interest rate of approximately 9%.

(8) Computed as the City's share of estimated total generation at the Project site, less energy transmission losses estimated at approximately 1%.

Considerations and Assumptions of the Consulting Engineer

The estimates and projections of the Consulting Engineer are based upon, among other things, information from Edison, as manager of the Project and from the City. Such estimates and projections are also based upon the considerations and assumptions reflected in "Appendix A — Consulting Engineer's Report."

Conclusions of the Consulting Engineer

R. W. Beck and Associates, Consulting Engineer to the City, has prepared "The Consulting Engineer's Report" concerning the Project. Based upon the studies, investigations, analyses and assumptions set forth and the information supplied by the City and Edison with respect to the proposal by the City to acquire an ownership interest in the Project, the Consulting Engineer is of the opinion that:

1. The acquisition of an ownership interest in the Project by the City and the operation of the Project under the provisions of the IOA will provide the City with an economical long-range source of power that will result in lower power supply costs than would result from the continued purchase of all its power requirements from Edison.

2. The forecasted overall revenue requirements from the sale of electricity by the City are reduced by the City acquiring an ownership share in the Project rather than continuing to purchase all of its power requirements from Edison.

3. The estimated cost of power from the Project compares favorably with forecast purchase power rates from Edison and with available cost projections of other generating resources potentially available to the City in the 1980's.

4. The construction cost estimates by Edison for the Project are comparable with the costs expected for similar projects being developed within the same time frame.

Certain Factors Affecting the Electric Utility Industry and Effects of the Three Mile Island Accident

The electric utility industry is currently experiencing problems in a number of areas including, among others, the effects of inflation upon the costs of operations and construction, availability and high cost of capital, availability and increased cost of fuel for the generation of electric energy, long construction periods for new generating units, licensing and other delays affecting the construction of new facilities, and compliance with environmental regulations and Federal energy legislation, including the National Energy Act of 1978. The City is unable to predict the extent to which the Electric System will be affected by such factors.

In addition, following the accident at TMI-2, the NRC has undergone a reorganization and an interruption of its licensing efforts. The licensing requirements for nuclear plants are continually being re-evaluated in light of the TMI-2 accident which has resulted in some uncertainty in the licensing schedules for all plants approaching completion of construction.

The TMI-2 accident analysis of the NRC has resulted in additional design change requirements by the NRC. Edison has estimated that these design changes will result in an additional $30,000,000 plus overhead costs to the Project and have included such costs in their estimate. There is the possibility that additional design changes may be required in the future.

REGULATORY MATTERS

The California Public Utilities Commission has issued an order authorizing Edison to transfer an ownership interest in the Project to the City. It is not necessary that either the Federal Energy Regulatory Commission ("FERC") or the California Energy Commission approve the transfer of an ownership interest to the City. The City has complied with the California Environmental Quality Act insofar as it is applicable to the transfer of an ownership interest to the City. To the extent that additional permits or approvals (other than the NRC operating permit discussed below) may be required, the City believes that such will be obtained in due course.

Nuclear Regulatory Commission

The Atomic Energy Act (42 USC 2131; Title 10 CFR 50.10(a)) provides that it is unlawful for any person within the United States to transfer or receive in interstate commerce, manufacture, produce, transfer, acquire, possess, use any utilization of production facility equipment except under and in accordance with a license issued by the NRC. A Construction Permit was issued on October 18, 1973 to Edison and San Diego. Therefore, while the City will not operate the facility, it has been concluded that it will be necessary for the Construction Permit to be amended by adding the City as an owner thereto. On July 19, 1979, Edison, San Diego, Anaheim and Riverside filed an Application with the NRC to amend the Construction Permit. On August 5, 1980, the NRC approved the Application to amend the Construction Permit thereby adding Anaheim and Riverside as owners of the Project.

Edison and San Diego have applied for an Operating Permit. Petitions to Intervene have been granted to several adverse parties. Primary issues raised relate to seismic and geologic conditions and to emergency planning. As part of the proceedings, the United States Geological Survey is preparing a report on seismic and geologic matters for submission to the NRC for its consideration. Edison has advised the City that, based on studies conducted by or on behalf of Edison, it believes that the Project is designed to be able to withstand maximum adverse seismic conditions it considers credible for the Project area. Discovery has commenced and is presently proceeding. It is anticipated that the Atomic Safety and Licensing Board will set dates for hearings on this matter in early 1981. The Licensing Board has indicated that when the Cities acquire their ownership interest in the Project they will be consolidated with applicants Edison and San Diego for the Operating Permit proceedings. An Operating Permit has not yet been granted for this facility. It will be necessary for the City to apply for, and be granted, an Operating Permit for Units 2 and 3. It is not anticipated that the City will have any different problems with obtaining an Operating Permit than will Edison and San Diego.

FUTURE PLANS OF THE ELECTRIC SYSTEM

The City currently purchases all of its firm electrical power requirements from Edison at Edison's wholesale rates and purchases certain amounts of economy energy, pursuant to an Economy Energy Agreement dated May 25, 1976 from Nevada Power Company. The Economy Energy Agreement will terminate in December 1980. In June 1980, the City and Nevada Power Company executed an agreement which provides for economy energy exchanges and energy banking arrangements. In addition, in June 1980, the City and the DOE executed a letter agreement whereby the City may purchase fuel replacement interruptible energy from relatively low cost DOE resources when such energy is available.

The increased cost of fuel oil has resulted in higher wholesale power costs to the City. The cost of electricity purchased by the City increased by 22% for the fiscal year ended 1980. In order to lessen the impact of the continually rising power costs, the Department is actively pursuing alternate sources of power including joint participation in coal and other electric generating projects.

OTHER PROJECTS OF THE ELECTRIC SYSTEM

In addition to the Project, the City has an ongoing program to investigate other potential power supply resources which could be used to serve a portion of its requirements which are currently being purchased from Edison. Of these potential resources, the most definitive is the Intermountain Power Project ("IPP") to be located in Southwest Utah.

Intermountain Power Project

In 1974, the City entered into a Membership and Study Agreement with the California cities of Riverside, Burbank, Glendale, Pasadena and the Department of Water and Power of The City of Los Angeles ("LADWP") and with the Intermountain Consumer Power Association, composed of a group of Utah municipalities and rural electric cooperatives. The purpose of the membership and study agreement was to investigate the feasibility of constructing and operating the project. The proposed project is a 3,000-megawatt coal-fired electric-generating plant consisting of four 750-megawatt generators, to be located in

Southwest Utah. The presently projected commercial operation date of the first unit is July 1986 with other units following at one-year intervals. A feasibility study has been completed by LADWP pursuant to an agreement between IPP and LADWP.

In May 1977, several Utah municipalities, which are members of the Intermountain Consumer Power Association, agreed to organize the Intermountain Power Agency ("IPA"), a political subdivision of the State of Utah created pursuant to the provisions of the Interlocal Cooperation Act of the State of Utah, for the express purpose of undertaking and financing IPP. It is currently contemplated that IPA will issue long-term bonds (estimated to aggregate $8 billion) to finance the construction of IPP, with said bonds secured by "take-or-pay" power sales contracts between IPA and purchasers of power from IPP obligating those purchasers to pay whether or not power is produced. On August 6, 1980, the City entered into such a power sales contract obligating it to purchase a 10.23% share of IPP capacity and energy. Payments by the City of its share of IPP power costs (including debt service) are expected to commence in the fiscal year ending 1987. Based upon preliminary estimates, the Consulting Engineer expects that participation in IPP will result in lower costs of power to the City than purchasing the equivalent amount of power from Edison. Pursuant to the IOA, Edison has agreed to integrate IPP as a resource and to provide transmission services to the City's point of delivery.

An environmental impact statement has been prepared by the United States Bureau of Land Management. On December 19, 1979, the Secretary of the Interior announced his approval of the project following the completion of the environmental impact statement. IPA is entering into contracts to acquire approximately 39,500 acre feet of surface water annually from the Sevier River and 5,500 acre feet of ground water annually from wells located in the vicinity of the proposed plant site. IPA has commenced negotiations to acquire a coal supply but no contracts have been executed to obtain coal for the project.

White Pine Project

The City, together with other public and private utilities in California and Nevada, has begun preliminary studies to explore the feasibility of constructing a coal-fired generating station near Ely, Nevada. This generating station would provide approximately 1,500 megawatts of electrical capacity. It is contemplated that White Pine County would finance and construct this project. The bonds issued by White Pine County would be secured by power sales contracts executed with the various purchasers of power from the project. The City's entitlement percentage share for feasibility studies is currently expected to be approximately 3.6%. It is currently anticipated that the electric utilities referred to above will enter into a power supply development agreement with White Pine County in the fall of 1980 for the purpose of conducting further feasibility and environmental studies and obtaining permits and licenses for constructing and operating the project. It is anticipated that White Pine County will issue notes not exceeding $30,000,000 for such purposes. Such notes will be payable from the proceeds of long term bonds issued by the County or from payments by the participants under such agreements on the basis of entitlement shares. The estimated commercial operation dates for each of three 500 megawatt generating units are: 1989, 1990 and 1991, respectively.

California Coal Project

The City has entered into a letter agreement with Edison and other utilities to endeavor to obtain necessary regulatory approvals required to construct and operate the California Coal Project. The project is a proposed 1,500-megawatt plant consisting of three 500-megawatt generating units planned to be located in the eastern desert in Southern California. A Notice of Intent for certification and approval of a plant site was filed with the California Energy Commission on December 28, 1979. Proceedings are currently being held before that Commission with respect to the Notice of Intent. A decision by the California Energy Commission is expected by January 15, 1981. The City's entitlement percentage share for the feasibility studies currently is 3.38%. The project is planned to be in operation in the early 1990's with Edison acting as the project manager.

North Brawley Geothermal Project

Union Oil Company ("Union") has entered into an agreement with Edison wherein Union agreed to construct a 10 megawatt demonstration plant and a separate agreement wherein Union agreed to sell geothermal energy to Edison to operate the 10 megawatt demonstration plant. It has been proposed that the City, along with other public agencies in Southern California, agree to acquire a 50% ownership interest in the demonstration plant for the purpose of studying the technological developments and operating experience obtained in the operation of the demonstration plant, all for the purpose of constructing additional geothermal units.

The City is studying whether or not to enter into an agreement with LADWP, Burbank, Glendale, Pasadena, Riverside and the Imperial Irrigation District to acquire ownership rights in the demonstration plant and the right to acquire options to purchase geothermal energy from Union in the North Brawley Geothermal Field for approximately 450 megawatts of geothermal energy. The City's proposed entitlement percentage share would be approximately 7%.

Other Possible Resources

The City is also studying the feasibility of participating in the acquisition of some hydroelectric resources in the State of California. Along with the City of Riverside, the City has filed an application for a preliminary permit to study a proposed 140 megawatt hydroelectric project at Balsam Meadows, FERC Project No. 2858. The City has also filed, along with the cities of Azusa, Banning, Colton and Riverside and the Northern California Power Agency, a competing application with Pacific Gas and Electric Company for a license to operate the existing hydroelectric facilities at Cresta and Rock Creek powerhouses on the Feather River, FERC Project No. 1962.

It is unknown whether either of these applications will be granted by FERC.

Southern California Public Power Authority

The City and other public agencies in Southern California are members of a joint powers authority. As currently contemplated, such authority would provide for the financing and construction of electric generating and transmission projects for participation by some or all of its members. To the extent the City participates in any project developed by the authority, it is anticipated that the City would be obligated for its share of cost on a "take-or-pay" basis whether or not power is generated or delivered.

LITIGATION

Relating to the City and the 1980 Bonds

There is no litigation pending or, to the knowledge of the City, threatened, questioning the corporate existence of the City, or the title of the officers of the City to their respective offices, or the validity of the 1980 Bonds or the power and authority of the City to issue the 1980 Bonds, or the validity of the IOA, Participation Agreement, Supplemental Agreement, and Transmission Service Agreement, except as noted below. There is no litigation pending, or to the knowledge of the City, threatened, questioning the authority of the City to fix, charge and collect rates for the sale of power and energy by the City as provided in the Resolution.

Other Litigation

City of Anaheim, Et Al. v. So. California Edison Company

On March 2, 1978 the Cities of Anaheim, Riverside, Banning, Colton and Azusa filed an action in the Federal District Court for the Central District of California alleging that Edison was involved in a conspiracy to restrain and monopolize trade and price discrimination all in violation of the Sherman Antitrust Act and the Robinson-Patman Price Discrimination Act. On or about May 5, 1978 Edison filed motions for a more definite statement, to dismiss the complaint for failure to state a claim, or in the alternative, to stay the action. The District Court denied Edison's Motion to Dismiss, but stayed the case pending FERC's decision in Docket No. ER 76-205, E-7796 and E-7777. The District Court lifted the stay on September 10, 1979 to permit discovery on certain matters. On February 10, 1980 the District Court vacated the stay entirely. On November 29, 1979 Edison filed its Answer and Counterclaim requesting damages in an unspecified amount. A status conference is scheduled for February 1981. Counsel to the City believes, based upon the allegations contained in the Counterclaim, which allegations constitute the factual basis for such belief that the counterclaim of Edison is without merit.

The City is a party plaintiff or intervenor in various rate cases and other proceedings affecting the Electric System. The City does not believe that any of these proceedings will have an adverse effect upon the financial condition of the Electric System.

AVAILABLE INFORMATION REGARDING EDISON AND SAN DIEGO

Information at various dates concerning, among other things, the respective financial positions of Edison and San Diego and their respective abilities to pay their proportionate shares of capital and other costs of the Project and otherwise to perform their obligations under the various Project agreements is contained in reports and other information filed by each of such companies pursuant to the informational requirements of the Securities Exchange Act of 1934. Such reports and other information on file can be inspected and copied at the office of the Securities and Exchange Commission at Room 6101, 1100 L Street, N.W., Washington, D.C.; Room 1228, Everett McKinley Dirksen Building, 219 South Dearborn Street, Chicago, Illinois; Room 1100, Federal Building, 26 Federal Plaza, New York, New York; and Suite 1710, Tishman Building, 10960 Wilshire Boulevard, Los Angeles, California. Copies of such materials can also be obtained at prescribed rates from the Commission at its principal office at 500 North Capitol Street, N.W., Washington, D.C. 20549. Certain securities of each of such companies are listed on the New York, American and Pacific Stock Exchanges and information on file can be inspected at the respective offices of these Exchanges at Room 401, 20 Broad Street, New York, New York; 86 Trinity Place, New York, New York; and 301 Pine Street, San Francisco, California.

LEGALITY FOR INVESTMENT BY SAVINGS AND COMMERCIAL BANKS IN CALIFORNIA

The Superintendent of Banks of the State of California has certified that the 1980 Bonds will, when issued, constitute legal investments for savings and commercial banks in California.

CERTAIN LEGAL MATTERS

Legal matters incident to the authorization, issuance and sale of the 1980 Bonds are subject to the unqualified approving opinion of O'Melveny & Myers, Los Angeles, California, Bond Counsel. Said opinion in substantially the form attached as Appendix I will be printed on the Bonds. Certain legal matters will be passed upon for the City by Alan R. Watts, Esq., Special Counsel, and for the Underwriters by their counsel, Messrs. Mudge Rose Guthrie & Alexander.

UNDERWRITING

The Underwriters have jointly and severally agreed to purchase all, but not less than all, of the 1980 Bonds at a price representing an aggregate discount of 1.712% from the initial public offering prices set forth on the cover page hereof.

The Underwriters may offer and sell the 1980 Bonds to certain dealers and others at prices lower than the initial public offering prices and the initial public offering prices may be changed from time to time by the Underwriters.

TAX EXEMPTION

In the opinion of Bond Counsel, interest on the 1980 Bonds is exempt from income taxes of the United States of America under present federal income tax laws, and is also exempt from personal income taxes of the State of California under present state income tax laws.

Bond Counsel is further of the opinion that the amount of original issue discount, if any, in the selling price of the 1980 Bonds (which original issue discount with respect to each maturity of the 1980 Bonds equals, at a minimum, the lesser of (i) the difference between the principal amount of such 1980 Bonds and the price paid to the underwriters by the original purchasers of a substantial portion of the 1980 Bonds of such maturity, and (ii) the difference between the principal amount of such 1980 Bonds and the price paid by the Underwriters, calculated in each case without regard to accrued interest) represents interest which is exempt from federal income taxation to the same extent expressed in the preceding paragraph; provided, however, that in the case of a sale or exchange of such 1980 Bonds or the redemption of such 1980 Bonds prior to maturity such original issue discount is apportioned among such original purchaser of such 1980 Bonds and subsequent holders, and each respective holder is entitled to treat as exempt from federal income taxation, at a minimum, that portion of his gain, if any, which does not exceed the amount of such original issue discount with respect to such 1980 Bonds multiplied by a fraction the numerator of which is the number of days (computed on an actual calendar day basis) such 1980 Bonds were owned by him and the denominator of which is the total number of days from the date of issuance of such 1980 Bonds to the date of maturity of such 1980 Bonds.

This Official Statement has been approved by the City Council of the City of Anaheim

CITY OF ANAHEIM, CALIFORNIA

/s/ John Seymour
Mayor

/s/ W.O. Talley
City Manager

/s/ Gordon W. Hoyt
Public Utilities General Manager

October 10, 1980

R. W. BECK AND ASSOCIATES

ENGINEERS AND CONSULTANTS

PLANNING
DESIGN
RATES
ENVIRONMENTAL
ECONOMICS
MANAGEMENT

TOWER BUILDING
7TH AVENUE AT OLIVE WAY
SEATTLE, WASHINGTON 98101
206 622 5000

GENERAL OFFICE
SEATTLE, WASHINGTON

APPENDIX A

October 10, 1980

City of Anaheim
Civic Center
200 South Anaheim Blvd.
Anaheim, California 92805

Gentlemen:

Subject: Consulting Engineer's Report
Anaheim Electric System

Presented herewith is a summary of our analyses, investigations and studies with respect to the proposal by the City of Anaheim, California (the "City") to issue $84,000,000 of Electric Revenue Bonds, Issue of 1980 (the "1980 Bonds") for the purpose of paying a portion of the cost of acquiring an ownership interest in the San Onofre Nuclear Generating Station, Units 2 and 3 and certain common facilities (together referred to herein as the "Project"). The Project is being constructed by the Southern California Edison Company ("Edison") and San Diego Gas and Electric Company. Edison has been designated as Project manager and operator. The City proposes to purchase its ownership share from Edison. Based on estimated costs of the Project, the City expects that the Bonds will be sufficient to acquire a 1.66% ownership interest in the Project. However, the City's present financing program provides that additional bonds could be issued at later dates if necessary to pay any remaining cost of acquiring its ownership interest in the Project.

The City entered into a Settlement Agreement dated August 4, 1972 with Edison which provided, among other things, that the City may acquire a 1.66% ownership interest in the Project and that Edison will provide the necessary transmission services to the City to deliver the output of the Project to the City's system. The City has signed an Integrated Operations Agreement ("IOA") and will sign upon delivery of the 1980 Bonds a Supplemental Agreement for the Integration of Anaheim's Entitlement in San Onofre Units 2 and 3 ("Supplemental Agreement") with Edison which provide, among other things, for the operation of the Project by Edison for the benefit of the City. Under the IOA, Edison will continue to supply the City's power and energy requirements over and above the capability of the City's share of the Project and any future City owned resource and credit the City on its monthly billing statements for the power and energy generated by such resources that are integrated with Edison's resources. The Supplemental Agreement provides that the Project will be included as an integrated resource pursuant to the IOA. Further, Edison has signed and, upon delivery of the 1980 Bonds, the City will sign the San Onofre Units 2 and 3 Participation Agreement which sets forth the terms and conditions under which the City will participate in the ownership and output of the Project, and the Transmission Service Agreement in which Edison agrees to provide Transmission of the City's share of the output of the Project to the City's point of delivery. For a summary of the San Onofre Units 2 and 3 Participation Agreement, the Transmission Service Agreement, the IOA and the Supplemental Agreement, see Appendices B, C, D, and E respectively to the Official Statement to which this report is attached ("Official Statement").

Currently all of the City's power and energy is purchased at wholesale rates from Edison except for interruptible energy which is purchased from other public and private electric utilities and governmental agencies when it is available at an economically attractive price. The City expects to use its share of the output of the Project to replace a portion of the power and energy currently being purchased from Edison, with resulting long-term economic benefits to the City.

THE PROJECT

San Onofre Nuclear Generating Station

The San Onofre Nuclear Generating Station consists of two 1,100 MWe nuclear generating units currently under construction and an existing nuclear generating unit No. 1 (not part of the Project) rated at 450 MWe. The station is located on an 84-acre site approximately three miles south of San Clemente, California and within the U.S. Marine Corps Base at Camp Pendleton. Except for certain common facilities shared with the existing unit, the Project consists of the two units under construction. These units, Units 2 and 3, are essentially identical in design and will share certain common facilities including the control room and certain other facilities.

The nuclear steam supply systems for the Project, supplied by Combustion Engineering, Inc., are closed-cycle pressurized water reactor systems rated at 3,410 MWt each with two reactor coolant loops. The turbine generators are tandem compound units supplied by GEC Turbine Generators, Ltd. (formerly English Electric). The main condensers are being supplied by Ingersoll Rand and will be cooled by circulating seawater obtained through large intake lines extending out 5,200 feet into the ocean.

The main generators are rated at 1,312,950 kVA. The main transformers will step up the output voltage of each generator to 220 kV for interconnection into the facilities of Edison's transmission network.

The Project is being designed and the construction is being managed by the Bechtel Power Company for Edison. Edison is managing the startup program and will operate the two units upon receiving a commercial operating license.

It is currently planned that the Project will be owned as tenants-in-common by the following utilities.

	Ownership Interest
Edison	76.55%
San Diego Gas & Electric Company	20.00
City of Riverside	1.79
City of Anaheim	1.66
Total	100.00%

Status and Schedule

Construction of Unit 2 began in March 1974 after receipt of a construction permit from the Nuclear Regulatory Commission ("NRC") in October 1973, and the major construction of Unit 3 started in June 1975. Fuel loading for Unit 2 is scheduled for the second quarter of 1981 with commercial operation in December 1981. Fuel loading for Unit 3 is scheduled for the third quarter of 1982 with commercial operation scheduled for February 1983. An operating license must be issued for each unit before fuel loading may begin for that unit. As of June 27, 1980, construction of Unit 2 was approximately 93% complete and Unit 3 was approximately 63% complete. Edison's current schedule anticipates that the operating license will be received from the NRC in sufficient time to meet the projected fuel loading and startup schedules. For a discussion of the status of the operating license, see the caption "Regulatory Matters — Nuclear Regulatory Commission" in the Official Statement.

Construction work on the Project is currently halted due to a strike as part of a western regional work stoppage by the International Brotherhood of Boilermakers. The City is unable to predict the duration of the stoppage, or its impact on the construction schedule or cost of the Project. For a further discussion, see the caption "The Project — Status and Schedule of Construction" in the Official Statement.

Estimated Financing Requirements for the Project

The following table shows the estimated cost of constructing and financing the Project:

	Total Project(1)	City's Share
Land and Land Rights	$ 3,270,000	$ 54,000
Structures and Improvements	680,928,000	11,304,000
Reactor Plant Equipment	811,009,000	13,463,000
Turbogenerator	460,008,000	7,636,000
Accessory Electrical Equipment	195,485,000	3,245,000
Miscellaneous Power Plant Equipment	58,500,000	971,000
Subtotal Direct Construction Costs	$2,209,200,000	$36,673,000
Ad Valorem Taxes (2)		648,000
Nuclear Fuel (1)		4,798,000
City's Contingency (3)		3,356,000
Total Construction Costs		$45,475,000
Interest Payable to Edison(4)		8,947,000
Reserve Fund(5)		8,000,000
Interest Funded During Construction(6)		16,800,000
Financing Costs(7)		8,950,000
Gross Requirements		$88,172,000
Less: Interest Income (8)		4,172,000
Net Financing Requirements		$84,000,000

(1) Estimated by Edison.

(2) Estimated share of tax to be paid by City.

(3) Additional contingency not included in Edison's estimated costs to allow funds for uncertainties in the licensing schedule and possible additional design changes.

(4) City's share of estimated interest costs paid by Edison through October 1977 and City's interest costs at [illegible]% per year on funds expended by Edison from November 1, 1977 to October 31, 1980.

(5) Approximate maximum annual debt service.

(6) Based on 8.0% annual interest rate on the 1980 Bonds. 100% of the interest on the 1980 Bonds is capitalized until October 1, 1982 and 50% of the interest on the 1980 Bonds is capitalized until December 1, 1983.

(7) Includes maximum allowable Bond discount of $8,400,000 and $550,000 for costs of issuance.

(8) From temporary investment at an assumed interest rate of 7% of the 1980 Bond proceeds deposited in the Construction Account and in the Interest During Construction account. Also included are 100% of investment income on the Reserve Fund, invested at an assumed interest rate of approximately 9.0%, until October 1982 and 50% of such interest income until December 1983. The interest earnings on the Reserve Fund are presumed to reach the Electric System Surplus Revenue Fund and as such, subject to the pledge of the 1976 Subordinated Bonds, are required by the Resolution authorizing the 1980 Bonds to be deposited in the Construction Account to the extent not otherwise needed in accordance with such Resolution.

Effects of the Three Mile Island Accident

Following the accident at the Three Mile Island Unit No. 2, ("TMI-2"), the NRC has undergone a reorganization and an interruption of its licensing efforts. The licensing requirements for nuclear plants are continually being re-evaluated in light of the TMI-2 accident which has resulted in some uncertainty in the licensing schedules for all plants near the completion of construction.

The TMI-2 accident analysis of the NRC has resulted in additional design change requir nents by the NRC. Edison has estimated that these design changes will result in an additional $30,000,000 plus overhead costs to the Project and have included such costs in their estimate of the total direct construction costs. Additional design changes may be required in the future.

Nuclear Fuel

The nuclear fuel cycle consists of four basic elements prior to insertion of the fuel assemblies in a nuclear reactor. These elements include acquisition of uranium concentrates, conversion of the uranium concentrates to uranium hexafluoride, enrichment of the uranium hexafluoride and fabrication of the enriched uranium into fuel assemblies. After the fuel has been used in the reactor, it is removed for reprocessing or disposal.

The following table shows the amount of coverage of the necessary materials and coverage Edison has acquired for the Project:

	Unit No. 2		Unit No. 3	
	Full Coverage Through	% Coverage Through 1990	Full Coverage Through	% Coverage Through 1990
Uranium	1985	85	1985	52
Conversion	1990	100	1990	100
Enrichment	2009	100	2009	100
Fabrication	1984	25	1985	55
Storage	1991	100	1992	100

At the present time, no operating facilities for the reprocessing of spent fuel are available, and in April 1977 the President of the United States announced an indefinite deferral of reprocessing spent fuel and the use of plutonium. In October 1977, the United States Department of Energy ("DOE") announced its intent to accept and take title to spent fuel from utilities upon payment of a one-time storage fee. The details of this DOE program are currently being formulated. Edison is providing on-site spent fuel storage capacity for the Project estimated to be sufficient to accommodate storage of the discharges of all spent fuel from Unit No. 2 through 1991 and from Unit No. 3 through 1992. By then it is assumed that an appropriate program will have been implemented to accept spent fuel for placement in a suitable repository.

Estimated Cost To The City of Power from the Project

The following table shows the estimated annual costs of power from the Project as it is delivered to the City's system for the years ending June 30, 1982 through 1990 based on Edison's estimate of energy generation by the Project.

ESTIMATED ANNUAL COST TO THE CITY OF POWER

FROM THE PROJECT

(000)

	Fiscal Year Ending June 30								
	1982	1983	1984	1985	1986	1987	1988	1989	1990
Interest and Amortization(1)	$ —	$2,520	$ 6,258	$ 7,989	$ 7,969	$ 7,986	$ 7,973	$ 7,977	$ 7,982
Land Easement(2)	1	2	3	3	4	4	4	4	4
Operation and Maintenance(2)	245	500	925	1,337	1,471	1,612	1,767	1,937	2,123
Administrative and General(2)	143	299	375	416	452	492	535	582	634
Nuclear Insurance(2)	48	115	157	174	190	206	224	244	266
Nuclear Fuel(3)	103	837	1,763	2,052	1,890	2,347	2,889	2,493	2,588
Renewals and Replacements(4)	107	270	412	445	481	519	561	606	654
Taxes(5)	5	56	107	112	112	112	112	112	112
Transmission(6)	40	100	143	145	147	149	152	154	156
Subtotal	$ 692	$4,699	$10,143	$12,673	$12,716	$13,427	$14,217	$14,109	$14,519
Less: Interest Earnings(7)	—	275	579	727	727	727	727	727	727
Total	$ 692	$4,424	$ 9,564	$11,946	$11,989	$12,700	$13,490	$13,382	$13,792
Energy Delivered (Millions of kWh)(8)	32	102	167	199	212	222	222	222	222
Cost (Mills per kWh)	21.6	43.4	57.3	60.0	56.6	57.2	60.8	60.3	62.1

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(1) Based on 100% of interest capitalized until October 1, 1982 and 50% of the interest capitalized until December 1, 1983. Remaining interest to be paid from revenues.

(2) Estimated by Edison.

(3) Based on Edison nuclear fuel costs.

(4) Estimated at 1.0% of capital costs and escalated at 8.0% per year.

(5) Based on the City's share of ad valorem taxes at the time of acquiring its ownership share.

(6) Based on the Transmission Service Agreement.

(7) Earnings on the Reserve Fund not deposited in the Construction Account at an assumed interest rate of approximately 9%.

(8) Computed as the City's share of estimated total generation at the Project site, less energy transmission losses estimated at approximately 1%.

ENERGY AND CAPACITY REQUIREMENTS

During the last five fiscal years, the City's electric customers have increased by 15.2%, from 71,684 customers in 1976 to 82,571 customers in 1980.

During the same period of time, the City's electric energy requirements have increased from 1,583,260,000 kilowatt-hours in 1976 to 1,834,789,000 kilowatt-hours in 1980, a 15.9% total increase and a 3.8% increase per year. Peak demand increased from 330,400 kilowatts in 1976 to 396,000 kilowatts in 1980 and 408,000 kilowatts in July 1980

Historical Number of Customers and Load Requirements

Fiscal Year Ending June 30	Average Number of Customers	% Increase (1)	Energy Requirements (MWh)	% Increase (1)	Peak Demand (MW)	% Increase (1)
1976	71,684	—	1,583,260	—	330.4	—
1977	75,539	5.4	1,661,338	4.9	328.0	(0.7)
1978	77,439	2.5	1,722,736	3.7	347.6	6.0
1979	80,038	3.4	1,834,202	6.5	395.6	13.8
1980	82,571	3.2	1,834,789	0.0	396.0	0.1

(1) Over previous year.

The City's load growth between 1979 and 1980 was lower than that experienced in prior years with only a slight increase in energy requirements. The City feels the slower growth rate can primarily be attributed to milder than average temperatures during the year and to the City's ongoing conservation efforts. The City's forecast load requirements, shown on the following table, are based on a forecast the City has submitted to the California Energy Commission. The forecast shows a higher rate of growth than that experienced in the 1979-1980 period but less than that experienced over the previous five-year period. The load forecast, as developed by the City, was prepared considering, among other things, economics of the region, price elasticity and the City's ongoing conservation programs.

Forecast Peak and Energy Requirements(1)

Fiscal Year Ending June 30	Peak Demand (MW)	% Increase (2)	Energy Requirements (MWh)	% Increase (2)
1981	415	—	1,905,000	—
1982	428	3.1	1,999,000	4.9
1983	450	5.1	2,107,000	5.4
1984	473	5.1	2,215,000	5.1
1985	496	4.9	2,313,000	4.4
1986	515	3.8	2,399,000	3.7
1987	532	3.3	2,478,000	3.3
1988	547	2.8	2,551,000	2.9
1989	562	2.7	2,622,000	2.8
1990	576	2.5	2,688,000	2.5

(1) Estimated by the City.

(2) Over previous year.

POWER SUPPLY PLANNING

Currently, all of the City's electricity is purchased at wholesale rates from Edison except for interruptible energy which is purchased from other public and private electric utilities and governmental agencies when it is available at an economically attractive price. For a discussion of the contractual arrangements between the City and Edison and the City and the Nevada Power Company which has provided certain economy energy to the City (See the subcaption, "Power Supply" under the caption "City of Anaheim — The Electric System" in the Official Statement). The capacity and energy expected to be received from the Project will be used to displace a portion of the power currently purchased from Edison.

Future Power Supply Resources

The City has an ongoing program to investigate potential power supply resources, in addition to the Project, which could be used to offset purchases of power from Edison as well as to meet all or some portion of forecast load growth. The City has contracted to purchase power from the Intermountain Power Project ("IPP") and is involved in the feasibility studies of other projects. The City plans on evaluating each of these potential future resources on the basis of providing an economically reliable supply of electric power to its customers. The status of IPP and other projects under consideration are described herein.

Intermountain Power Project

In 1974 the City entered into a membership and study agreement with the California cities of Riverside, Burbank, Glendale, Pasadena and the Department of Water and Power of The City of Los Angeles ("LADWP") and with the Intermountain Consumer Power Association, composed of a group of Utah municipalities and rural electric cooperatives. The purpose of the membership and study agreement was to investigate the feasibility of constructing and operating IPP. The proposed IPP is a 3,000-megawatt coal-fired electric-generating plant consisting of four 750-megawatt generators, to be located in Millard County in central Utah. The presently projected commercial operation date of the first unit is July 1986 with other units following at one-year intervals. The IPP plan includes construction of two 500± kV direct-current transmission lines from the plant site to the Leon Substation in the vicinity of Victorville, California where the lines will be connected to the LADWP transmission grid. The City will receive its power over this transmission line. A feasibility study has been completed by LADWP pursuant to an agreement between IPP and LADWP. As currently contemplated, LADWP will act as project manager.

In May 1977, several Utah municipalities, which are members of the Intermountain Consumer Power Association, organized the Intermountain Power Agency ("IPA"), a political subdivision of the State of Utah, for the express purpose of financing and constructing IPP. It is proposed that IPA issue long term bonds (estimated to aggregate approximately $8 billion) to finance construction of IPP with said bonds secured by "take or pay" power sales contracts between IPA and purchasers of power from IPP obligating the purchasers to pay whether or not power is produced. The City has entered into such a contract to purchase a 10.23% share of IPP capacity and energy. Payments by the City of its share of IPP costs (including debt service) are expected to commence in 1987. Based on preliminary estimates, it is expected that participation in IPP will result in lower costs of power to the City than purchasing the equivalent amount of power from Edison. Pursuant to the IOA, Edison has agreed to integrate IPP as a resource and to provide transmission services to the City's point of delivery.

An environmental impact statement has been prepared by the United States Bureau of Land Management. On December 19, 1979, the Secretary of the Interior announced his approval of the project following the completion of the environmental impact statement. IPA is entering into contracts to acquire approximately 39,500 acre feet of surface water annually from the Sevier River and 5,500 acre feet of ground water annually from wells located in the vicinity of the proposed plant site. IPA has commenced negotiations to acquire a coal supply but no contracts have been executed to obtain coal for the project.

White Pine Project

The City, together with other public and private utilities in California and Nevada, has begun preliminary studies to explore the feasibility of constructing a coal-fired generating station near Ely, Nevada. This generating station would provide approximately 1,500 megawatts of electrical capacity. It is contemplated that White Pine County would finance and construct this project. The bonds issued by White Pine County would be secured by power sales contracts executed with the various purchasers of power from the project. The City's percentage share for feasibility studies is currently expected to be approximately 3.6%. It is currently anticipated that the electric utilities referred to above will enter into a power supply development agreement with White Pine County in the fall of 1980 for the purpose of conducting a study to determine the feasibility of constructing and operating the project. The estimated commercial operation dates for each of three 500 megawatt generating units are: 1989, 1990 and 1991, respectively. It is anticipated that White Pine County will issue notes not exceeding $30,000,000 for conducting a feasibility study and licensing of the Project.

California Coal Project

The City has entered into a letter agreement with Edison and other utilities to endeavor to obtain necessary regulatory approvals required to construct and operate the California Coal Project. The project is a proposed 1,500-megawatt plant consisting of three 500-megawatt generating units planned to be located in the eastern desert in Southern California. A Notice of Intent for certification and approval of a plant site was filed with the California Energy Commission on December 28, 1979. Proceedings are currently being held before that Commission with respect to the Notice of Intent. A decision by the California Energy Commission is expected by January 15, 1981. The City's entitlement percentage share for the feasibility studies currently is 3.38%. The project is planned to be in operation in the early 1990's with Edison acting as the project manager.

North Brawley Geothermal Project

Union Oil Company ("Union") has entered into an agreement with Edison wherein Union agreed to construct a 10 megawatt demonstration plant and a separate agreement wherein Union agreed to sell geothermal energy to Edison to operate the 10 megawatt demonstration plant. It has been proposed that the City, along with other public agencies in Southern California, agree to acquire a 50% ownership interest in the demonstration plant for the purpose of studying the technological developments and operating experience obtained in the operation of the demonstration plant, all for the purpose of constructing additional geothermal units.

The City is studying whether or not to enter into an agreement with LADWP, Burbank, Glendale, Pasadena, Riverside and the Imperial Irrigation District to acquire ownership rights in the demonstration plant and the right to acquire options to purchase geothermal energy from Union in the North Brawley Geothermal Field for approximately 450 megawatts of geothermal energy. The City's proposed entitlement percentage share would be 7%.

Other Possible Resources

The City is also studying the feasibility of participating in the acquisition of some hydroelectric resources in the State of California. Along with the City of Riverside, the City has filed an application for a preliminary permit to study a proposed 140 megawatt hydroelectric project at Balsam Meadows, Federal Energy Regulatory Commission, ("FERC") Project No. 2858. The City has also filed, along with the cities of Azusa, Banning, Colton and Riverside and the Northern California Power Agency, a competing application with Pacific Gas and Electric Company for a license to operate the existing hydroelectric facilities at Cresta and Rock Creek powerhouses on the Feather River, FERC Project No. 1962.

It is unknown whether either of these applications will be granted by FERC.

Southern California Public Power Authority

The City and other public agencies in Southern California are members of a joint powers authority. As currently contemplated, such authority would provide for the financing and construction of electric generating and transmission projects for participation by some or all of its members. To the extent the City participates in any project developed by the authority, it is anticipated that the City would be obligated for its share of costs on a "take or pay" basis whether or not power is generated or delivered.

PROJECTED RESOURCES AND POWER COSTS

City's Power Supply

Pending further development of IPP or other generating resources the City may acquire, we have assumed herein that the City's power requirements above that produced by the Project will be met by purchases from Edison through the IOA. The following table shows the annual peak and energy requirements as estimated by the City and the estimated amounts of peak and energy expected to be supplied from the Project and from Edison purchases.

	Peak (MW)			Energy (Millions of kWh)		
Fiscal Year Ending June 30	Requirements	Purchased from Edison	Capacity from the Project	Requirements	Purchased from Edison	Generated by the Project
1981	415.0	415.0	—	1,905	1,905	—
1982	428.0	428.0	—(1)	1,999	1,967	32
1983	450.0	435.5	14.5(1)	2,107	2,005	102
1984	473.0	444.1	28.9	2,215	2,048	167
1985	496.0	467.1	28.9	2,313	2,114	199
1986	515.0	486.1	28.9	2,399	2,187	212
1987	532.0	503.1	28.9	2,478	2,256	222
1988	547.0	518.1	28.9	2,551	2,329	222
1989	562.0	533.1	28.9	2,622	2,400	222
1990	576.0	547.1	28.9	2,688	2,466	222

(1) The City will receive certain capacity credits for the Project for the years ending June 30, 1982 and 1983 from Edison; however, not all capacity from the City's share of the Project will be available to meet the City's forecast peak load for those years.

Under the provisions of the IOA, the City will receive credit for the amount of capacity of its integrated resources less transmission losses and less the City's share of Edison system reserves. For purposes of our analyses, we have assumed the transmission losses would be approximately 1% and that Edison system capacity reserves would be 20% for each year of the study.

Cost of Power to the City

We have projected the costs of power to the City for the period 1982 through 1990 on the basis that the City would purchase from Edison all power requirements not supplied from the Project. In accordance with the IOA, the City will purchase power from Edison at Edison's partial requirements rates. In addition, when a City Capacity Resource, such as the Project, is not available, the City shall purchase Contract Energy, which is the amount of energy capability associated with the capacity credit, less energy received from City Integrated Resources.

During the study period Contract Energy is estimated to average less than 5% of all energy purchased from Edison by the City. The Contract Energy cost is determined by multiplying Edison's cost of fuel for conventional oil-fired combustion turbine and combined-cycle generating resources measured in dollars per Btu by the weighted heat rate of these generating resources measured in Btu's per kilowatt-hour. This rate plus a charge for certain other costs associated with fuel is then adjusted for transmission losses to the City's point of delivery.

Should extended outages occur at the City Integrated Resource, the City will be required to provide or purchase from Edison Replacement Capacity, in accordance with the IOA. The amount of Replacement Capacity that the City must purchase is the greater of (i) the maximum kilowatt difference (rated generating capability of the City's Integrated Resource for a given day less the capacity available from the resource that day) which has existed for 70 or more consecutive days immediately preceding that day, or (ii) the maximum kilowatt difference which exists for that day and has existed for 100 or more non-consecutive days during the 180 consecutive-day period immediately preceding that day. The City will not be required to purchase Replacement Capacity until a generating unit has been out or partially out of operation for more than 70 consecutive days or more than 100 days out of 180 consecutive days and the City has exhausted its maintenance reserve for each unit for that year. The maintenance reserve is an amount of megawatt-days established for each City's Integrated Resource each year from which the City may withdraw megawatt-days to be credited against City's Replacement Capacity obligation for each unit.

The cost of Replacement Capacity, measured in dollars per kilowatt-day, is based on the costs of electric generating facilities installed during the five years just prior to the current year. However, the City expects to be required to pay the cost of Replacement Capacity only under unusual circumstances arising from extended outages of its Integrated Resources. Therefore, we have not considered the effects of Replacement Capacity costs on the City's power supply costs.

Based upon the foregoing assumptions, forecast wholesale power rates from Edison and forecast Project costs, the following table shows the estimated power supply costs for the City for the period from 1982 through 1990, with and without Project ownership. The savings to the City resulting from Project ownership as shown on that table increase from $794,000 in the fiscal year ending June 30, 1982 to $9,510,000 in the fiscal year ending June 30, 1990. However, these projected savings will differ from actual savings to the extent that actual conditions differ from those assumed.

ESTIMATED POWER SUPPLY COSTS AND SAVINGS TO THE CITY
Fiscal Year Ending June 30
(000)

	1982	1983	1984	1985	1986	1987	1988	1989	1990
ANNUAL POWER COSTS WITH THE PROJECT									
San Onofre Project Costs	$ 692	$ 4,424	$ 9,564	$ 11,946	$ 11,989	$ 12,700	$ 13,490	$ 13,382	$ 13,792
Purchased Power Costs (1)	114,502	139,153	169,473	195,265	217,086	240,026	265,880	287,111	307,793
Total Annual Power Costs	$115,194	$143,577	$179,037	$207,211	$229,075	$252,726	$279,370	$300,493	$321,585
Total Energy Requirements (GWh)	1,999	2,107	2,215	2,313	2,399	2,478	2,551	2,622	2,688
Unit Power Costs (Mills/kWh)	57.6	68.1	80.8	89.6	95.5	102.0	109.5	114.6	119.6
ANNUAL POWER COSTS WITHOUT THE PROJECT									
Purchased Power Costs	$115,988	$144,884	$180,862	$210,839	$235,139	$260,338	$287,538	$309,638	$331,095
Unit Power Costs (Mills/kWh)	58.0	68.8	81.7	91.2	98.0	105.1	112.7	118.1	123.2
Savings to the City (2)	$ 794	$ 1,307	$ 1,825	$ 3,628	$ 6,064	$ 7,612	$ 8,168	$ 9,145	$ 9,510

(1) Based on projected Edison energy and capacity rates and projected Edison contract energy costs.

(2) Estimated savings to City are calculated from estimates of Project costs and Edison wholesale power rates which are based on the assumptions set out in this report. The savings to the City resulting from Project ownership shown above will differ from actual savings to the extent that actual conditions differ from those assumed.

PROJECTED OPERATING RESULTS

Based on the foregoing forecast of power costs and on certain data supplied by the City, we have prepared a projection of operating results of the City's electric system for the fiscal periods ending 1981 through 1985. In these projections, we show increases in revenue requirements beyond those generated by the City's existing rates. Required revenues are based on covering projected operating expenses, debt service on the 1980 Bonds and previous bonds issued by the City, and on meeting the City's projected capital improvement program and other non-operating financial commitments. The additional revenues required are primarily to meet future capital improvements and escalating purchased power costs from Edison.

PROJECTED OPERATING RESULTS

(000)

	Fiscal Year Ending June 30				
	1981	1982	1983	1984	1985
Gross Revenues:					
Revenues from Sales of Electricity:					
At 1980 Average Charges	$100,280	$105,217	$110,864	$116,545	$121,731
Additional Revenues Required (1)	11,240	32,992	55,454	85,775	110,510
Subtotal	$111,520	$138,209	$166,318	$202,320	$232,241
Miscellaneous Operating Revenues (2)	274	263	275	287	303
Interest Income (3)	723	922	1,116	1,359	1,576
Interest Income (Reserve Fund) (4)	478	727	727	727	727
Total Estimated Gross Revenues	$112,995	$140,121	$168,436	$204,693	$234,847
Operating Expenses:					
Power Production — San Onofre Units 2 and 3	$ 0	$ 692	$ 2,179	$ 3,885	$ 4,684
Purchased Power — Edison	96,632	114,502	139,153	169,473	195,265
Other Operation and Maintenance Expense (2)	9,443	10,294	11,431	12,303	13,205
Total Estimated Operating Expenses Excluding Depreciation and Amortization	$106,075	$125,488	$152,763	$185,661	$213,154
Total Estimated Net Revenues	$ 6,920	$ 14,633	$ 15,673	$ 19,032	$ 21,693
Debt Service on the Bonds:					
Outstanding Bonds	$ 1,064	$ 1,057	$ 1,050	$ 1,047	$ 1,048
Proposed Bonds (5)	0	0	2,520	6,258	7,989
Total Debt Service on the Bonds	$ 1,064	$ 1,057	$ 3,570	$ 7,305	$ 9,037
Balance for Other Purposes (6)	$ 5,856	$ 13,576	$ 12,103	$ 11,727	$ 12,656
Debt Service Coverage on the Bonds (7)	6.50	13.84	4.39	2.61	2.40

(1) Additional revenues required primarily to meet costs of future capital improvements and escalating purchased power costs from Edison.

(2) Estimated by the City.

(3) Estimated by the City. Includes interest earnings on existing Reserve Fund at an assumed 8.5% interest rate and interest earnings on other funds including unrestricted cash and investments at an assumed 7% interest rate.

(4) For the 1980 Bonds only at an assumed reinvestment rate of approximately 9.0%.

(5) Based on 100% of interest capitalized to October 1, 1982; 50% of interest capitalized to December 1, 1983.

(6) Includes, among other things, payments to renewal and replacement account as required by the Bond Resolution and a payment to the general fund, funds for electric system capital improvements and a payment of $2,280,000 in 1981 on subordinated bonds. In addition, the balances shown include interest earnings on the Reserve Fund expected to be available for transfer to the Construction Fund.

Year Ending June 30	1981	1982	1983	1984
Interest Earnings (000)	$478	$727	$452	$148

(7) Ratio of total estimated net revenues for other purposes to total debt service on the bonds.

CONSIDERATIONS AND ASSUMPTIONS

The estimates and projections, contained herein, of the operations of the electric system of the City are based upon, among other things, information made available to us by Edison, as manager of the Project, and from the City. These estimates and projections are also based upon the following principal considerations and assumptions which in light of inflation rates and other conditions presently prevailing in the economy appear to be reasonable:

1. The forecast power and energy requirements were estimated by the City.

2. The capital expenditures and operation and maintenance expenses of the City's electric system will follow historical trends and have been estimated by the City.

3. Commercial operation for Units 2 and 3 of the Project, respectively, will be December 1981 and February 1983 as estimated by Edison.

4. Based on Edison's estimate of Total Direct Construction Costs of the Project, the City's share of such costs will be $36,673,000.

5. Nuclear fuel costs, ad valorem taxes and all other operating costs of the Project were estimated by Edison.

6. Each unit of the Project will have a plant factor of 35% during the first year of operation, 60% in the second and third years of operation, and 70% thereafter as estimated by Edison.

7. Power and energy requirements of the City beyond that provided by the Project will be purchased from Edison in accordance with the principles of the Integrated Operations Agreement. The City's participation in the Intermountain Power Project or other potential resources available during the forecast period have not been included in forecast power costs to the City.

8. The Bonds will be amortized over 24 years at an annual interest rate of 8%. Reinvestment rate for the Reserve Fund is approximately 9.0%. Reinvestment rate in all other funds is 7%. 100% of the interest on the Bonds is capitalized until October 1, 1982 and 50% of the interest on the Bonds is capitalized until December 1, 1983. 100% reinvestment earnings on the Reserve Fund will be deposited in the Construction Fund until October 1, 1982 and 50% of reinvestment earnings on the Reserve Fund will be deposited in the Construction Fund until December 1, 1983.

9. During the study period, the City will finance the estimated costs of the electric system capital improvement program from current revenues.

10. Transmission for Project power will be provided by Edison at a rate of $3.71 per kilowatt escalated at 1.5% per year with losses from the Project to the City at 1.09% per year.

11. Renewals and replacements are assumed to be 1% of direct construction costs escalated at 8.0% per year.

12. Projected wholesale power and energy rates for Edison are based on recent rate filings, electric system plans and forecasts and their generation resource program. Annual escalation factors for coal and nuclear fuel were 8.0% per year. Fuel oil and natural gas were escalated at 25% from 1980 to 1981, 20% per year from 1981 to 1983, 16% from 1983 to 1984, and 10% thereafter, utilizing a base rate for

fuel oil of $28.00 per barrel in 1980. Operation and maintenance expenses were escalated at approximately 10.0% per year. The resulting average wholesale power rate during our study increased at an average annual rate of 9.3%.

CONCLUSIONS

Based upon our studies, investigation and analyses, the assumptions set forth in this letter and the information supplied by the City and Edison with respect to the proposal by the City to acquire an ownership interest in the Project, we are of the opinion that:

1. The acquisition of an ownership interest in the Project by the City and the operation of the Project under the principles of the Integrated Operations Agreement will provide the City with an economical long-range source of power that will result in lower power supply costs than would result from the continued purchase of all its power requirements from Edison.

2. The forecast overall revenue requirements from the sale of electricity by the City are reduced by the City acquiring an ownership share in the Project rather than continuing to purchase all of its power requirements from Edison.

3. The estimated cost of power from the Project compares favorably with forecast purchase power rates from Edison and with available cost projections of other generating resources potentially available to the City in the 1980's.

4. The construction cost estimates provided by Edison for the Project are comparable with the costs expected for similar projects being developed within the same time frame.

Information appearing in the Official Statement which was taken from or based upon data prepared by us, is properly and accurately reflected in the Official Statement.

Respectfully submitted,

/s/ R. W. BECK AND ASSOCIATES

SUMMARY OF THE SAN ONOFRE UNITS 2 AND 3 PARTICIPATION AGREEMENT

The following is a general summary of certain provisions of the Participation Agreement. Such summary does not purport to be complete and accordingly is qualified by reference to the full text of the Participation Agreement, copies of which may be obtained from the City, upon written request.

Purpose

Edison and the Cities of Riverside, Anaheim and Banning entered into a Settlement Agreement, dated August 4, 1972, under which Edison offered to said Cities participation in the ownership and output of Units 2 and 3 at San Onofre. Anaheim and Riverside have indicated their intent to participate in Units 2 and 3. The purpose of the Participation Agreement is to provide for the terms and conditions under which the Parties will participate in the ownership and output of Units 2 and 3.

Parties

The parties to the Participation Agreement are Edison, San Diego, Riverside and Anaheim. Edison and San Diego have signed the Participation Agreement and the City will sign upon delivery of the 1980 Bonds.

Ownership

Upon execution of the Participation Agreement Edison, San Diego, Riverside and Anaheim shall own facilities as tenants-in-common as follows:

	Edison	San Diego	Riverside	Anaheim
Units 2 and 3	76.55%	20.00%	1.79%	1.66%
Common Facilities	77.12	20.00	1.49	1.39
Project Easements				
Unit 1	80.00	20.00	0	0
Units 2 and 3	76.55	20.00	1.79	1.66
Switchyard Area	80.00	20.00	0	0

Construction Agreement

Edison assigns to Riverside and Anaheim, respectively, an undivided 1.79% and 1.66% interest in the Construction Agreement as it pertains to Units 2 and 3. Riverside and Anaheim acquire all rights and assume all duties and obligations of a "company" under the Construction Agreement, which shall be amended to provide for payment by Riverside and Anaheim of their proportionate shares of expenses.

Operating Agreement

The parties shall execute an Operating Agreement, covering the operation and maintenance of Units 2 and 3, which shall be accomplished in substantially the same manner and terms and conditions as the Unit 1 Operating Agreement provides for Unit 1. Edison will be operating agent for Units 2 and 3 and shall act as principal on its own behalf and as agent for the other parties.

Each of the parties shall be entitled to their proportionate share of the benefits and bear their proportionate share of the burdens incurred by Edison and San Diego in the performance of their duties under the agreements entered into by them for the construction, operation and maintenance of Units 2 and 3 and the common facilities.

Billing and Payment

Riverside and Anaheim will reimburse Edison within fifteen (15) days after receipt of invoice for construction costs incurred prior to execution of the Participation Agreement. Construction costs incurred after date of execution shall be paid in the manner prescribed in the Construction Agreement. Until such time as direct payment arrangements are made, Edison will bill Riverside and Anaheim for their proportionate share of costs of all project easements, plant site easements, the Units 2 and 3 Off-Shore Land Easement Lease and taxes and assessments.

Riverside and Anaheim will reimburse Edison for production costs of the common facilities paid by Edison and for the acquisition, rental and development expenses incurred by Edison within ten (10) days after execution of the Participation Agreement.

Riverside and Anaheim will reimburse Edison for costs incurred to effect their participation in Units 2 and 3 each month within fifteen (15) days after receipt of invoice.

Payments not made on or before the due date will be payable, with interest accrued at a rate of 10% per annum or the maximum rate of interest, whichever is less.

Administration

Anaheim and Riverside shall designate representatives in accordance with Section 7 of the Construction Agreement within ten (10) days after execution of the Participation Agreement. Rights and obligations set forth in Section 7 will become effective when Riverside and Anaheim begin paying funds pursuant to the billing and payment procedures set out above.

Liability and Insurance

The provisions of Sections 8 and 9 of the Construction Agreement shall apply to the Participation Agreement except as follows:

The term "company" shall include Edison, San Diego, Riverside, and Anaheim. The percentages to be paid as set forth in Sections 9.5 and 9.7 of the Construction Agreement shall be changed to Edison — 76.55%, San Diego — 20.00%, Riverside — 1.79%, and Anaheim — 1.66%.

Riverside and Anaheim will be added as named insureds on those policies of insurance presently in effect. Each will make application to Nuclear Mutual Limited, to become member insureds under the policies of insurance presently in effect for San Onofre Units 2 and 3 for (a) all risk-builders' risk insurance covering loss or damage to project work under course of construction, and (b) nuclear property damage insurance. If application for such insurance is accepted, Riverside and Anaheim shall maintain the policies through the term of the Participation Agreement. If the application is not accepted, Riverside and Anaheim will each secure and maintain insurance coverage from the Nuclear Energy Liability-Property Insurance Association and the Mutual Atomic Energy Reinsurance Pool, or their equivalent.

Riverside and Anaheim agree to release Edison and San Diego from any and all liability resulting from damage to, or loss or use of, Units 2 and 3, which is a result of the construction, operation or maintenance of Unit 1, the Edison Switchyard, the San Diego Switchyard, the Interconnection Facilities, or any additional generating units. Edison and San Diego release Riverside and Anaheim from any and all liability resulting from damage to or loss of use of Unit 1, which is the result of the construction, operation or maintenance of Units 2 or 3, or any additional generating units.

Nuclear Fuel

The Project Director, Edison, will make arrangements for the supply of nuclear fuel. In doing so, it will negotiate, execute, administer, perform and enforce nuclear fuel agreements as its deems necessary or appropriate. The proposed Nuclear Fuel Agreements will be submitted to the coordinating representatives for approval prior to execution; provided, that any Nuclear Fuel Agreement may be executed by the Project Director without its being submitted to the coordinating representatives as long as obligations of the parties are consistent with the Nuclear Fuel Budget.

Except as otherwise provided in the Participation Agreement, costs incurred by the Project Director in connection with the nuclear fuel shall be shared by each party in proportion to its generation entitlement share. Each party will own an undivided interest in all nuclear fuel equal to its generation entitlement share and may determine its own method of financing. With certain limitations, any party may elect to provide directly all or a portion of its share of natural uranium (U_3O_8) concentrates if the election is communicated to the Project Director sufficiently in advance.

One year prior to each date on which natural uranium (U_3O_8) concentrates are scheduled to be delivered, the Project Director will notify all parties of the quantity and specifications of uranium concentrates required. Within one month of such notification each party will provide the Project Director with evidence that the party has firm commitments for providing the required uranium. If such evidence is not satisfactory, the Project Director may proceed to arrange for delivery of the deficient party's uranium concentrates and the cost shall be billed to the deficient party as incurred. If the Project Director is unable to arrange for the uranium to cover a deficient party's commitment, then party shall be subjected to an appropriate reduction in its entitlement to the Net Energy Generation during the cycle. Each party shall pay its proportionate share of the total amount due for the purchase of nuclear fuel in advance of the date of which payments therefor by the Project Director become due.

Taxes

All taxes or assessments levied against each party's ownership or beneficial interest in San Onofre shall be that party's sole responsibility. Riverside and Anaheim shall reimburse Edison or San Diego for all taxes which are levied against Edison or San Diego as a result of the transfer to Riverside and Anaheim of a portion of Edison's ownership interest in Units 2, 3 or the common facilities. These taxes shall not include any tax on capital gains which may result from such transfer.

Termination

Riverside and/or Anaheim may terminate the Participation Agreement if unable to attain any required approval from regulatory and other authorities. If construction of Units 2 and 3 is not continued by the remaining parties, the accumulated construction costs incurred by the terminating party shall be borne by such terminating party. If construction is continued Edison shall acquire the terminating party's interest in San Onofre and shall reimburse such terminating party for its incurred construction costs.

Additional Generating Units

The parties reserve any right to participate in any additional generating unit at San Onofre, provided, that Riverside and Anaheim shall neither be granted nor denied participation rights by reason of any provision of the Participation Agreement. If additional generating units are constructed, interests in the project easements shall be reallocated among the participants.

Uncontrollable Forces

No party will be considered in breach of any obligation other than the obligation to pay money, to the extent failure of performance is due to an uncontrollable force as defined in the Participation Agreement. Any party unable to fulfill obligations by reason of an uncontrollable force shall exercise diligence to remove the inability with all reasonable dispatch.

Miscellaneous Provisions

Edison shall, within 12 months after receipt of payment from Riverside and Anaheim of Edison's costs in connection with the construction of Units 2 and 3, procure releases of the interest transferred from the lien of Edison's trust indenture and deliver to Riverside and Anaheim a bill of sale covering their respective ownership interests in Units 2 and 3.

Each party will be responsible for making arrangements necessary to transmit its entitlement of San Onofre power from San Onofre to its electric system. Except as provided in the Participation Agreement, Riverside and Anaheim are each responsible for obtaining from all regulatory authorities such authorizations and approvals as are necessary for its participation in the construction and operation of San Onofre and its performance of the provisions of the Participation Agreement.

Each party waives the right to seek partition of San Onofre and the Project Easements. Each further agrees that it will not resort to any action at law or in equity to partition the same. Before any party may assign to any entity, other than another party, any or all its interests in Units 2 or 3, the other parties each shall have the right of first refusal.

Riverside and Anaheim have the right to audit the books and records of Edison directly pertaining to Units 2 and 3, the common facilities and the plant site. If any errors are revealed by such inspection appropriate adjustments will be made.

SUMMARY OF THE EDISON-ANAHEIM SAN ONOFRE TRANSMISSION SERVICE AGREEMENT

The following is a general summary of certain provisions of the Edison-Anaheim San Onofre Transmission Service Agreement (the "Agreement"). Such summary does not purport to be complete and accordingly is qualified by reference to the full text of the Agreement, copies of which may be obtained from the City, upon written request.

Purpose

The purpose of the Agreement is to provide transmission of Anaheim's share of the energy from the Edison Switchyard at San Onofre Nuclear Generating Station to Anaheim's point of delivery.

Term

The Agreement shall become effective on the date following execution by the parties when accepted for filing by the Federal Energy Regulatory Commission. The Agreement shall remain in effect for 50 years unless terminated sooner by (i) written agreement of the Parties; (ii) termination of the Integrated Operations Agreement; or (iii) termination of Units 2 and 3 ownership or operating agreements. If notice of termination of the Integrated Operations Agreement is given by either party, the parties shall take actions to develop a new agreement for furnishing the services referred to in the Settlement Agreement. Edison has signed the Agreement and the City will sign upon delivery of the 1980 Bonds.

Transmission Service

Except as modified in the Agreement, transmission service shall be provided in accordance with the Contract Rate TN. Service shall commence on the Date of Firm Operation for Unit 2 at which time Contract Capacity shall be 18.26 megawatts, the City's share of the expected maximum rated capacity for Unit 2. On the Date of Firm Operation for Unit 3, Contract Capacity shall be increased by 18.26 megawatts, the City's share of the expected maximum rated capacity for Unit 3, and Contract Capacity shall, for each unit, be 18.26 megawatts.

Edison will accept delivery of Anaheim's Unit 2 and Unit 3 energy at Edison's 220-kV buses at San Onofre at rates of delivery not exceeding Contract Capacity, and will simultaneously deliver a like amount of energy less transmission losses to Anaheim at the Point of Delivery. The Point of Delivery is Anaheim's Lewis Substation. During times when Anaheim may be required to provide its share of the auxiliary power requirement at San Onofre, Edison will accept deliveries from Anaheim at the Point of Delivery and simultaneously deliver the like amount less transmission losses to Edison's 220-kV buses at San Onofre to enable Anaheim to meet its requirements.

Edison reserves the right to temporarily interrupt or curtail services (1) upon reasonable advance notice to Anaheim to make repairs or modifications or to perform maintenance work, (2) without notice to Anaheim if such interruption or curtailment is because of an Uncontrollable Force.

Charges and Transmission Losses

Charges will be made in accordance with the rates set forth in Contract Rate TN. Circuit mileage is agreed to be 47.4 miles, subject to change. No additional charge shall be made for auxiliary power requirements.

Transmission losses will be determined in accordance with the rates set forth in Contract Rate TN and using the circuit mileage agreed to above.

Edison reserves the right in furnishing transmission service to file with the Federal Energy Regulatory Commission for changes in rates, charges, classification, or services, or any rule, regulation or contract as provided in the Integrated Operations Agreement.

Billing and Payment

Prior to the 15th day of December of each year, Edison will render a bill to Anaheim for services to be provided during the following year. One-twelfth of such annual charge shall be due amd payable by Anaheim on the 15th day of each month. Payments which are not made in full by the due date shall accrue interest at 10% per annum on the unpaid balance.

Integration Agreement Provisions

Provisions of the Integrated Operations Agreement covering liability, arbitration, regulatory authority, uncontrollable forces, governing law, notices, and other matters, apply also to this Agreement.

SUMMARY OF THE INTEGRATED OPERATIONS AGREEMENT

The following is a general summary of certain provisions of the Integrated Operations Agreement (the "Agreement"). Such summary does not purport to be complete and accordingly is qualified by reference to the full text of the Agreement, copies of which may be obtained from the City, upon written request.

Purpose

The City has executed the Agreement with Edison pursuant to which the Project will be integrated and operated for the benefit of the City. In order to more efficiently meet the power requirements and obtain operational economies on their respective systems, the City and Edison agreed to integrate their present and future Resources. The Agreement is intended to provide for Edison to furnish the capacity and energy necessary to meet the City's load, to the extent not provided by City integrated resources.

Term

The Agreement was signed by Edison and the City on November 29, 1977 and became effective on the date it was accepted for filing by the Federal Energy Regulatory Commission and shall remain in effect for 50 years, unless terminated (i) by written agreement of the parties, (ii) upon 30 days' advance written notice by the City, to Edison, if no City Capacity Resource has been accepted for integration, (iii) upon not less than 10 years advanced written notice from one party to the other, or (iv) upon 5 years advance written notice from the City to Edison if Edison tenders for filing a change in rates which effects Integrated Operations, and which creates a substantial detriment to the City. If notice of termination is given by either party, the parties shall commence to negotiate in good faith a new arrangement for the furnishing of services, to become effective upon termination of the Agreement.

Integration of Resources

The City may construct or acquire and integrate a Resource as a City Capacity Resource to meet all or part of its Firm Load, and Edison shall use its best efforts to intergrate such proposed City Capacity Resource in accordance with the qualifications contained in the Agreement.

Scheduling and Dispatching

Edison, acting as the City's agent, shall provide scheduling and dispatching services for City Capacity Resources and City Transmission Facilities.

Reserve Obligations

City's contribution to installed reserves required to provide reliable electric service to the combined electrical requirements of the parties is deemed to be a percentage of the sum of the kilowatt capability of City Capacity Resources. The percentage for any year shall be equal to the arithmetic average of the five annual reserve margins planned by Edison for its resources for the next five consecutive years.

Partial Requirements Service

Edison shall make available and deliver capacity and energy to the City under the Partial Requirements Rate then in effect with the Federal Energy Regulatory Commission. The City is billed under the Partial Requirements Rate for its maximum peak demand during the billing period, less the Capacity Credit in effect at the time such maximum peak demand occurs. The Capacity Credit is equal to the rated capabilities of the City Capacity Resources minus the City contribution to installed reserves. The amount of the partial requirements energy to be purchased in any billing period shall equal the total energy requirement of the City's load, minus the greater of the amount of energy scheduled and dispatched from City Capacity Resources, or the amount of energy capability associated with the effective Capacity Credit.

Replacement Capacity and Contract Energy

If a City Capacity Resource is unavailable for 70 or more consecutive days, or for 100 or more non-consecutive days during a 180 consecutive day period, the City must provide replacement capacity by first withdrawing a number of kilowatt-days from the Scheduled Maintenance Account for that City Capacity Resource. After the scheduled maintenance account for a City Capacity Resource is exhausted, the City may obtain replacement capacity by purchase from one or more third parties outside the Edison Control Area, or Edison, or both. When a City Capacity Resource is not available, the City shall purchase Contract Energy from Edison, which is the amount of energy capability associated with the capacity credit, less the amount of energy received from City Integrated Resources. The Cost of Contract Energy is derived by utilizing Edison's fuel cost for conventional oil-fired, combustion turbine and combined-cycle generation plus the operating and maintenance costs associated with the production of such energy.

Surplus Capacity and Excess Energy from City Capacity Resources

Edison shall purchase from the City surplus capacity and associated energy from any City Capacity Resource when the City, upon 12 months advanced written notice to Edison, shall declare such capacity and energy to be surplus to the City's estimated load during the period of sale. Edison shall pay the City for such capacity and associated energy at a price which shall fully compensate City for its costs associated with such City Capacity Resources.

When energy is dispatched from one or more City Capacity Resources which exceeds the requirements of City's load in any hour, such excess energy shall be purchased by Edison. The charge for such energy shall be City's incremental costs of that City Capacity Resource, plus 15% of such costs.

To the extent a City Capacity Resource is available, but not dispatched by Edison, City may sell energy associated with such City Capacity Resource to third parties outside the Edison Control Area.

Transmission Service

Edison shall provide, upon City ... equest, firm transmission service for capacity or energy, or both, associated with City Capacity Resourc... Transmission Service shall be provided either on Edison's 220 kV network or on a point-to-point basis wher... smission service is to be provided outside the 220 kV network but within Edison's Certificated Service Are... ison shall use its best efforts to provide transmission service where a City requests transmission service ... of Edison's Certificated Service Area.

Transmission service shall be provided in ac... nce with rates on file, and approved by the Federal Energy Regulatory Commission.

Change of Rates

In general, with respect to the rates charged by Edison fo... rtial Requirements Service, Replacement Capacity and Contract Energy, and Transmission Service, Edis... erves the right to file with the Federal Energy Regulatory Commission for a change in rates, charges an... of service provided that no change shall be made which is inconsistent with the Agreement or any Integration Agreement. Edison's right to file for a change in rates with respect to Partial Requirements Service is subject to certain limitations when the Partial Requirements Rate becomes different from the All Requirements Rate. Thereafter, changes in the rate design of the Partial Requirements Rate are also subject to certain limitations. Edison has the right to change the rates, charges and conditions relating to Replacement Capacity and Contract Energy, provided that no change shall be inconsistent with the Agreement or any Integration Agreement. Edison may also change the wording contained in the Agreement which describes how Replacement Capacity and Contract Energy charges are calculated, but such changes may not become effective for 3 years after the filing or a Final Order of the Commission, whichever occurs first.

Edison reserves the right to change the rates, charges and conditions of service with respect to the furnishing of Transmission Service, provided that no change shall be inconsistent with the Agreement or any Integration Agreement. Moreover, any change as to wording in any Transmission Service Agreement may not become effective for 2 years after the filing or until a Final Order of the Commission, whichever occurs first.

SUMMARY OF THE SUPPLEMENTAL AGREEMENT FOR THE INTEGRATION OF ANAHEIM'S ENTITLEMENTS IN SAN ONOFRE UNITS 2 AND 3

The following is a general summary of certain provisions of the Supplemental Agreement for the Integration of Anaheim's Entitlements in San Onofre Units 2 and 3 (the "Supplemental Agreement"). Such summary does not purport to be complete and accordingly is qualified by reference to the full text of the Supplemental Agreement, copies of which may be obtained from the City, upon written request.

The Supplemental Agreement between the City and Edison is supplemental to the Integrated Operations Agreement and does not amend or supersede it except to the extent that terms therein are inconsistent. The Supplemental Agreement provides that the City's entitlements in the San Onofre Nuclear Generating Station, Units 2 and 3 will be integrated.

Integration

Anaheim's entitlements in Units 2 and 3 shall be integrated and Anaheim shall receive capacity credit in accordance with the Integrated Operations Agreement. Anaheim's Unit 2 entitlement shall become a source of Rated Capability on October 1, 1980, or the Date of Firm Operation for Unit 2, whichever is later and Anaheim's Unit 3 entitlement shall become a source of Rated Capability on January 1, 1982, or the Date of Firm Operation for Unit 3, whichever is later.

Determination of Anaheim's Rated Capability

Rated Capability of Anaheim's entitlements shall be equal to 1.66% of the Rated Capability rating of Units 2 and 3, respectively. The Rated Capability shall be equal to the effective operating capacity of each unit, and is planned for 1,100 megawatts for each unit.

Anaheim's Election to Pay for Energy When Units Are Available But Not Dispatched

To the extent that Units 2 and 3 are available, but not dispatched by Edison, the City may elect to pay for the amount of energy associated with its capacity credit at the cost of Contract Energy or the Incremental Cost of Unit 2 and 3 energy. Anaheim has elected to pay for energy associated with its entitlements in Unit 2 and 3 at City Incremental Cost. Anaheim may change its election to pay at Contract Energy Cost or City Incremental Cost upon either three years notice to Edison or when a change in a Contract Energy Cost formula has become effective. The City Incremental Cost is derived by adding the cost of fuel to other production costs and subtracting transmission losses.

Effective Date, Term and Termination

The Supplemental Agreement is effective on the date following the execution by both parties when accepted for filing by the Commission. The Supplemental Agreement has been signed by Edison and the City will sign upon delivery of the 1980 Bonds. The Supplemental Agreement is to remain effective for 50 years, except that it shall terminate sooner upon, (1) written agreement of the parties to terminate the Supplemental Agreement, or (2) termination of the Integrated Operations Agreement, or (3) termination of the Units 2 and 3 ownership or operating agreements.

If notice of termination of the Integrated Operations Agreement is given by either party, the parties shall take actions to develop a new arrangement for furnishing the services which are provided for in the Supplemental Agreement.

Price Waterhouse & Co.

660 NEWPORT CENTER DRIVE
NEWPORT BEACH CALIFORNIA 92660
714 640 9200

APPENDIX F

REPORT OF INDEPENDENT ACCOUNTANTS

To The Honorable City Council
City of Anaheim, California

In our opinion, the accompanying balance sheet and the related statements of income, changes in retained earnings and of changes in financial position present fairly the financial position of the Electric Utility Fund of the City of Anaheim at June 30, 1979 and 1978, and the results of its operations and the changes in its financial position for the years then ended, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Price Waterhouse & Co.
November 16, 1979
Newport Beach, California

CITY OF ANAHEIM
ELECTRIC UTILITY FUND
BALANCE SHEET

	June 30, 1979	June 30, 1978
	(In thousands)	
ASSETS		
Utility plant:		
Transmission	$11,058	$11,039
Distribution	37,231	32,183
General	1,708	1,670
Construction work in progress	1,890	1,452
	51,887	46,344
Less — accumulated depreciation	14,785	13,633
	37,102	32,711
Restricted cash and investments (Note 3)	4,724	4,521
Current assets:		
Cash and investments	7,894	4,121
Customer and other accounts receivable, less allowance for doubtful accounts of $180,000 in 1979 and $160,000 in 1978	4,425	4,728
Accrued interest receivable	186	
Materials and supplies, at average cost	870	1,479
Prepayments (Note 6)	2,457	3,885
	15,832	14,213
Other assets:		
Prepaid electric power (Note 6)		4,838
Unamortized project costs (Note 5)	2,427	2,851
Unamortized debt expenses	57	68
	2,484	7,757
Total assets	$60,142	$59,202
EQUITY, LIABILITIES AND OTHER CREDITS		
Equity:		
Fund balance transferred	$14,629	$14,629
Retained earnings	14,845	13,670
Total equity	29,474	28,299
Revenue bonds, less current portion (Note 3)	14,100	18,100
Total capitalization	43,574	46,399
Current liabilities (payable from restricted assets):		
Current portion of revenue bonds	300	579
Accrued interest on bonds	248	273
	548	852
Current liabilities (payable from current assets):		
Current portion of revenue bonds	3,700	3,221
Accounts payable and accrued expenses	10,330	8,290
Customer deposits	392	386
	14,422	11,897
Total current liabilities	14,970	12,749
Contributions in aid of construction	1,598	54
Total equity, liabilities and other credits	$60,142	$59,202

See accompanying Notes to Financial Statements

CITY OF ANAHEIM
ELECTRIC UTILITY FUND
STATEMENT OF INCOME

	Year ended June 30, 1979	Year ended June 30, 1978
	(In thousands)	
Operating revenues:		
Sales of electric energy (Note 7)	$70,842	$64,038
Other operating revenues	331	815
Total operating revenues	71,173	64,853
Operating expenses:		
Cost of purchased power	59,198	51,747
Other operations	3,657	2,981
Maintenance	2,036	1,677
Depreciation	1,358	1,395
Amortization of project costs (Note 5)	302	118
Total operating expenses	66,551	57,918
Operating income	4,622	6,935
Other income (expense):		
Interest income	869	446
Interest expense, including amortization of debt expenses	(692)	(725)
	177	(279)
Net income	$ 4,799	$ 6,656

STATEMENT OF CHANGES IN RETAINED EARNINGS

	1979	1978
Balance at beginning of year	$13,670	$ 9,582
Net income for the year	4,799	6,656
	18,469	16,238
Transfer to the general fund of the City	(3,624)	(2,568)
Balance at end of year	$14,845	$13,670

See accompanying Notes to Financial Statements

CITY OF ANAHEIM
ELECTRIC UTILITY FUND
STATEMENT OF CHANGES IN FINANCIAL POSITION

	Year ended June 30, 1979	1978
	(In thousands)	
Financial resources were provided by:		
Operations —		
Net income	$ 4,799	$ 6,656
Charges to income not involving working capital —		
Provision for depreciation	1,358	1,395
Amortization of project costs	302	118
Amortization of debt expenses	11	11
Resources provided by operations	6,470	8,180
Decrease in prepaid electric power	4,838	4,412
Contributions in aid of construction	1,544	
Decrease in unamortized project costs	122	
Disposal of plant and equipment		496
Decrease in restricted cash and investments		41
	12,974	13,129
Financial resources were used for:		
Expenditures for plant and equipment	5,665	4,143
Revenue bonds becoming current	4,000	3,800
Transfer to the general fund of the City	3,624	2,568
Increase in restricted cash and investments	203	
Other	84	
	13,576	10,511
Increase (decrease) in working capital	($ 602)	$ 2,618
Increase (decrease) in components of working capital:		
Cash and investments	$ 3,773	$ (116)
Customer and other accounts receivable	(303)	1,538
Accrued interest receivable	186	
Materials and supplies	(609)	299
Prepayments	(1,428)	619
Net change in current assets	1,619	2,340
Current portion of revenue bonds	(200)	(200)
Accrued interest on bonds	25	21
Accounts payable and accrued expenses	(2,040)	529
Customer deposits	(6)	(72)
Net change in current liabilities	(2,221)	278
Increase (decrease) in working capital	($ 602)	$ 2,618

See accompanying Notes to Financial Statements

CITY OF ANAHEIM

ELECTRIC UTILITY FUND

NOTES TO FINANCIAL STATEMENTS

NOTE 1 — Summary of Significant Accounting Policies:

Basis of accounting

The Electric Utility Fund was established June 30, 1971, at which time the portion of the City of Anaheim's General Fund equity relating to electric utility operation was transferred to Electric Utility equity. The financial statements of the Electric Utility are presented in conformity with generally accepted accounting principles and accounting principles and methods prescribed by the Federal Energy Regulatory Commission (FERC). The Electric Utility is not subject to the regulations of such commission.

Utility plant and depreciation

The cost of additions to utility plant and of replacements of retirement units of property is capitalized. Utility plant is recorded at cost, or in the case of contributed plant, at fair value at the date of the contribution, except that assets acquired prior to July 1, 1977, are recorded at appraised historical cost. Cost includes labor; materials; allocated indirect charges such as engineering, supervision, construction and transportation equipment, retirement plan contributions and other fringe benefits, and; certain administrative and general expenses. The cost of relatively minor replacements is included in maintenance expense. When assets are retired the remaining net book value or any excess or deficiency of sales proceeds over (or under) net book value at the date of sale is recorded in accumulated depreciation.

Depreciation of utility plant is provided by the straight line method based on the estimated service lives of the properties:

Transmission and distribution plant	20 to 75 years
Other plant and equipment	3 to 50 years

Depreciation on contributed assets is charged directly to contributions in aid of construction.

Cash and investments

The City pools idle cash from all funds for the purpose of increasing income through investment activities. Investments are carried at cost, which approximates market value. Interest income on investments is allocated to the various funds of the City on the basis of average daily cash and investment balances.

Revenue recognition

Revenues are recognized as billed to customers. Billings are on a cyclical basis and the Electric Utility does not accrue revenues for electricity sold but not billed at the end of a fiscal period. Residential and the smaller commercial accounts are billed on a bimonthly basis; all others are billed monthly.

Shared operating expenses

The Electric Utility shares certain administrative functions with the Water Utility. Generally, the cost of these functions is allocated on the basis of benefits provided to the Electric and Water Utilities.

Debt expenses

Debt premiums, discount and issue expenses are deferred and amortized to income over the lives of the related bond issues.

Pension plan

All full-time City employees are members of the State of California Public Employee's Retirement System. The City's policy is to fund all pension cost accrued; such costs to be funded are determined annually as of July 1 by the System's actuary. Unfunded prior service cost is being funded over 25 years ending June 30, 2000.

Vacation and sick leave

The City does not accrue accumulated vacation or sick leave, but rather expenses these costs as paid. It is the policy of the City to pay all accrued vacation pay when an employee retires or is terminated, and one-fourth of the accrued sick leave when an employee retires. At June 30, 1979, accumulated unused vacation and sick leave did not exceed a normal year's accumulation.

Transfers to the general fund of the City

Article XII of the City Charter was amended by a vote of the electorate effective December 27, 1976 to provide that transfers to the General Fund of the City in fiscal year 1977-78 shall be equal to, or less than 8% of the gross revenue earned in fiscal year 1976-77. This percentage was reduced to 6% in fiscal year 1978-79 for gross revenue of 1977-78, and to 4% in fiscal year 1979-80 and succeeding years. Such transfers are not in lieu of taxes and are recorded as distributions of retained earnings.

NOTE 2 — Accounting and Classification Changes:

As of July 1, 1978, the City elected to report its Electric Utility Fund under FERC industry accounting guidelines. In accordance with the guidelines, depreciation on assets acquired from contributions in aid of construction is not reflected in net income but rather is charged directly to contributions in aid of construction. This change had no cumulative effect on retained earnings and an insignificant effect on net income for the current year.

For the year ended June 30, 1979, certain other account classifications have been changed to reflect recommendations set forth in the FERC guidelines. For comparative purposes, prior year balances have been reclassified to conform to the 1978-79 presentation.

NOTE 3 — Revenue Bonds

The Electric Utility Fund is indebted under three revenue bond issues as follows:

	June 30, 1979	June 30, 1978
Electric Revenue Bonds, Issue of 1972, 4.9263%, issued March 28, 1972 in the amount of $8,000,000, maturing serially to July 1, 1992, in annual principal installments of $300,000 to $675,000, total debt service of $8,914,000 to maturity	$ 6,525,000	$ 6,800,000
Electric Revenue Bonds Issue of 1976, 6.07%, issued April 27, 1976 in the amount of $6,000,000, maturing serially to May 1, 2006, in annual principal installments of $100,000 to $400,000, total debt service of $11,939,975 to maturity	5,750,000	5,850,000
Electric Revenue Bonds, Second Issue (Subordinated) of 1976, 4.8259%, issued June 8, 1976 in the amount of $12,500,000, maturing serially to December 1, 1980 with remaining principal installments of $3,600,000 and $2,225,000 in fiscal years 1980 and 1981, total debt service of $6,119,038 to maturity	5,825,000	9,250,000
	18,100,000	21,900,000
Less current portion	4,000,000	3,800,000
	$14,100,000	$18,100,000

In accordance with the 1972 bond resolution, a reserve for maximum annual debt service has been established and a reserve for renewal and replacement is being accumulated to a maximum of 2% of the book value of the utility plant.

The three bond issues require the establishment of a bond payment reserve by accumulating monthly, one-sixth of the interest which will become due and payable on the outstanding bonds within the next ensuing six months and one-twelfth of the principal amount which will mature and be payable on the outstanding bonds within the next twelve months (six months for the $12,500,000 issue).

Restricted cash and investments includes reserved amounts as well as undisbursed bond proceeds as follows:

	June 30, 1979	June 30, 1978
Held by fiscal agent:		
Maximum annual debt service reserve	$ 682,000	$ 682,000
Bond service account	418,000	449,000
Other:		
Maximum annual debt service	404,000	404,000
Bond service account	682,000	402,000
Renewal and replacement reserve	742,000	712,000
Restricted bond proceeds	1,796,000	1,872,000
	$ 4,724,000	$ 4,521,000

NOTE 4 — Operating Expenses

Operating expenses shared with the Water Utility amounted to $3,823,000 and $2,662,000 for the years ended June 30, 1979 and June 30, 1978, respectively, of which $2,553,000 and $1,624,000 was allocated to the Electric Utility.

NOTE 5 — Unamortized Project Costs

The City plans to participate in various power generation projects with other agencies. Unamortized project costs includes $1,213,000 which represents advance payments to participating agencies for preliminary engineering and environmental impact studies for the related projects.

During 1978, two projects to which the City had advanced $1,382,000 were terminated without benefits accruing to the City. The $1,382,000 is being amortized to expense over the ensuing five years, of which $1,214,000 remained unamortized at June 30, 1979.

NOTE 6 — Prepaid Electric Power

The City entered into an agreement with Nevada Power Company on May 25, 1976 to purchase electric power over the next four years. On July 1, 1976 the City used $12,500,000 of revenue bond proceeds to make a partial prepayment to Nevada Power Company for energy to be supplied. In accordance with the terms of the agreement, beginning July 1, 1977, the prepayment has been offset against billings from Nevada Power Company for electric power purchases.

NOTE 7 — Sales of Electric Energy

Effective June 1, 1979, rates for all classes of service were increased approximately 4.7 percent. The rate resolution established for the first time an energy cost adjustment formula by which billings to customers are subject to adjustment, up or down, to reflect variations in the cost of wholesale power to the Electric Utility.

NOTE 8 — Pension Plan

The Electric Utility has a contributory pension plan for its full-time employees under the State of California Public Employee's Retirement System. The Electric Utility's cost of benefits funded for 1979 and 1978 were approximately $282,000 and $293,000, respectively. Information as to the actuarially computed value of vested benefits over the related pension fund assets is not available.

NOTE 9 — Self-Insurance Programs

Effective September 1, 1974, the Electric Utility became part of a City of Anaheim-adopted self-insured workers' compensation program which is administered by a service agent. Effective July 1, 1977, the City (including the Electric Utility) became self-insured for the first $500,000 on each general liability claim. Costs relating to the litigation of claims are charged to expenditures as incurred.

NOTE 10 — Commitments and Contingencies

The Electric Utility's budget for the fiscal year 1979-80 provides for capital expenditures of approximately $6,468,000 and substantial commitments have been made in connection therewith. The Electric Utility plans to sell bonds of approximately $55,000,000 to finance its participation in the San Onofre Nuclear Generating Station.

A number of claims and suits are pending against the Electric Utility for alleged damages to persons and property and for other alleged liabilities arising out of matters usually incident to the operations of a utility business such as that of the Electric Utility. In the opinion of management, the uninsured liability under these claims and suits would not materially affect the financial position of the Electric Utility as of June 30, 1979.

CITY OF ANAHEIM ELECTRIC UTILITY FUND

Unaudited Financial Statements for the 10 Months Ended A : 30, 1980 and 1979.

CITY OF ANAHEIM
ELECTRIC UTILITY FUND
BALANCE SHEET
(Unaudited)

	April 30, 1980	April 30, 1979
	(In thousands)	
ASSETS		
Utility plant:		
Transmission	$ 11,075	$ 11,054
Distribution	40,396	36,174
General	1,715	1,677
Construction work in progress	2,068	1,753
	55,254	50,658
Less — accumulated depreciation	(15,990)	(14,752)
	39,264	35,906
Restricted cash and investments	6,007	5,899
Current assets:		
Cash and investments	13,469	6,010
Customer and other accounts receivable, less allowance for doubtful accounts	5,429	3,960
Accrued interest receivable	412	87
Materials and supplies, at average cost	981	974
Prepayments	7	3,759
	20,298	14,790
Other assets:		
Unamortized project costs	2,327	2,417
Unamortized debt expenses	48	59
	2,375	2,476
Total assets	$ 67,944	$ 59,071
EQUITY, LIABILITIES AND OTHER CREDITS		
Equity:		
Fund balance transferred	$ 14,629	$ 14,629
Retained earnings	21,908	14,459
Total equity	36,537	29,088
Revenue bonds, less current portion	11,550	16,000
Total capitalization	48,087	45,088
Current liabilities (payable from restricted assets):		
Current portion of revenue bonds	325	300
Accrued interest on bonds	504	598
	829	898
Current liabilities (payable from current assets):		
Current portion of revenue bonds	4,125	3,600
Accounts payable and accrued expenses	11,827	7,800
Customer deposits	468	328
	16,420	11,728
Total current liabilities	17,249	12,626
Contributions in aid of construction	2,608	1,357
Total equity, liabilities and other credits	$ 67,944	$ 59,071

CITY OF ANAHEIM
ELECTRIC UTILITY FUND
STATEMENT OF INCOME
(Unaudited)

	Ten Months ended April 30, 1980	1979
	(In thousands)	
Operating revenues:		
Sales of electric energy	$74,599	$59,193
Other operating revenues	227	255
Total operating revenues	74,826	59,448
Operating expenses:		
Cost of purchased power	59,307	49,116
Other operations and maintenance	5,442	4,589
Depreciation	1,165	1,132
Amortization of project costs	268	251
Total operating expenses	66,182	55,088
Operating income	8,644	4,360
Other income (expense):		
Interest income	1,472	602
Interest expense, including amortization of debt expenses	(550)	(573)
	922	29
Net income	$ 9,566	$ 4,389

STATEMENT OF CHANGES IN RETAINED EARNINGS

	1980	1979
Balance at beginning of year	$14,845	$13,670
Net income for the period	9,566	4,389
	24,411	18,059
Transfer to the general fund of the City	(2,503)	(3,600)
Balance at April 30	$21,908	$14,459

CITY OF ANAHEIM — ECONOMIC BACKGROUND AND FINANCIAL INFORMATION

ECONOMIC BACKGROUND

The Bonds will not be secured by any pledge of ad valorem taxes or General Fund revenues but will be payable solely from the Gross Revenues of the City's Electric System. The financial and economic position of the City of Anaheim set forth below and on the following pages is included in the Official Statement for information purposes only, in the interest of giving a more complete description of the City.

General

The community of Anaheim was founded and incorporated in 1857, disincorporated in 1872, reincorporated in 1876, and reorganized in 1888. No change in organization took place until June 1964, when the local voters approved a City Charter. The City operates under the Charter and with a Council-Manager form of government. The five City Council members are elected to four-year terms in alternate slates of three and two every two years, with the Mayor being elected every two years. The Mayor presides over meetings of the Council and has one vote.

The Council appoints the City Manager, who heads the executive branch of government, implements Council directives and policies, and manages the administrative and operational functions through the various departmental heads, who are appointed by the City Manager.

Anaheim is located in northwestern Orange County, about 28 miles southeast of downtown Los Angeles and about 90 miles north of San Diego. The City lies on a coastal plain which is bordered by the Pacific Ocean on the west and the Santa Ana Mountains on the east.

The climate is generally characterized as sunny and mild with mean temperatures ranging between 53° in January and 72° in July. Rainfall averages about 14 inches per year. Afternoon humidity averages 45%-52% throughout the year.

Anaheim, Orange County's oldest and most populous city, is strategically situated in relation not only to Orange County's population but also to the economies of San Diego, Los Angeles, Riverside and San Bernardino Counties. Major freeways in and through the City conveniently locate industry to labor markets and recreation and commerce to consumers of a much broader area. The Santa Ana Freeway (Interstate 5) connecting Los Angeles and San Diego is the main artery traversing the City, and it connects in or near the City with the Artesia/Riverside (State Route 91), the Garden Grove (State Route 22), the Orange (State Route 57), and the Costa Mesa (State Route 55) freeways.

Anaheim is also served by three railroads, the Southern Pacific, the Santa Fe, and the Union Pacific, and numerous truck carriers in Southern California.

The major airports in the area include John Wayne (14 miles south), Ontario International (20 miles northeast), Los Angeles International (30 miles northwest) and Long Beach (14 miles west).

The City is served daily by various bus lines including the Orange County Transit District, the Southern California Rapid Transit District, Greyhound Lines, and Airport Coach Services, Inc.

City Council

JOHN F. SEYMOUR, JR., Mayor, was elected to his second two year term as Mayor of the City by a popular vote of the people in April of 1980. He was elected to a second consecutive four year term on the City Council in April of 1978. He has served his community as a planning commissioner and was president of the Anaheim Chamber of Commerce. He currently is President of the California Association of Realtors.

E. LLEWELLYN OVERHOLT, JR., Mayor *Pro Tem*, was elected to his first four year council term in April 1978. He has been a practicing attorney in Anaheim for 21 years and has served his community on a variety of special study committees and on commissions. He also has been active in civic affairs and is a past trustee of the Anaheim City School District.

BEN W. BAY, Councilman, elected to his first four year term on the City Council in April 1980. He had been unanimously appointed to the City Council on May 8, 1979 to fill an unexpired term. He was a member of the Anaheim Redevelopment Commission, served his community as chairman of the Charter Review Committee and has been active in a variety of community affairs.

MIRIAM KAYWOOD, Councilwoman, began her second term in April 1978. Mrs. Kaywood served as a planning commissioner and was active in civic affairs ranging from the cultural arts to municipal capital improvements prior to her initial four year c uncil term which began in April 1974.

DON R. ROTH, Councilman, elected to his second four year term on the City Council in April 1980. He was elected to his first council term April 1976. He has been active in civic affairs and was one of the original voting members of the City of Anaheim Charter Committee which authored the current City Charter.

City Management

WILLIAM O. TALLEY, City Manager, was named to the City's top administrative post July 9, 1976. Previously he was Assistant City Manager and was responsible for installation of Anaheim's "Management by Objectives" program. Mr. Talley came to the City in December, 1975 from a 20-year career with the City of Long Beach. His responsibilities in Long Beach included budget and research, data processing, intergovernmental relations, and a wide range of administrative services in such areas as transportation, oil properties and utilities.

GEORGE P. FERRONE, Finance Director, joined the City in August of 1977 with an extensive accounting background which included two years as vice president of financial affairs at Chapman College, Orange, California, controller of Lightcraft of California and management consulting supervisor for the accounting firm of Ernst & Whinney in Los Angeles. Mr. Ferrone is a member of the American Institute of Certified Public Accountants, the Municipal Finance Officer's Association of the United States and Canada, where he serves on the National Committee on Accounting, Auditing and Financial Reporting and the California Society of Municipal Finance Officers, where he serves on the Professional and Technical Standards Committee. The Finance Director's overall responsibilities are the following: centralized accounting functions; collecting all electric and power, water, sanitation and industrial waste charges; control and preparation of the City payroll; the budget; and purchasing and warehousing.

WILLIAM P. HOPKINS, JR., City Attorney, heads the legal staff representing the City. He was appointed by the City Council in October 1976. Mr. Hopkins joined the City as a Deputy City Attorney in 1968 and became an assistant in November of 1973. Mr. Hopkins has a law degree from the University of Southern California. He is a member of the American, California, Orange County and Los Angeles County bar associations. He also is a member of the Bar of the Supreme Court of the United States.

Population

Anaheim's land area remained at 3.7 square miles from 1900 through 1940. From 1940 to 1979, that area multiplied by 11.36 times to 42.04 square miles. Since World War II, immigration and, to a lesser extent, annexation have produced major population growth in Anaheim. The growth multiple was about 14.5 from 14,556 in 1950 to about 211,700 in 1980. Anaheim is California's eighth most populous City. The following chart indicates the growth in the area and population of the City since 1900 as well as that of the County.

CITY OF ANAHEIM AND ORANGE COUNTY
Area and Population

Year	City of Anaheim Square Miles	City of Anaheim Population	Average Annual Population Per Cent Change	Orange County Population	City Population Per Cent of County	Rank in Size of California Cities
1900	3.70	1,456	— %	19,696	7.4%	51
1910	3.70	2,628	8.1	34,436	7.6	66
1920	3.70	5,526	11.0	61,375	9.0	42
1930	3.70	10,995	9.9	118,674	9.3	44
1940	3.70	11,031	—	130,760	8.4	NA
1950	4.40	14,556	3.2	216,224	6.7	68
1960	27.34	104,184	61.6	703,925	14.8	12
1970	33.10	166,701	6.0	1,420,386	11.8	8
1973	37.98	186,200	7.9	1,584,259	11.8	8
1974	38.62	187,400	0.6	1,646,314	11.4	8
1975	38.84	191,800	2.3	1,684,462	11.4	8
1976	38.97	196,400	2.4	1,722,100	11.4	8
1977	39.40	200,100	1.9	1,768,000	11.3	8
1978	39.95	204,800	2.3	1,808,200	11.3	8
1979	42.04	208,500	1.8	1,851,000	11.3	8
1980	42.05	211,700	1.5	1,896,200	11.2	8

SOURCES: United States Bureau of the Census; California Department of Finance; City of Anaheim Planning Department.

Building Activity

According to the *1976 Anaheim Census*, prepared by the City Planning Department, the total number of dwelling units in the City increased from 56,216 in 1970 to 73,606 in 1976, an increase of 17,390 (31%). The trend toward a greater percentage of renter-occupied units has continued during the 1970's. In 1970 only 37.1% of all units were multiple; by 1976 approximately 47% of all dwelling units were multiple units.

The median listing price of owner-occupied single-family structures in 1979 in Anaheim was $122,900, compared to the County median of $155,670, according to the Walker and Lee Real Estate Research Section survey on residential resales, calculated from multiple listings. The *1976 Anaheim Census* indicated a median monthly payment for owner-occupied households enumerated of $209; median contract rent of $175 represented an increase of 28% from the 1970 median of $137.

During the five years 1975 through 1979, total valuation of all building permits issued by the City of Anaheim Building Division averaged about $171.8 million; total permits averaged 5,961 per year.

CITY OF ANAHEIM
Building Activities

	1979	1978	1977	1976	1975
Total Valuation (thousands)	$177,457	$155,031	$251,983	$175,162	$99,524
Total Permits Issued	4,882	6,036	7,301	6,516	5,073
New Construction					
Residential (thousands)	$ 67,166	$ 70,735	$152,997	$109,108	$64,616
Permits	365	625	1,775	1,652	1,277
Non-Residential (thousands)	$161,351	$138,391	$ 83,685	$ 52,838	$25,787
Permits	1,238	1,353	1,346	958	732
Additions and Alterations					
Residential (thousands)	$ 7,111	$ 7,529	$ 7,505	$ 6,174	$ 4,093
Permits	2,513	3,142	3,413	3,091	2,427
Other (thousands)	$ 8,696	$ 8,969	$ 7,796	$ 7,042	$ 5,028
Permits	642	792	767	815	637

New Dwelling Units

Total Residential Units	984	1,396	2,919	2,847	1,795

SOURCE: City of Anaheim Planning Department, Building Division.

Employment

No annual information is regularly compiled on employment and unemployment for the City alone. Employment in Orange County increased from about 773,000 in 1976 to about 1,019,000 in 1979, at an average annual rate of about 8.0%. The County unemployment rate was lower than that in the State in each of the past four years. The mobile resident labor force of Orange County is employed not only in the County but also in adjacent counties, such as Los Angeles. 1970 Census data indicated that about 44.9% of the City's population was in the civilian labor force, and that about 94.2% of that labor force was employed. The County by comparison had about 41.5% of its population in the civilian labor force and 94.7% of that labor force was employed.

ORANGE COUNTY
Employment, Unemployment and Labor Force(1)
Averages: 1976-79
(thousands)

	1979	1978	1977	1976
Employment	1,019.0	953.7	864.4	773.0
Unemployment	44.1	48.9	53.6	64.8
Civilian Labor Force	1,063.1	1,002.6	918.0	837.8
Unemployment Rate	4.1%	4.9%	5.8%	7.7%
State Unemployment Rate	6.2%	7.1%	8.2%	9.2%

(1) By place of residence, including workers involved in labor disputes.

SOURCE: State Employment Development Department.

The *1976 Anaheim Census* prepared by the City Planning Department, indicated a civilian labor force living within the City of 92,863. The percentages of Anaheim workers in different industries so reported were:

Industry	Per Cent of Workers
Services	24.4%
Manufacturing	23.7
Wholesale and Retail Trade	16.7
Government	10.1
Transportation, Communications and Utilities	9.0
Construction	8.5
Finance, Insurance and Real Estate	6.0
Agriculture	1.1
Mining	0.4

CITY OF ANAHEIM
Major Private Employers

Company	Number of Employees	Products
Rockwell International Corporation	8,000	Aircraft, Aerospace and Electronics
Disneyland	6,000	Recreation and Entertainment
Carl Karcher Enterprises	2,300	Fast Food Restaurants
Wrather Corporation	2,300	Hotels
Kwikset Division, Emhart Industries, Inc.	1,800	Residential Locksets and Powdered Metal Parts
Northrup Electro-Mechanical Division, Northrup Corporation	1,800	Aerospace Electronics
Interstate Electronics Corp., Division of A-T-O, Inc.	1,700	Electronics
Disneyland Hotel	1,400	Hotel, Restaurants and Shops
Anaheim Memorial Hospital	1,000	Hospital
General Automation, Inc.	900	Mini-Computers
California Computer Products, Inc.	800	Computer Products
United Parcel Service	800	Mail Delivery, Pick-Up
Anaconda Telecommunications	725	Telephone Equipment
Altec Division of Altec Corporation	700	Sound Products
Kaiser-Canyon General Hospital	700	Hospital
Taylor Bus Service	700	Transportation
Van Doren Rubber	700	Tennis Shoes
Martin Luther Hospital Medical Center	651	Hospital
Data Products Division of Lear Siegler, Inc.	630	Data Products
Southern California Gas Company	622	Natural Gas Distribution
Laura Scudders Division of Pet, Inc.	545	Snack Food Products
Topmost Foods, Inc., Division of Pinata Foods	500	Frozen and Convenience Foods
Unitax Division of Tymshare, Inc.	500	Computerized Income Tax Service

SOURCE: "Orange County Business", February/March, 1980.

Income

Total personal income of Orange County residents increased 60.4% from over $7.4 billion in 1971 to over $11.9 billion in 1975, the latter year being the most recent for which the U.S. Department of Commerce has published such data. The County share of total personal income in California increased from 7.8% in 1971 to 8.6% in 1975. On a per capita basis, the average annual rate of Orange County increase was

8.5% over the four-year period, from $5,040 in 1971 to $6,995 in 1975. The latter figure was approximately $400 greater than the State per capita income of $6,596.

The 1970 U.S. Census indicated that 11.2% of Anaheim families received income under $5,000 in 1969; 13.2% received $5,000-$7,999; 45.9% received $8,000-$14,999; and 29.7% received $15,000 and over. Comparable percentages reported in the *1976 Anaheim Census*, prepared by the City Planning Department, were 14.3%, 11.6%, 33.6%, and 40.4%. In 1975, 1970 Census comparison of Anaheim with Orange County and California shows the City to have had a significantly larger proportion of middle income families than both the other areas.

ORANGE COUNTY
Resident Personal Income
($000)

Source	1975	1974	1973	1972	1971
Net Labor and Proprietor's Income(1)	$ 6,515,602	$ 5,918,411	$ 5,329,193	$ 4,651,046	$ 4,104,118
Resident Adjustment(1)	2,560,182	2,268,503	1,929,167	1,820,082	1,707,497
Dividends, Interest, Rent	1,605,032	1,445,286	1,207,556	1,084,571	983,621
Transfer Payments	1,282,220	1,004,975	832,183	732,060	661,373
Total Resident Personal Income	$ 11,963,036	$ 10,637,175	$ 9,298,099	$ 8,287,759	$ 7,456,609
Per Capita	$6,995	$5,427	$5,809	$5,418	$5,040
California Resident Personal Income	$139,388,100	$126,955,682	$113,514,529	$102,949,604	$95,335,940
Per Capita	$6,596	$6,090	$5,497	$5,044	$4,711

(1) Net Labor and Proprietor's Income is by place of work and includes wage and salary and proprietor's income earned in Orange County, less personal contributions for social insurance. The Residence Adjustment, when added to Net Labor and Proprietor's Income by place of work, provides the net labor and proprietor's income by place of residence (i.e., Orange County).

SOURCE: Bureau of Economic Analysis, U.S. Department of Commerce; Regional Economics Information System.

Tourism and Community and Recreational Facilities

Tourism is a major industry in Anaheim. Much of that industry, including about 120 hotels and motels and over 275 restaurants, is located for convenience to the major local attractions: the Anaheim Stadium, the Anaheim Convention Center and Disneyland.

The Anaheim Stadium, financed and built by a non-profit corporation and leased to the City, has been expanded and consists of a 70,500 seat athletic stadium and supportive facilities. The stadium is the home of the California Angels, an American League baseball team, the Los Angeles Rams, a National Football League team, and the California Surf, a North American Soccer League team. The City also rents the stadium to others for concerts and exhibitions and utilizes it for civic events.

The Anaheim Convention Center, largest such facility west of the Mississippi River, is a multi-purpose convention/sports/concert hall complex covering approximately 53 acres of land.

The Anaheim Convention Center Betterment II Program represents the second major addition to this important convention center. This single-story, Type I construction addition, with 185,990 square feet of gross floor area, is on a 12.5 acre site to the south of the existing Anaheim Convention Center property. The facility includes a third exhibit hall of 100,000 sq. ft.; plus 21,000 sq. ft. for meeting rooms; ancillary space for a concession stand, storage areas, restrooms and a satellite kitchen; and offices. Movable wall panels are utilized to separate the meeting rooms so that various room configurations may be arranged to suit the exhibitors. This second addition, providing approximately 1,000 more parking spaces, will bring the total parking for the facility to approximately 4,000 spaces. Total square footage for the entire complex is now approximately 867,193 sq. ft.

The following table summarizes the number of conventions held at the Center, as well as estimated attendance and delegate expenditures for the past six years.

ANAHEIM CONVENTION CENTER

Year	Conventions	Attendance	Delegate Expenditures
1975	191	490,000	$ 98,000,000
1976	181	517,000	142,000,000
1977	161	475,000	166,000,000
1978	174	674,000	201,000,000
1979	147	476,000	178,500,000
1980(Actual and Estimated	149	675,000	270,000,000

SOURCE: Anaheim Area Visitor and Convention Bureau.

Disneyland occupies a 180 acre site in the City and is one of the major tourist attractions in the nation. Opened in 1955 with an original investment of $17,000,000, Disneyland today has a total capital investment exceeding $200,000,000. Approximately 10.8 million visitors passed through its gates in 1978.

The Disneyland Hotel has just completed a 450 room expansion for a total of 1,350 rooms. Construction is now under way for an 750 room Marriott Hotel across from the Convention Center, to be completed in 1981.

On May 6, 1980 the City of Anaheim entered into an agreement for exclusive right to negotiate with Hilton Hotels Corporation/Wrather Corporation for the construction of a four-story convention center hotel of approximately 1,500 guest rooms (including the approximately 500 guest rooms at the current Inn at the Park Hotel) located on property adjacent to the Anaheim Convention Center. Construction costs are currently estimated at $100,000,000. The parties anticipate the lease and development agreements for the hotel project will be executed no later than November 6, 1980.

Orange County is a major tourist center of Southern California. Forty-four miles of shorelines with more than twenty publicly maintained beach areas provide year-round aquatic activities.

In Anaheim, there are two 18-hole golf courses, ten community parks, four of which contain major athletic facilities, and 32 neighborhood parks and playgrounds.

Within an hour's drive from the City of Anaheim are Knott's Berry Farm in the adjacent City of Buena Park, the Los Alamitos Race Course, the renowned Spanish Mission of San Juan Capistrano, and the Art Colony at Laguna Beach with its annual art festival. Within two hours' drive are the numerous summer and winter resort areas in the San Bernardino and San Jacinto mountains. The Newport Harbor area, a few miles south of the City, provides anchorage facilities for over 5,000 private boats. Boat launching ramps, deep sea fishing, skin-diving, and other related water activities are readily accessible.

Other Anaheim facilities include a main public library and four branch libraries. Within the City, there are eight general hospitals with a capacity of 841 beds, four AM or FM radio stations, 32 banks and 14 savings and loan associations, and 80 churches of all major denominations.

Retail Sales

The table below presents the City's taxable retail sales for various years since 1975 in comparison to other cities in Orange County, Orange County and the State of California:

ANAHEIM, MAJOR ORANGE COUNTY CITIES, ORANGE COUNTY, CALIFORNIA
Taxable Retail Sales, All Outlets(1)
(000)

	1979	1978	1977	1976	1975
ANAHEIM	$ 1,526,416	$ 1,260,683	$ 1,086,585	$ 886,008	$ 766,615
Buena Park	522,520	436,426	383,468	338,440	299,196
Costa Mesa	675,306	815,022	698,038	575,742	476,960
Fullerton	562,669	500,784	445,159	371,480	299,552
Garden Grove	554,627	464,878	434,803	365,357	309,886
Huntington Beach	732,364	623,047	548,657	438,178	359,266
Orange	799,670	697,247	625,790	510,406	415,749
Santa Ana	1,325,754	1,163,460	1,008,058	837,445	684,956
Westminster	444,769	400,786	360,953	284,229	230,854
Major Cities	7,344,095	6,362,333	5,591,511	4,607,285	3,843,034
All Other	4,244,687	3,602,096	3,066,617	2,358,609	1,908,399
Orange County	11,588,782	9,964,429	8,658,128	6,965,894	5,751,433
California	$131,678,257	$113,467,724	$99,481,969	$83,822,020	$73,475,703

(1) Owing to changes in the sales tax base for retail goods, the years are not totally comparable between years, but the trend in relative magnitude of retail sales tax bases are exhibited.

SOURCE: California State Board of Equalization, *Trade Outlets and Taxable Retail Sales in California* for 1975, 1976, 1977, 1978 and 1979.

Following is the breakdown of 1979 sales tax permits in the City by type of outlet, and the percentage of each type's total taxable dollar transactions:

Type of Outlet	Permits	Per Cent of Transactions
Apparel Stores	113	2.0%
General Merchandise Stores	38	4.6
Drug Stores	28	1.1
Food Stores	155	4.9
Packaged Liquor Stores	55	1.0
Eating and Drinking Places	455	10.0
Home Furnishings and Appliances	165	3.7
Building Materials and Farm Implements	77	7.8
Auto Dealers and Auto Supplies	96	10.7
Service Stations	151	6.0
Other Retail Stores	462	7.3
All Other Outlets	4,260	40.9

SOURCE: Taxable Sales in California, 18th Annual Report, State Board of Equalization.

Education

The City is served by five elementary, two union high, and three unified school districts, and two community college districts. However, almost all of the City lies within eight districts: the Anaheim City, Magnolia, Savanna and Centralia Elementary School Districts, the Anaheim Union High School District, the Placentia Unified School District, the Orange Unified School District, and the North Orange County Community College District.

There are eleven institutions of higher learning in Orange County and an additional twelve in adjacent areas of southern Los Angeles County. Within Orange County are the University of California, Irvine; California State University, Fullerton; Chapman College; Southern California College; and public community colleges with grade 13 and 14 enrollments totalling nearly 120,000.

FINANCIAL INFORMATION

Certain Financial Information

The following unaudited summaries of certain Funds of the City have been prepared by the City of Anaheim Finance Department from audited financial statements.

CITY OF ANAHEIM
ALL GOVERNMENTAL FUND TYPES(1)
SUMMARY OF REVENUE AND TRANSFERS

Years Ended June 30,

	1975	1976	1977 (Thousands)	1978	1979
Property taxes	$ 6,644	$ 7,180	$ 7,793	$ 8,453	$ 5,187
Other taxes (including Sales and Use Taxes)	8,129	8,989	10,557	12,594	15,001
Licenses, fees and permits	1,716	2,432	2,889	3,938	2,931
Fines, forfeits and penalties	578	670	669	867	1,018
From other governmental agencies	8,311	11,538	14,256	26,286	23,544
Interest and rental	1,122	896	920	1,268	1,532
Charges for services	2,599	2,725	4,223	4,542	7,971
Other revenues	319	157	464	1,536	1,403
Revenue before transfer from other funds	29,418	34,587	41,771	59,484	58,587
Transfers from other funds	5,128	5,801	4,416	7,009	6,340
Total revenue and transfers	$34,546	$40,388	$46,187	$66,493	$64,927

SUMMARY OF EXPENDITURES

Years Ended June 30,

	1975	1976	1977 (Thousands)	1978	1979
General government	$ 3,385	$ 3,845	$ 4,490	$ 5,671	$ 8,564
Non departmental	2,289	3,661	4,960	6,357	5,254
Public safety	13,450	14,919	16,874	19,609	21,476
Public works	9,759	10,382	11,978	16,201	28,629
Parks and recreation	3,621	4,351	4,820	6,044	4,935
Library	1,308	2,126	1,792	1,766	1,667
Total operating expenditures	33,812	39,284	44,914	55,648	70,525
Redemption of serial bonds, general obligation	1,260	1,085	1,085	1,045	1,045
Interest expense general obligations	305	269	233	196	161
Total expenditures	$35,377	$40,638	$46,232	$56,889	$71,731

(1) Includes the General Fund, Special Revenue Funds, Debt Service Fund and Capital Project Funds. Excludes Enterprise and internal service funds.

Budgetary Process

The fiscal year of the City begins on the first day of July of each year and ends on the thirtieth day of June of the following year.

At such date as the City Manager determines, each board or commission and each department head must furnish to the City Manager an estimate of revenues and expenditures for such department, board or commission for the ensuing fiscal year, detailed in such manner as may be prescribed by the City Manager. In preparing the proposed budget, the City Manager reviews the estimates, holds conferences thereon with the respective department heads, boards or commissions as necessary, and may revise the estimates as he or she deems advisable.

At least sixty days prior to the beginning of each fiscal year, the City Manager submits to the City Council the proposed budget as prepared by him or her. After reviewing and making such revisions as it deems advisable, the City Council determines the time for the holding of a public hearing thereon and causes to be published a notice thereof not less than ten days prior to the hearing date. Copies of the proposed budget are available for inspection by the public in the office of the City Clerk at least ten days prior to the hearing.

At the conclusion of the public hearing, the City Council further considers the proposed budget and makes any revisions thereof that it deems advisable and on or before June 30 it adopts the budget with revisions, if any, by the affirmative vote of at least a majority of the total members of the Council.

From the effective date of the budget, the several amounts stated as proposed expenditures become appropriated to the several departments, offices and agencies for the objects and purposes named, provided that the City Manager may transfer funds from one object or purpose to another within the same department, office or agency. All appropriations lapse at the end of the fiscal year to the extent that they have not been expended or lawfully encumbered.

At any public meeting after the adoption of the budget, the City Council may amend or supplement the budget by motion adopted by the affirmative vote of at least a majority of the total members of the City Council.

Under the City charter, the City may not incur indebtedness evidenced by general obligation bonds which would in the aggregate exceed fifteen percent of the total assessed valuation, for purposes of City taxation, of all the real and personal property within the City, and no bonded indebtedness which shall constitute a general obligation of the City may be created unless authorized by the affirmative votes of two-thirds of the electors voting on such proposition at any election at which the question is submitted to the electors. At present the City has no authorized but unissued general obligation bonds, and future authorizations are precluded as a result of the passage of Article XIIIA of the California Constitution.

The City Council employs, at the beginning of each fiscal year, an independent certified public accountant who, at such time or times as specified by the City Council, at least annually, and at such other times as he or she shall determine, examines the books, records, inventories and reports of all officers and employees who receive, control, handle or disburse public funds and of all such other officers, employees or departments as the City Council may direct. As soon as practicable after the end of the fiscal year, a report is submitted by such accountant to the City Council and a copy of the financial statements as of the close of the fiscal year is published. Separate financial statements are prepared for the Electric System and the water system.

Assessed Valuation and Tax Collections

Taxes are levied for each fiscal year on taxable real and personal property which is situated in the City as of the preceding March 1. For assessment and collection purposes, property is classified either as "secured" or "unsecured" and is listed accordingly on separate parts of the assessment roll. The "secured roll" is that part of the assessment roll containing State-assessed public utilities property and property the taxes on which are a lien on real property sufficient, in the opinion of the County Assessor, to secure payment of the taxes. Other property is assessed on the "unsecured roll".

Property taxes on the secured roll are due in two installments, on November 1 and February 1 of the fiscal year. If unpaid, such taxes become delinquent on December 10 and April 10, respectively, and a 6% penalty attaches to any delinquent payment. In addition, property on the secured roll with respect to which taxes are delinquent is sold to the State on or about June 30 of the fiscal year. Such property may thereafter be redeemed by payment of the delinquent taxes and the delinquent penalty, plus a redemption penalty of 1% per month to the time of redemption. If taxes are unpaid for a period of five years or more, the property is deeded to the State and then is subject to sale by the County Tax Collector.

Property taxes on the unsecured roll are due as of the March 1 lien date and become delinquent, if unpaid, on August 31 of the fiscal year. A 6% penalty attaches to delinquent taxes on property of the unsecured roll, and an additional penalty of 1% per month begins to accrue beginning November 1 of the fiscal year. The taxing authority has four ways of collecting unsecured personal property taxes: (1) a civil action against the taxpayer; (2) filing a certificate in the office of the County Clerk specifying certain facts in order to obtain a judgment lien on certain property of the taxpayer; (3) filing a certificate of delinquency for record in the County Recorder's office, in order to obtain a lien on certain property of the taxpayer; and (4) seizure and sale of personal property, improvements or possessory interest belonging or assessed to the assessee.

Total assessed valuation for revenues purposes in the City increased from $54[illegible],374,168 to $1,308,557,841 at an average annual rate of approximately [illegible].0% from 1971-72 to 1980-81. Such assessed valuations include secured and unsecured properties assessed by the Orange County Assessor, and secured utility properties assessed by the State Board of Equalization. Such assessed valuations are before deduction of State-reimbursed homeowner's and business inventory exemptions but exclude veterans, religious, charitable, and other such nonrecoverable exemptions. Excluded also are the incremental assessed valuations within redevelopment project areas, the tax revenues from which were allocated to the Anaheim Redevelopment Agency in the years beginning with 1974-75.

The tax roll for 1980-81 indicates a Full Market Valuation of $5,234,231,364 for the City.

In addition to a 10-year record of assessed and estimated full market valuations, the table below shows the City tax levies, collections, and delinquency percentages for the last nine completed fiscal years.

CITY OF ANAHEIM

Assessed Valuation and Tax Collection Record

Fiscal Year Ended June 30	Estimated Full Market Valuation(1)	Assessed Valuation For Revenue Purposes(2)	Total City Tax Levy	Total Current Tax Levy Collections	Per Cent of Levy Uncollected	Population	Per Capita Estimated Full Market Valuation
1972	$ 2,166,388,000	$ 545,374,168	$5,418,580	$5,336,373	1.5%	180,000	$ 12,035
1973	2,423,495,000	608,099,032	6,049,488	5,900,915	2.5	186,200	13,016
1974	2,661,901,000	665,475,350	6,115,299	5,879,795	3.9	187,400	14,204
1975	2,919,524,000	729,881,000	6,642,416	6,359,885	4.3	191,800	15,222
1976	3,172,463,000	807,673,074	7,378,264	6,934,601	6.0	197,200	16,088
1977	3,590,239,000	914,230,624	7,751,993	7,482,161	3.5	200,100	17,942
1978	4,169,099,000	1,042,274,804	8,384,523	8,232,390	1.8	204,800	20,357
1979	4,352,207,000	1,088,051,689	5,359,430	4,952,832	7.6	208,500	20,874
1980	4,923,566,000	1,230,891,544	5,799,946	5,439,736	6.2	211,700	23,346
1981	5,234,231,364	1,308,557,841	6,674,640	N.A.	N.A.	217,800(3)	24,032(3)

(1) Estimated full market valuation is based on the Orange County Assessor's ratio of 25%, effective since 1961-62, for all property except public utilities property. Estimated full market valuation for public utilities property is based on the ratio used each year by the State Board of Equalization.

(2) Consists of gross assessed valuation, less redevelopment project area incremental assessed valuations, the taxes on which are payable to the Anaheim Redevelopment Agency, without deduction for homeowners and business inventory exemptions.

(3) Estimated.

SOURCE: City of Anaheim Annual Financial Reports and City Finance Director.

Summarized below is a ten-year history of property tax rates levied by the City and overlapping taxing agencies in a typical tax code area in Anaheim.

CITY OF ANAHEIM TYPICAL TAX CODE AREA

Property Tax Rate History

Fiscal Year Ended June 30	Basic County, City, School Levy	City	County of Orange	School Districts	Orange County Sanitation District	Orange County Flood Control	Metropolitan Water District	Other	Total Tax Rate Per $100 Assessed Valuation
1971	—	1.0500	1.7160	6.5633	.4256	.2505	.1700	.1365	10.3119
1972	—	1.0500	2.0688	6.5185	.4255	.2481	.1700	.2072	10.6881
1973	—	1.0500	2.1950	6.6102	.4254	.2395	.1500	.0925	10.7626
1974	—	1.0500	1.7344	6.3384	.4206	.2332	.1400	.2742	10.1908
1975	—	1.0500	1.6582	6.1420	.3825	.2222	.1400	.2585	9.8534
1976	—	1.0500	1.6875	6.1294	.3793	.2169	.1300	.1865	9.7796
1977	—	.9500	1.4854	5.7992	.3467	.1872	.1200	.2827	9.1712
1978	—	.8800	1.3761	5.8589	.2988	.1888	.2000	.2518	9.0544
1979	4.000	.1470	.0032	.5312	.0215	.0171	.1000	—	4.8200
1980	4.000	.0950	.0028	.4640	.0240	.0146	.1000	—	4.7004

SOURCE: County *Tax Rates* (various years). Auditor-Controller, County of Orange.

Direct and Overlapping Debt

Although the 1980 Bonds will be payable from Gross Revenues of the Electric System, the direct and overlapping bonded debt of the City as of October 1, 1980 is shown below for informative purposes.

CITY OF ANAHEIM

STATEMENT OF DIRECT AND OVERLAPPING DEBT*

As of October 1, 1980

1980-81 Assessed Valuation: $1,308,557,841 (after deducting redevelopment tax allocation increment)

DIRECT AND OVERLAPPING BONDED DEBT:

	% Applicable	Debt 10/1/80
Orange County	10.525%	$ 342,588(1)
Orange County Building Authorities	10.525	2,047,401
Orange County Flood Control	10.525	1,843,980
Metropolitan Water District	2.000	10,094,380
County Sanitation Dist. #2 (Various Issues)	34.251-34.270	1,082,400
County Sanitation Dist. #3	9.309	451,393
North Orange County Community College District	50.537	1,440,304
Fullerton Comm. College and Union High School Dists.	0.263	12,055
Anaheim Union High School Dist. (Various Issues)	62.847-62.869	16,244,082
Orange Unified School District (Various Issues)	17.699-18.373	3,385,236
Placentia Unified School District (Various Issues)	29.066-30.160	6,752,635
Anaheim School District (Various Issues)	99.493-99.498	1,527,293
Centralia School District (Various Issues)	14.419-14.606	177,618
Magnolia School District	65.675	13,135
Savanna School District	46.583	261,330
Other School Districts	Various	61,313
City of Anaheim	100.	2,515,000
City of Anaheim Building Authorities	100.	94,460,000(2)
Municipal Water Dist. of Orange Co. Water Facilities Corporation	11.876	9,429,544
Other Special Districts	Various	36,200
TOTAL GROSS DIRECT AND OVERLAPPING BONDED DEBT		$152,177,887(3)
Less: Water and electric bonds (100% self-supporting)		1,410,421
Convention Center bonds (Series A, B, C and D 100% s-s)		50,405,000
Water Facilities Corporation (100% s-s)		9,429,544
Stadium Inc. (100% s-s)		44,055,000
TOTAL NET DIRECT AND OVERLAPPING BONDED DEBT		$ 46,877,922

(1) Excludes share of Orange County lease-purchase obligations.
(2) Includes approximately $24,340,000 Anaheim Community Center Authority Bonds to be sold.
(3) Excludes revenue and tax allocation bonds.

Ratios to Assessed Valuation:

Gross Direct Debt ($96,975,000)	**7.41%**	**Total Gross Debt**	**11.63%**
Net Direct Debt ($1,104,579)	**0.08%**	**Total Net Debt**	**3.58%**

SHARE OF AUTHORIZED AND UNSOLD BONDS:

Metropolitan Water District	$7,300,000
Placentia Unified School District	$4,224,743
Centralia School District	$ 249,449

STATE SCHOOL BUILDING AID REPAYABLE AS OF 6/30/80: $31,356,346

* SOURCE: City of Anaheim Finance Department and California Municipal Statistics Inc.

Constitutional Amendments Affecting City Revenues

On June 6, 1978, California voters approved Proposition 13, a statewide initiative relating to the taxation of real property which added Article XIIIA to the California Constitution. Among other things, the Proposition: (a) Limits ad valorem property taxes of all real property to one percent (1%) of the full cash value of the property; (b) Exempts existing voter approved bonded indebtedness from the 1% limitation; (c) Defines "full cash value" as the Assessor's appraised value of real property as of March 1, 1975, adjusted by changes in the Consumer Price Index — not to exceed 2% per year; (d) Permits establishment of a new "full cash value" when there is new construction or a change in ownership; (e) Permits the reassessment, up to the March 1, 1975 value, of property which was not current on the 1975-76 assessment roll; (f) Requires counties to collect 1% property tax and to "apportion it according to law to the districts within the counties"; (g) Prohibits new ad valorem taxes on real property, or sales taxes, or transaction taxes, on the sales of real property; (h) Permits the imposition of special taxes by local agencies; and (i) Requires a two-thirds (⅔) vote of all members of both houses of the Legislature for any changes in State taxes which would result in increased revenues.

Various legislative measures have been adopted by the California legislature since the passage of Proposition 13 to reduce its impact on local governments. The net effect of Proposition 13 and such measures in the fiscal year ended June 30, 1979 was a reduction of City budget resources of approximately $3.0 million from the prior year level. The City has taken various steps to restrict spending and adjust fees and service charges in light of Proposition 13. It is unable to predict whether state assistance will continue at recent levels or whether further budgetary and other measures will be required in the future to offset the effects of the Proposition.

A special election was held on November 6, 1979, at which time the voters of the State of California approved the Initiative Constitutional Amendment — Limitation of Government Appropriations ("Proposition 4") which added Article XIIIB to the California Constitution. The details are complex and will require clarification from subsequent legislation or judicial decisions. The City cannot predict whether the Amendment will, if challenged, be upheld, in whole or in part, by the courts.

Proposition 4 went into effect on July 1, 1980 and provides that state and local government appropriations from certain revenue sources each year may not exceed the appropriations limit related to such revenue sources set for the fiscal year 1978-79, with certain adjustments made for changes in the cost of living and population. Any surplus revenues will be required to be returned to the taxpayers through downward revision of tax rates and fee schedules during the subsequent two fiscal years. The measure also contains provisions relating to emergency situations, revision of the appropriations limit by a majority vote of the people, reorganizations of governments, savings by government, nonimpairment of bonds, allocation of funding of state-mandated programs, and various exemptions.

The City is subject to Proposition 4. Based on certain assumptions (which will require clarification as discussed above), the City believes that the limitations imposed on it by Proposition 4 will have the effect of reducing the funds expected (in the absence of Proposition 4) to be available for the payment of various anticipated City expenditures.

Largest Taxpayers

The nine largest taxpayers in Anaheim and their 1979-80 assessed valuations are as follows:

CITY OF ANAHEIM
Major Taxpayers, 1979-80

Taxpayer	Assessed Valuations for Revenue Purposes	Number of Employees
Disneyland	$ 34,768,680	6,000
Rockwell International Corporation	32,964,640	8,000
Disneyland Hotel	15,061,040	1,400
Delco-Remy Division, General Motors Corporation	8,486,370	475
Northrop Electro-Mechanical Division, Northrop Corporation	6,928,555	1,800
Kwikset Division, Emhart Industries, Inc.	6,674,685	1,800
California Computer Products, Inc.	6,109,270	800
Interstate Electronics Corp., Division of A-T-O, Inc.	3,560,260	1,700
Monsanto Plastic and Resins Company — Packaging Division	3,213,520	350
	$117,767,020	22,325

SOURCE: Orange County Assessors Office and "Orange County Business", February/March, 1980.

Pension

City personnel belong to the State Public Employees Retirement System (P.E.R.S.). As of June 30, 1976, P.E.R.S. had separate contracts with the State of California and 944 local public agencies, including coverage for 1,109 school and community college districts. Membership includes safety, state industrial, and miscellaneous groups. Each group has somewhat differing programs and amounts of actuarial liabilities. For the Public Employees' Retirement Fund as a whole, net assets available for benefits on June 30, 1976, according to the annual audit were $7,858,768,931, while the unfunded obligation was $6,753,964,123. The latter is the amount by which the excess of the present value of total projected benefits over the sum of the present values of future employer normal costs and future member contributions exceeds the amount of available net assets at carrying value. Based on the latest actuarial valuation, the City's unfunded prior service cost relating to the City's participation in P.E.R.S. was $976,000, which is being funded over 25 years ending June 30, 2000.

Contributions to P.E.R.S. of 7% of the miscellaneous employees' earnings, and 9% of the public safety employees' earnings, are accomplished through automatic paycheck deductions. The City's contribution rate is determined by periodic actuarial valuations based on the benefit formula and the number of employees and their respective salary schedules. For 1979-80, the City's contribution rate was 14.126% for miscellaneous employees and 27.905% for public safety employees. The rates for 1980-81 are 14.498% and 27.905% for miscellaneous and public safety employees respectively. City contributions totaled $5,875,000 for 1978-79.

Labor Relations

City employees are represented by various unions, and labor relations have been generally amicable in that there have been no major strikes, work stoppages, or other incidents. Currently, 68.3% of all city employees are represented by unions, including the Anaheim Municipal Employees Association; the Anaheim Police Association; the Anaheim Fire Association; the International Brotherhood of Electrical Workers, Local 47 (IBEW) (utility department employees); the Hospital and Service Employees Union, Local 399 and the General Truck Drivers Union, Local 952. The preceding are designated representatives under the Meyer-Milias-Brown Act (Section 3500 *et seq.* of the Government Code of California) and are covered by memoranda of understanding for periods expiring October 9, 1980, except for the memoranda with the latter two unions, which expire February 6, 1983. Negotiations are currently being conducted to renew memoranda of understanding which expire on October 9, 1980. There are no other organized employee groups.

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PROPOSED FORM OF LEGAL OPINION

.................., 1980

We have examined certified copies of the proceedings taken for the issuance of $84,000,000 electric revenue bonds (the "1980 Bonds") of the City of Anaheim, California, and the sale of the 1980 Bonds to the underwriters thereof. We have also examined executed 1980 Bond No. 1. The 1980 Bonds are part of a total issue of $150,000,000 authorized at an election held March 4, 1975, are issued pursuant to Section 1210 of the City Charter, City Ordinance No. 2980, as amended, and Resolution No. 80R-457 (the "Resolution") of the City Council of said City, are designated "Electric Revenue Bonds, Issue of 1980", consist of 14,600 bonds, numbered 1 to 14,600 inclusive, in the denomination of $5,000 each, dated October 1, 1980, bear interest payable semiannually thereafter at the rate of 8% per annum and mature in consecutive numerical order on October 1 in each of the years and in the amounts, as follows:

Year	Principal Amount	Year	Principal Amount
1984	$1,250,000	1992	$2,325,000
1985	1,375,000	1993	2,525,000
1986	1,450,000	1994	2,725,000
1987	1,600,000	1995	2,925,000
1988	1,700,000	1996	3,175,000
1989	1,850,000	1997	3,425,000
1990	2,000,000	2001	16,650,000
1991	2,150,000	2007	36,875,000

The 1980 Bonds maturing on or after October 1, 1991 are subject to call and redemption prior to maturity on the dates, at the prices and in the manner set forth in the Resolution.

Our services as bond counsel to the City were limited to an examination of the transcript of legal proceedings referred to above, to a review of the description of the issue, statements of law and legal conclusions set forth in the Official Statement for this issue under the captions "Security for and Sources of Payment for the Bonds" and "Description of the 1980 Bonds", and to the rendering of the opinions set forth below.

From such examination, we are of the opinion that:

1. The proceedings have been taken in accordance with the laws and Constitution of the State of California and the Charter and Ordinance No. 2980, as amended, of said City, and that the 1980 Bonds, having been issued in duly authorized form and executed by the proper officials and delivered to and paid for by said underwriters, constitute the legally valid and binding obligations of said City, payable from the gross revenues of the Electric System of the City as set forth in the Resolution and not out of any other fund or moneys of said City, but said provision for such payment out of said fund does not preclude payment from certain other sources mentioned in the Resolution.

2. The 1980 Bonds, and any parity bonds (as defined in the Resolution), are equally secured by a valid pledge, charge and lien upon said gross revenues, as provided in the Resolution.

3. The Resolution has been duly adopted, and the agreements and covenants contained in the Resolution are authorized by law and are legally valid and binding.

4. The form and execution of 1980 Bond No. 1 are regular and proper.

The agreements, covenants, and obligations described in the foregoing paragraphs, however, may be limited by bankruptcy, insolvency, or other laws affecting the enforcement of creditors' rights.

We are further of the opinion that interest on the 1980 Bonds is exempt from income taxes of the United States of America under present federal income tax laws and such interest is also exempt from personal income taxes of the State of California under present state income tax laws.

We are further of the opinion that the amount of original issue discount, if any, in the selling price of the 1980 Bonds (which original issue discount with respect to each maturity of the 1980 Bonds equals, at a minimum, the lesser of (i) the difference between the principal amount of such 1980 Bonds and the price paid to the underwriters by the original purchasers of a substantial portion of the 1980 Bonds of such maturity, and (ii) the difference between the principal amount of such 1980 Bonds and the price paid by the underwriters, calculated in each case without regard to accrued interest) represents interest which is exempt from federal income taxation to the same extent expressed in the preceding paragraph; provided, however, that in the case of a sale or exchange of such 1980 Bonds or the redemption of such 1980 Bonds prior to maturity such original issue discount is apportioned among such original purchaser of such 1980 Bonds and subsequent holders, and each respective holder is entitled to treat as exempt from federal income taxation, at a minimum, that portion of his gain, if any, which does not exceed the amount of such original issue discount with respect to such 1980 Bonds multiplied by a fraction the numerator of which is the number of days (computed on an actual calendar day basis) such 1980 Bonds were owned by him and the denominator of which is the total number of days from the date of issuance of such 1980 Bonds to the date of maturity of such 1980 Bonds.

Respectfully submitted,

O'MELVENY & MYERS