SOUTHERN CALIFORNIA EDISON COMPANY

PREPARED TESTIMONY

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EXHIBITS

RESULTS OF OPERATIONS - EXHIBIT NO. (SCE-2)

8103110698

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Mr. Jack K. Horton

(General Considerations)

Q. Please state your name and address for the record.

A. My name is Jack K. Horton and my business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your occupation?

A. I am Chairman of the Board of Directors and Chief Executive Officer of the Southern California Edison Company.

Q. For the record, please briefly summarize your qualifications.

A. I am a graduate of Stanford University in 1936 and Oakland College of Law in 1940.

From 1943 to 1944, I was employed by Standard Oil Company of California as an attorney.

From 1944 to 1951, I was the Secretary and Legal Counsel of Pacific Public Service Company and its subsidiaries. The subsidiaries included two pipeline companies, a gas and electric utility company, and a company engaged in the exploration and production of natural gas. I was elected Executive Vice President for this group of companies in March 1951 and President in March 1952.

From May 1954 to February 1959, I was Vice President of Pacific Gas and Electric Company.

In 1957, I was elected President of Alberta and Southern Gas Company and Alberta Natural Gas Company, which were Canadian subsidiaries of Pacific Gas and Electric Company.

On February 1, 1959, I was elected President of the Southern

California Edison Company. In April 1965, I was elected President and Chief Executive Officer and in April 1968, I was elected to my present position.

Q. Mr. Horton, why is Edison seeking a general rate increase at this time?

A. Edison's financial performance in 1980 and 1981 is expected to deteriorate to below acceptable levels, with the earned rate of return and return on common equity projected to be considerably below the levels authorized by the Commission in Decision No. 89711. This deterioration is forecast to be caused by rising imbedded debt and preferred stock costs, cost increases stemming from a general inflation rate in excess of 8%, additional costs imposed by legislative and regulatory requirements without adding to output, and additions to rate base. Substantial rate relief is an absolute necessity in 1981 if a decrease in Edison's financial integrity, credit standing, and ability to continue to attract capital is to be avoided.

The Company appreciates the progress made by the Commission in its 1979 decision. The return on common equity was increased to a more appropriate level, rate relief was effective for the full test year, and the regulatory time was reduced to 14 months from filing the application to decision. However, subsequent to that decision, the inflation rate rose, financial costs increased, additional regulatory and legislative requirements were imposed, and the rate base increased substantially (on a projected basis) with the addition of San Onofre Unit No. 2. With the advent of the Three Mile Island incident, world fuel oil and natural gas problems, and the deterioration of general economic conditions, investors perceive electric utilities as more risky and now require a higher return in order to be attracted. As a result, the cost of debt and preferred stock have risen since the Commission authorized Edison a 13.49% return on common equity for 1979, and the Company's common stock price remains well below book value, indicating that the authorized return on common equity is inadequate.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the general framework upon which Edison's request for rate relief is based. More specifically, I intend to discuss:

1. The reasons for the expected earnings decline.
2. What Edison has done to reduce financial and operating costs, increase productivity, and optimize the funds required to provide necessary production, transmission, and distribution facilities.
3. The need for timely and adequate rate relief.
4. The need for a rate of return allowance to compensate for the 1982 earnings erosion resulting from the expected increases in imbedded debt and preferred stock costs, in operating and maintenance costs exclusive of fuel and income taxes, and in rate base resulting primarily from the addition of San Onofre Unit No. 2.
5. The need for a balancing account to compensate for that portion of the erosion in rate of return attributable to the addition of San Onofre Unit No. 2 to rate base since its impact on earnings during 1981 is not reflected in the request for rate relief in this filing.

Q. What is the primary financial cause of earnings erosion?

A. Financings are expected to cause considerable earnings erosion during the 1979-1983 period. This is primarily because a substantial amount of debt and preferred stock are forecast to be sold at well in excess of imbedded costs during the period.

Edison's cash needs attributable to its construction program and refundings during the 1979-1983 period are expected to total $3.4 billion, an increase of 42% over the cash requirement during the 1974-1978 period. Even with the rate relief requested in this application and sufficient 1983 rate relief to provide about a 15% return on common equity, Edison's dependence on financial markets for cash funds would be at about the 70% level, or $2.4 billion during the 1979-1983 period. To emphasize the magnitude of this financing need, the $2.4 billion financing requirement is 71% greater than the $1.4 billion requirement during the 1974-1978 period.

In addition, Edison cannot maintain its financial integrity, credit standing, and ability to attract capital if its dependence on external sources for cash funds remains at about 70% in the long run. However, for the 1979-1983 period, such a level may be the minimum acceptable. This is because appropriate rate relief in 1981, 1982, and 1983 should sharply reverse the serious level of 95% dependence from external sources in 1979 and 1980. This further emphasizes the importance of sufficient and timely rate relief with adequate provision for attrition during the 1981-1983 period.

The cost of debt and preferred stock financings in 1982, even with sufficient and timely rate relief with adequate provision for attrition, will be much higher than in the past. Debt and preferred stock financing costs are expected to average about 9.75% and 9.50% during the 1979-1983 period. These costs, along with the amount of financings required, will increase imbedded costs to about 8.03% for debt and 7.80% for preferred stock in 1981. The imbedded cost increases alone in 1982 will result in a 37 basis point drop in the return in common equity in that year.

Q. Has Edison's return on common equity been adequate?

A. Edison's price/book ratio has remained well below one for the entire period since 1972. This price performance indicates that investors do not believe Edison's return on common equity has been adequate.

Q. What did these inadquate earnings cost Edison common stockholders?

A. The 19 million shares of common stock which were sold below book value during the 1974-1978 period reduced existing common shareholders' book investment by about 10.1% per share during the period. This also means that all prospective earnings per share have been reduced by the same 10.1% because earnings per share are derived from book investment per share.

Q. If Edison had been able to sell shares at book value during the 1974-1978 period, how many fewer shares would have been sold?

A. Edison would have sold 6.4 million fewer shares during the 1974-1978 period to raise the same amount of common equity capital it actually raised by issuing 19.1 million shares, a potential 34% reduction. Moreover, If Edison had been able to sell 6.4 million fewer shares, its dependence on capital markets for funds to build plant would have been substantially reduced. For example, at the current annual dividend rate of $2.72 per share, the Company has to pay about $17 million more annually in dividends than it would have if common stock had been sold at book value since 1973. Therefore, not only has the issuance of common stock been below book value, thereby eroding earnings per share and shareholder worth, but it also has placed additional pressure on Edison's financing needs because of the increased dividend requirement.

Q. How do operation and maintenance costs contribute to earnings erosion?

A. The general rate of inflation is expected to exceed 8% during the 1979-1983 period compared to an annual trend rate of about 7% during the 1974-1978 period. While Edison might compensate for some of this expected inflation through productivity increases, it would not be reasonable to assume inflationary increases could be offset in this way, especially because legislative and regulatory requirements continue to increase costs without increasing output.

Q. How do rate base additions reduce the rate of return on investment and erode earnings?

A. San Onofre Unit No. 2, for example, is expected to be added to rate base in 1981. At that time, the financing costs for San Onofre Unit No. 2 will no longer be capitalized through AFDC, and earnings therefore will decline. Other expenses associated with plant, such as ad volorem taxes, will be expensed instead of capitalized, and depreciation expense will begin to be charged to utility operations. These changes also will reduce earnings. In addition, the rate base will be increased out of proportion to the increase in system capacity. Without a substantial increase in revenues to cover the increased expenses associated with San Onofre Unit No. 2 and to provide the authorized rate of return on the investment, the earned rate of return will decline. Because San Onofre Unit No. 2 represents a 1981 investment of about $1.2 billion, the impact would be substantial unless some provision is made for its impact. It should be noted that the fuel expense associated with San Onofre Unit No. 2 will be less than that for fuel oil. As San Onofre Unit No. 2 increases its production of electricity, fuel oil costs will be displaced, resulting in a lower ECAC billing factor. This benefit, which will be passed on to customers in a very short time, should largely offset the revenue increase required for the addition of San Onofre Unit No. 2 to rate base.

Q. What has Edison done to reduce costs and increase productivity and managerial effectiveness?

A. Edison has implemented many management processes and controls to reduce costs and increase productivity and managerial effectiveness. These require a high level of interest and involvement on the part of Edison's senior management.

The Management Committee, which I chair, is at the center of these processes and controls. It consists of the Chairman of the Board, President, Executive Vice President, and the two Senior Vice Presidents. The Committee meets weekly to review corporate plans, budgets, and provide corporate policy decisions. Some of the key plans reviewed by the Management Committee include Executive Plans, Program Plans, and Replaceability and Executive Development Plans.

Executive Plans are prepared annually by corporate vice presidents to determine corporate problems and opportunities, develop objectives, and provide plans of action.

Program Plans are prepared for specific areas by the organizations involved. Recent program plans have been prepared with regard to research and development, the environment, fuel supply, financial needs, and data processing.

Replaceability and Executive Development Plans are prepared by departments each year to deal with the availability of managers ready to replace department heads and officers. It also deals with the development and cross training needs of those managers who have high potential but who are not yet ready.

The Management Committee also reviews budgets that are prepared by each organization annually and at mid-year for those that have material deviations from budget. The process used by Edison to eliminate unnecessary expenses and to cause plans for increased expenses to be carefully reviewed and justified is referred to as the modified zero based budgeting process. In addition, the expanded use of internal operational and financial auditing provides control and incentive for managers to be efficient and cost conscious.

The committee process is also used to promote cost reductions and improve productivity as a joint process. Some of the key committees in this regard include the Corporate Budget Committee, the Plant Expenditure Review Committee, the Productivity and Management Effectiveness Committee, and the Peak Demand and System Capacity Factor Management Committee.

The Corporate Budget Committee reports to the Chairman of the Board and provides staff support to the Board of Directors' Budget Committee. The chairman of this committee is a Senior Vice President. The purpose of the committee is to review all budgets and control costs.

The Plant Expenditure Review Committee reports to the Chairman of the Corporate Budget Committee and is chaired by a Senior Vice President. Its purpose is to review plant expenditures in order to minimize the level of plant investment required to provide reliable service.

The Productivity and Management Effectiveness Committee reports to the Chairman of the Board and is chaired by the Corporate President. Its purpose is to direct productivity and management effectiveness programs, to evaluate policies and practices related to productivity, and to measure corporate productivity with regard to capital, labor, and fuel. The efforts are not only directed at the most efficient mix of inputs (e.g., capital, labor, and fuel) for a given output (i.e., kWh sales) but also directed at improving the output for a given set of inputs. For example, one program is directed at reducing line losses on the subtransmission and distribution system with a goal of reducing line losses in 1981 by 50 million kWh.

The Peak Demand and System Capacity Factor Management Committee reports to the Corporate President and is chaired by a Senior Vice President. Its purpose is to formulate strategies and policies to modify peak demand and improve the system capacity factor.

Q. How have you determined whether you have been successful at controlling costs and improving productivity and managerial effectiveness?

A. Several measures can be used. Edison's labor productivity performance has been excellent as indicated by the following measures: The U.S. Bureau of Labor Statistics uses a measure that is often quoted in the news media - output per manhour. Edison increased its output per manhour on an annual trend rate basis of 3.3% compared to a 1.8% average for U.S. Gas and Electric Utilities and 1.9% average for U.S. Non-farm Business during the 1974-1978 period. Since Edison's output is based on kWh sales, it should be noted that Table 9 of Exhibit No. (SCE-1)_____ shows that kWh sales during the same period grew at about the same annual trend rate. This indicates that Edison's manhours were held constant for about five years while kWh sales increased.

Table 9 of Exhibit No. (SCE-1)_____ shows that the number of Edison's employees <u>declined</u> at an annual trend rate of about 0.4% while the number of employees for the 20 largest electric utilities <u>increased</u> at an annual trend rate of 2.3% during the 1974-1978 period.

Chart 5A of Exhibit No. (SCE-1)_____ shows that Edison's employees per 10,000 customers declined from about 51 in 1974 to about 46 in 1978 while the same ratio for the 20 largest group remained at about 76 during the period. Customer growth was obviously not the cause because Edison's customers increased at an annual trend rate of 2.6% for the period compared to 2.4% for the 20 largest group during the same period. Table 9 of Exhibit No. (SCE-1)_____ shows these customer data.

While a 2.6% annual trend rate in customers does not seem large, this amounted to about 348,000 customers from 1973 through 1978, which is about half the number of San Diego Gas & Electric's customers. Edison reduced the average number of its employees by 235 during that same period.

Edison's financial costs have also been kept under control. Table 11 of Exhibit No. (SCE-1)_____ shows that Edison's average cost of debt and preferred stock are below those for the 20 largest group. In addition, Edison has maintained its bond and preferred stock ratings, even with depressed earnings. This has been accomplished by reducing the debt ratio as imbedded costs have risen, maintaining open and frequent contact with rating agencies, and constraining construction expenditures to manageable levels. Tables 5 and 6 of Exhibit No. (SCE-1)_____ show that double-A rated bond and preferred stock yields are lower than those for lesser rated securities.

Other measures show Edison has been effective in controlling plant investment. Table 8 of Exhibit No. (SCE-1)_____ shows that Edison has been able to reduce its forecasted kW demand and kWh sales during the 1979-1983 period as a result of its conservation and load management efforts. This has allowed Edison to reduce its total construction expenditures from $5.0 billion to $2.9 billion during the 1979-1983 period. as shown on Table 8. This has been achieved despite an annual trend rate of 10.6% in construction costs during the 1974-1978 period and forecasted construction cost increases of 10% in 1979, 9% in 1980 and 1981, and 8% in 1982 and 1983.

Another measure of Edison's effectiveness in controlling plant investment is shown on Table 9 of Exhibit No. (SCE-1)_____. Edison's net electric plant increased at an annual trend rate of 8.9% while the 20 largest group's net electric plant increased at an annual trend rate of 12.0%. Chart 5B of Exhibit No. (SCE-1)_____ further shows that Edison's plant investment per customer was comparable to that of the 20 largest group in 1968, but by 1978, the investment per customer was substantially different, with Edison's investment being much less (about $2,200 per customer for Edison compared to about $3,600 per customer for the 20 largest group).

Q. How has Edison used research and development?

A. Edison has actively moved into research and development projects to find new sources of energy, since conventional sources are in short supply, and to maintain and improve the environment. I am quite proud of Edison's record in this regard.

Q. What are some of the research and development programs undertaken by Edison to find new sources of energy?

A. Edison is participating in the development of a 10 megawatt solar plant, a 3 megawatt wind turbine, and two geothermal plants of about 9 megawatts. In addition, synthetic fuels are being researched. A 90-100 megawatt coal gasification plant at Cool Water is planned, a full-scale methanol test at Ellwood is under way, and shale oil testing at Highgrove has been completed. While this is not a complete list, I believe it is representative.

Q. What are some of the environmental projects being undertaken?

A. Edison has embarked on several programs. Some of these programs include:

1. A study of Atmospheric Properties to determine the effects of relevant pollutants.
2. San Onofre Marine Studies to determine ecosystem effects on Units 1, 2, and 3 and methods to mitigate adverse long-term effects.
3. A Hazardous Waste and Toxic Substances Program to deal with potential biological and human health problems.

4. A NOx Flue Gas Clean-up Program to determine NOx removal performance of selective catalytic reduction (SCR) compatibility of SCR units with existing generating stations and determine design criteria, cost, and schedule estimates for commercial operation (SOHIO project).

5. A NOx Combustion Control program to fully evaluate Low NOx Burners (LNB). The LNB Project at Highgrove demonstrated that such technology could reduce NOx.

6. A Sulfates, Particulates, and Trace Elements Program to measure effects at Mohave and Four Corners, measure effects of oil-fired emissions at Ormond Beach, and test a 10 MW oil-fired stack gas scrubber for reductions of SO_2.

Q. Does that complete your comments with regard to Edison's cost control, productivity, and managerial effectiveness programs?

A. Yes, it does. However, Edison cannot stem financial deterioration, no matter how effective its management performs, without substantial rate relief.

Q. What level of rate relief do you believe is necessary?

A. Edison requires a 10.78% rate of return and at least a 15.00% return on common equity to be earned in 1981. Rate relief must be sufficient in 1981 to allow these returns to be achieved. A provision for the impact of San Onofre Unit No. 2 being placed in rate base on July 1, 1981, and its negative impact on earnings in 1981 and 1982 should also be made to reduce the otherwise substantial earnings erosion. While Edison has separated the expenses and associated investment of San Onofre Unit No. 2 from this filing by placing those costs in a balancing account to be activated when the unit goes into operation, the rate relief requested in this filing will be sufficient only if another procedure to compensate Edison for the negative impacts resulting from the addition of the unit to rate base is approved. The balancing account method will benefit the consumer by enabling deferral of the revenue increase associated with San Onofre Unit No. 2 until the time that the plant actually goes into operation. As a result it reduces the amount of the request for a general rate increase which will be in effect for the full test year of 1981.

Finally, Edison needs an attrition allowance for 1982 to compensate for the 15 basis point increase in imbedded debt and preferred stock costs and the impact of an 8% inflation rate on operating and maintenance expenses, exclusive of fuel and income tax expenses.

Q. Why does Edison require a return on common equity of at least 15%?

A. Edison requires this level of return on common equity in order to meet the Hope and Bluefield Supreme Court tests that a company's return should be sufficient for it to maintain its financial integrity, credit standing and ability to continue to attract capital. In my judgment, this can be done only if Edison's return is commensurate with its cost of capital. I believe that Edison's common stock costs are in excess of 15%, with 15% being the minimum of the reasonable range. I believe Edison requires a return on common equity in excess of 15% in order to:

1. Increase Edison's common stock price to book value over a reasonable period of time.
2. Reflect the earnings/price ratio cost of common equity.
3. Reduce its dependence on financial markets for cash funds to an acceptable level.
4. Permit dividend increases at a rate that will meet investors' long-run inflationary expectations by providing sufficient cash earnings to cover dividends.
5. Maintain the risk premium investors require over bond yields without having the common stock price drop.
6. Maintain the interest coverage required to maintain bond

ratings as imbedded costs rise.

7. Compensate for Edison's increased risk level.

Q. What has caused Edison's risk level to rise?

A. While investors' perceptions may not be known fully by me, the price performance of Edison's common stock indicates that the return on common equity must be increased to compensate for the increased risk. Some of the risks which investors may believe have changed the attractiveness of Edison as an investment include:

1. The fear of investment loss has become an important consideration for utility investors. Since the Three Mile Island incident and the uncertain environment brought on by legislative and regulatory bodies, investors are less certain.
2. Plant siting problems cause longer lead times, more concern about final approval, and a greater CWIP financing burden. Diablo Canyon delays concern investors when they discuss Edison's San Onofre Units 2 and 3.
3. Environmental concerns dominate other issues, place standards and requirements in a state of flux, force investment before ability to meet standards and requirements is determined, and increase costs while impairing output.
4. Fuel availability and cost recovery are less certain.
5. Cash flows are less stable, especially with regard to ECAC, than before the oil embargo.
6. The impact of inflation on earnings, especially on regulated, capital-intensive utilities such as Edison has increased.
7. Demand forecasting is less certain as price increases, rate designs change, and the impact of programs are not reflected in historical data.
8. Energy policies at the state and federal level are sometimes inconsistent.

9. The uncertainty pertaining to plant investment resulting from technological change and the need to invest in new technology has increased.

10. The likelihood of Commission disallowances because of consumer advocacy and pressures to hold rates down have been perceived to have increased.

This list is by no means exhaustive, but I believe it does represent some of our investors' major concerns.

Q. Is it your view that these risks were not adequately recognized by the Commission in its 13.49% return on common equity allowance in Decision No. 89711 for test year 1979?

A. The performance of Edison's common stock since that decision for test year 1979 indicates that investors do not believe that the return on common equity allowance was adequate. Therefore, it is my belief that the authorized return on common equity of 13.49% did not fully recognize the risks perceived by investors.

Q. Mr. Horton, would you please summarize your testimony?

A. Edison is faced with accelerated inflation, increasing governmental requirements which add to the cost of doing business without increasing output, and the commitment to plant investments that, despite scaling down projected growth rates, are greater than at any time in its history. In order to avoid financial deterioration, Edison's management has minimized cost increases, increased productivity and managerial effectiveness, and constrained plant investment through budgeting review and peak demand and capacity factor programs. Despite Edison's substantial achievements with regard to cost control and increased productivity, Edison faces financial disaster unless substantial rate relief is approved. At least a 15% return on common equity is required to be earned in 1981. In addition, rate relief is required to compensate for the substantial attrition expected in 1982 as a result of continued escalation in the cost of service beyond management's control. Edison requires the rate relief requested in this Application in order for it to earn a return on common equity commensurate with its cost of capital and to maintain its financial integrity, credit standing and ability to continue to attract capital.

Q. Does this complete your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of H. Fred Christie

Exhibit No. (SCE-1)_____

(Financial Characteristics, Cost of Money and Required Return)

Q. Please state your name and business address for the record.

A. My name is H. Fred Christie, and my business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with Southern California Edison Company?

A. I am Senior Vice President.

Q. Please refer to Exhibit No. (SCE-3)_____ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of H. Fred Christie", does that portion of the exhibit accurately set forth your background, training, and experience?

A. Yes, it does.

Q. Are you testifying with respect to Exhibit No. (SCE-1)_____ entitled "Financial Characteristics, Cost of Capital, and Required Rate of Return"?

A. Yes.

Q. Was this exhibit prepared by you or under your supervision?

A. Yes.

Q. What is the purpose of your testimony and Exhibit No. (SCE-1)_____?

A. The purpose of my testimony is to demonstrate that:

1. The Company's cash needs from financial markets are larger now than in the past.
2. The Company's cost of debt and preferred stock financings will continue to be much greater than its imbedded cost of debt and preferred stock.
3. The Company has done much to reduce its cash need from

investors and to reduce the level of its debt and preferred stock costs.

4. The Company's control of imbedded debt and preferred stock costs, employment, kWh sales growth, and electric plant investment has been better than that of comparable electric utilities.

5. The Company needs a rate of return adjustment (attrition allowance) and a balancing account for the addition of San Onofre Unit No. 2 to compensate for the expected decline in earnings in 1982 since the Commission has indicated filings should not be made more than every other year.

6. The Company's required return on common equity is greater than that authorized in CPUC Decision No. 89711 for 1979. Specifically, the Company needs at least a 15% return on common equity and a 10.78% rate of return authorized and earned in 1981 for its returns to be commensurate with its cost of capital.

Q. How large are Edison's cash needs from financial markets?

A. Table 1 of Exhibit No. (SCE-1)_____ shows that construction expenditures and refundings during the 1979-1983 period are currently expected to total $3.4 billion, or about 42% more than required during the 1974-1978 period.

Without rate relief, at least $2.9 billion, or about 87% of the cash funds needed, would have to be obtained from financial markets during the 1979-1983 period. This amount of financing, even if possible, would seriously damage Edison's financial integrity, credit standing, and ability to continue to attract capital.

Q. How much rate relief is required to achieve earnings results sufficient to enable Edison to meet its financing requirements and maintain its financial integrity, credit standing, and ability to continue to attract capital?

A. Edison needs to reduce its average dependence on financial markets for cash funds to 60% in the long run; otherwise, Edison will not be able to maintain its financial integrity, credit standing, and ability to continue to attract capital.

Table 1 of Exhibit No. (SCE-1)______ shows that with the rate relief requested in this filing for 1981, the balancing account to compensate for the addition of San Onofre Unit No. 2 to rate base and revenues needed to produce a 15% return on common equity in 1983, Edison's dependence on financial markets for cash funds is reduced to the 70% level during the 1979-1983 period. While this is not believed to be satisfactory in the long run, it is believed to be satisfactory for the period because of the strong reversal of trend during the 1981-1983 period. The need to obtain about 95% of the funds through external financing during 1979-1980 must be followed by less demanding years for Edison to maintain its financial well-being.

Q. How do you expect the construction program and refundings to be financed during the 1979-1983 period?

A. Table 2 of Exhibit No. (SCE-1)______ shows the amount of long-term debt, preferred stock, and common stock that will be needed during the 1979-1983 period to finance the construction program, refundings, and to maintain the target capital structure.

While Table 2 of Exhibit No. (SCE-1)______ shows a schedule of financings without rate relief, that schedule should be regarded in light of the fact that it assumes the Company's financial integrity, credit standing, and ability to continue to attract capital would not be seriously damaged. This would not be the case, but the full impact cannot be completely predicted through financial simulation. The diminished earnings would (at the very least) greatly increase the cost of financing because the Company's bonds and preferred stock would be derated one or more times, legal investment laws in several states would not be met, and the common stock dilution would be devastating as the common stock price fell and the number of shares sold would need to be greatly increased to raise the necessary funds. In the worst case, however, the Company might be unable to obtain the furds required.

Table 2 also shows a schedule of financings based upon the effect of the requested rate relief in 1981, rate relief to fully compensate for the addition of San Onofre Unit No. 2 on about July 1, 1981, and additional rate relief sufficient to earn a 15% return on common equity in 1983. This schedule of financings shows that the external cash requirement is about 71% greater than the $1.4 billion raised during the 1974-1978 period. The $2.4 billion required to be raised during the 1979-1983 period under these assumptions is comprised of $1.6 billion debt. $337 million preferred, and $547 million common stock. While this amount is large, it is believed to be manageable and should not harm the financial integrity and credit standing of the Company as long as the earnings assumed are achieved with regard to common equity.

Q. What is the target capital structure during the 1980-1982 period?

A. The financings shown on Table 2 of Exhibit No. (SCE-1)_____ are designed to achieve, during the 1980-1982 period, a capital structure average of about 47% debt, 13% preferred stock, and 40% common equity, the Company's target capital structure for that period. These ratios are used on Table 24 of Exhibit No. (SCE-1)____ to determine Edison's over-all cost of capital in 1981 and 1982. This capital structure reflects a reduction of one percent in both the debt and preferred stock ratios from the target ratios of 48% debt, 14% preferred stock, and 38% common equity used during the 1977-1979 period. The reductions in debt and preferred stock ratios have been made in an effort to help maintain financial integrity and credit standing of the Company and to reduce Edison's over-all cost of capital needed to maintain its times interest earned after tax ratio close to three times.

Q. Why do you expect senior financing costs to be high relative to Edison's debt and preferred imbedded costs?

A. Even with the rate relief required to maintain financial integrity, credit standing, and the ability to continue to attract capital, Edison's financing cost of debt and preferred stock will be much higher in the future than its imbedded costs. One reason is Edison's increased dependence on capital markets. The need to enter the market more frequently and with larger issues for cash funds reduces the ability of Edison to time issues to either take advantage of short-run conditions or to avoid adverse market conditions. A second reason is that energy and ecological requirements have increased investment demands on finite capital markets at the same time that government deficits are expected to be very large. Since the saving rate has not increased, the added demand pressure increases investment costs. A third reason, which is probably the most important reason, is the level of inflation. Investors' inflationary expectations have been affected by the experience of the past several years.

Table 3 of Exhibit No. (SCE-1)____ shows the three major price index measures: The GNP Implicit Price Deflator, the Consumer Price Index, and the Producer Price Index. Since 1969, all three indicate an average inflation rate in excess of 6.6%. This experience and economists' forecasts indicate investor expectations should exceed that amount. Edison expects the inflation rate to average in excess of 8% during the 1979-1983 period, with investors expecting about a 7% inflation rate in the long run. The investors' long-run inflationary expectations are important because they are a component of the cost of capital. Otherwise, the investor would be unable to achieve the return goal required to attract his funds after the inflationary effect is subtracted. While the short-run inflationary experience has an impact on inflationary expectations, the two are not the same; and it is inflationary expectations that affect the level of the cost of capital, not the short-run experience.

Q. How have money rates, bond yields, and preferred stock yields compared to Edison's imbedded costs during the past ten years?

A. Money rates, bond yields, and preferred stock yields have exceeded imbedded costs over the past ten years. This experience would also tend to further support the expectation that bond and preferred stock yields would continue to exceed Edison's imbedded costs.

Q. What has been the experience with regard to money rates?

A. Table 4 of Exhibit No. (SCE-1)_____ shows short-term money rates fluctuated from about 4% to 12% during the 1969-1978 period. While the money rates differ among themselves somewhat, note how each approximates the inflation rates over the ten-year period. Only 90-day Treasury Bills average less than 6.6% during the 1969-1978 period.

Chart 1 of Exhibit No. (SCE-1)_____ draws the parallel between inflation rates and money rates even closer. Note how 4-6 month commercial paper rates on a year-by-year basis move with the GNP Implicit Price Deflator. This indicates that Edison's short-term money rates should not be expected to be less than the inflation rate for any reasonable length of time.

The current high short-term money rates tend to support higher inflationary expectations.

Q. What has been the experience with long-term bond yields?

A. Table 5 of Exhibit No. (SCE-1)_____ shows Moody's Aa, A, and Baa Public Utility bond yields and U.S. Government long-term bond yields. The Aa bond yields represent Edison's bond class, while the A and Baa bond yields represent the potential increased bond yield cost to Edison of being derated one or two times. Chart 2A shows how these yields tend to move in the same pattern. Note that during the 1969-1978 period, Aa, A, and Baa bond yields averaged about 8.4%, 8.7%, and 9.1%, respectively, with the yields generally being higher after 1973.

Since the U.S. Government long-term bond yields represent the risk-free rate, the differential between the Aa bond yields and the U.S. Government bond yield represents the risk premium investors demand to purchase Aa Public Utility bonds. Note that in 1979, even U.S. Government long-term bond yields exceeded 9%, while the Aa bond yields approached 10%.

Chart 2B of Exhibit No. (SCE-1)_____ shows that while Moody's Aa Public Utility Bond Yields are generally higher than the GNP Implicit Price Deflator, the movements of the two are similar.

Q. What has been the experience with regard to preferred stock yields?

A. Table 6 of Exhibit No. (SCE-1)_____ shows Moody's aa, a, and baa Public Utility Preferred Stock Yields since September 1975 when Moody's started publishing preferred yields by rating. Table 6 and Chart 3A show that a and baa preferred stock yields move in a pattern similar but higher than aa preferred stock yields. Chart 3B shows that Moody's aa Public Utility Preferred Stock Yields and Aa Public Utility Bond Yields move in a highly correlated manner but that aa preferred yields move at a level somewhat below that of Aa bond yields.

Q. What do you expect Edison to pay for long-term debt and preferred stock through 1982?

A. Based upon the data in Tables 3, 5, and 6; Charts 1, 2B, and 3B; and my estimation of investor expectations and of the financing situation, I expect Moody's Aa Public Utility Bond Yields and Moody's aa Preferred Stock Yields to average 9.75% and 9.50%, respectively. If Edison receives rate relief sufficient to maintain its financial integrity, credit standing, and ability to continue to attract capital, I would expect Edison yields to approximate the Aa and aa levels of 9.75% and 9.50%, respectively. If Edison's rate relief is not sufficient, it will have to pay more than the Aa bond yield and aa preferred stock yield, as indicated on Tables 5 and 6, and Charts 2A and 3A. Without rate relief, Edison might find it imprudent, if not impossible, to continue to finance its construction program.

Q. What will happen to Edison's imbedded costs of debt and preferred stock as a result of the financings required during the 1979-1983 period?

A. Table 7 of Exhibit No. (SCE-1)_____ shows Edison's imbedded costs of debt and preferred stock during the recorded period through June 1979 and during the forecast period through 1982.

With rate relief as required, the imbedded cost of debt would rise from 6.87% in 1978 to 8.03% in 1981, and then to 8.30% in 1982; and the imbedded cost of preferred stock would rise from 7.13% in 1978 to 7.80% in 1981, and then to 7.90% in 1982. These projections are made with the financings shown on Table 2 of Exhibit No. (SCE-1)_____ and the 9.75% debt cost and 9.50% preferred cost assumption for financings made after 1979.

Without rate relief, the capacity to issue debt and preferred stock would be reduced to where sufficient financing to continue the construction program would not be expected. In addition, the cost of each new issue would increase above that presumed for double-A securities. Therefore, imbedded costs are not projected without rate relief.

Q. What has Edison done to reduce its financing needs and to reduce the level of its debt and preferred stock costs?

A. The Company has done much to reduce its financing needs and capital costs. These include load management and capital rationing efforts, productivity and managerial effectiveness programs, capital structure changes, and innovative financing methods.

Q. Have load management and capital rationing efforts reduced Edison's construction expenditures?

A. Yes, Table 8 and Chart 4A of Exhibit No. (SCE-1)_____ show that substantial reductions have been made to plant expenditures programs for the 1979-1983 period. These changes have been possible because of Edison's success in reducing kWh sales and kW demand growth during this period, as shown on Table 8 and Charts 4B and 4C of Exhibit No. (SCE-1)_____. In addition, the Company's strict review and budgeting procedure in the Plant Expenditure Review Committee (PERC) and the evaluation process for resource planning encourage the efficient use of funds.

Q. What else has been done to reduce cash needs from investors?

A. The Company has a strict budgeting process, sometimes referred to as a modified zero-based budgeting procedure, under the direction of a Budget Director and the Budget Committee to assure efficient allocation of resources to the functioning of the Company. In addition to elimination of waste and redundancy, the Company has focused on increasing productivity. A Productivity and Managerial Effectiveness Committee was formed in 1978 with the President of the Company as chairman to emphasize its importance. A work group was also formed to measure the progress of the Company with regard to itself and to others. The superior performance of the Company, when compared to similar utilities, is shown on Table 9 and Charts 5A, 5B, and 5C of Exhibit No. (SCE-1)____. Edison's performance has been superior to that of the 20 largest electric utilities with regard to controlling the growth of employees, kWh sales, and electric plant.

Q. What has Edison done to reduce debt and preferred stock financing costs?

A. In addition to reducing the amount of cash funds required from financial markets, the major changes the Company has implemented include the reduction of the debt ratio and the use of appropriate cost-effective financings.

Table 10 and Chart 6 show that Edison reduced its debt ratio from 53.8% in 1969 to 48.1% in 1978, while the 20 largest electric utilities did much less, declining from 52.8% to 51.4% during the period. By reducing its debt ratio, Edison reduced the amount of debt it sold by $350 million by 1978 and its 1978 imbedded debt cost by 20 to 28 basis points. In addition, Edison's times interest earned ratio was maintained. This helped to maintain Edison's Aa bond rating.

Some of the innovative financings which held the Company's imbedded costs down included nuclear fuel and other lease arrangements, project financing, pollution control bonds, intermediate-term bonds, off-shore preference stock, private placement of bonds and preferred stock, foreign financing through the Export Credit Guarantee Department, and foreign financing through an investment banker.

Q. How successful has Edison been in reducing debt and preferred stock costs?

A. Table 11 of Exhibit No. (SCE-1)____ shows nominal debt and preferred stock costs for Edison and the 20 largest electric utilities. Since

Edison's debt and preferred costs are well below the average of the 20 largest, it can be said that Edison has been more successful in controlling its costs than the comparable utilities.

Q. You have shown that reduction of bond and preferred stock ratings increases bond and preferred stock yields. How does this impact the ratepayer?

A. Increased bond and preferred stock yields mean higher imbedded costs, and this causes the rate of return requirement to be higher. Thus, the cost of service paid by the consumer is greater. Decreased bond and preferred stock ratings also affect the size of the issue and the width of markets available to it.

This is important because Edison must obtain $600 million cash per year to continue its construction program. Therefore, the size and frequency of issue is important. For example, in 1978, the largest Aa electric utility bond issue was $250 million while the largest Baa electric utility bond issue was $100 million. This means that the Aa electric utility, if derated to Baa, would have gone to the market over two times as much in 1978 to raise the same amount of money. Since market conditions vary, the impact on a large company such as Edison could be serious for reasons other than costs, such as a practical limit on the number of times any company can enter the financial market in a year as investors strive to diversify their portfolios.

The width of market is also important. Many fiduciaries limit themselves to Aa electric utility bonds because of the "prudent man" rule. State legal investment laws may bar entry of insurance companies, savings banks, and other large investors in their states if certain criteria are not met.

Q. Why do investors turn away from lower-rated utilities?

A. The two primary reasons are: (1) fear of investment loss, and (2) returns insufficient to compensate for the perceived risk.

The return differences are shown on Tables 5 and 6 and Charts 2A and 3A of Exhibit No. (SCE-1)_____. One dimension of the risk that detours investors from a utility about to lose its bond or preferred stock rating is the loss of investment. Tables 12 and 13 of Exhibit No. (SCE-1) _____ show that when the yield changes as a result of, or in anticipation of, a derating, the bond or preferred stock investor immediately loses a portion of his investment as it is devalued. If they are doubtful about the credit standing of the utility, those who continue to invest will discount the bonds and the preferred stock. However, the more doubt, the fewer the investors; and under certain market conditions, other investments may take all the funds available.

Q. Does the risk of devaluation of investment pertain to common stock as well as to bonds and preferred stock?

A. Yes. Studies indicate that investors also require a higher return on common equity to invest in lower-rated companies than in higher-rated companies. Chart 7 of Exhibit No. (SCE-1)_____ shows that the earnings/price differential between Aa and A public utilities varied from 7 to 128 basis points during the 1974-1978 period.

When an electric utility's common stock price falls below book value, sales of additional shares of common stock dilute the investment of each share in the utility. Table 14 of Exhibit No. (SCE-1)_____ shows that since 1974, Edison's common stockholders suffered a 10.1% loss in book value and earnings per share as a result of common stock sales below book value. It also shows that the Company was required to issue about 6.4 million more shares during the 1974-1978 period than it would have if common stock had sold at book value during the period. The cash drain caused by these additional shares at the current annual dividend rate of

$2.72 is about $17 million per year.

Q. How does dilution work?

A. The revenue requirement for electric utilities in California is based upon original cost of plant less accumulated depreciation, i.e., book value. The book value per common share represents the portion of the original cost of the investment in plant less accumulated depreciation that is assigned to each share of common stock. In effect, it represents the common equity investment per share upon which the Commission allows a return. If the price of new shares falls below book value (the price of the previously-sold shares plus retained earnings per share - earnings not distributed as cash dividends), the common equity investment per share decreases.

This happens as follows. Assume two shares of common stock with book values of $20 each, earning a 15% or $3.00 annual return per share, and $40 additional funds are needed. The price of the stock determines the number of shares needed to raise the $40. If the price per share is $20, two shares will be needed, and no dilution will occur because price equals book value ($20 + $20 + $20 + $20 = $80/4 shares $20 x 15% = $3.00 per share). However, if the price per share is $10, or half of book value, four shares will be needed and dilution will occur ($20 + $20 + $10 + $10 + $10 + $10 = $80/6 shares = $13.33 x 15% = $2.00 per share).

The following table shows the impact of selling common stock both above and below book value.

	Shares			Investment				Earnings at 15%	
Case (1)	Start (2)	Added (3)	Total (4)	Start (5)	Added (6)	Total (7)	Per Share (8)	Total (9)	Per Share (10)
A	2	2	4	$40	$40	$80	$20.00	$12.00	$3.00
B	2	4	6	40	40	80	13.33	12.00	2.00
C	2	1	3	40	40	80	26.67	12.00	4.00

Q. Why do you feel Edison needs a rate of return allowance above the 10.78% rate of return in 1981 based upon a 15% return on common equity and a balancing account to compensate for the addition of San Onofre Unit No. 2 in 1982?

A. The Company needs the higher rate of return allowance in fixing rates on the basis of the 1981 cost of service to compensate for the fact that estimates of imbedded senior capital costs, operating and maintenance expenses, and rate base used for 1981 will be deficient in 1982. Without the additional rate of return adjustment and a balancing account for San Onofre Unit No. 2, the return on common equity and earnings for the 1981-1982 period will be less than what the Commission authorizes. This deficiency will result from the fact that the rate of return and return on common equity in 1982 will fall below what the Commission authorized for 1981 because rates will be fixed on the basis of 1981 costs. This decline in earnings, subsequent to the test year, is often referred to as attrition.

Q. If the need for an attrition allowance is recognized by the Commission in the proceeding, why would a balancing account for San Onofre Unit No. 2 be appropriate? Wouldn't that be duplicative or at least overlapping?

A. No. The attrition allowance, which Edison has requested in this proceeding, does not include either the operating cost or rate base effects caused by adding San Onofre Unit No. 2 to rate base.

Q. What is the cause of attrition?

A. It is related to primarily three factors which are: (1) financing costs of debt and preferred stock in excess of their respective imbedded costs, (2) inflation rates at the 8% and greater levels, and (3) additions to rate base which reflect both inflation rates and internalization of social costs resulting in a higher rate base per unit of output.

Q. How do the higher financing costs of debt and preferred stock cause attrition?

A. Table 7 of Exhibit No. (SCE-1)______ shows that Edison's imbedded cost of debt will rise from 8.03% in 1981 to 8.30% in 1982, and its imbedded cost of preferred stock will rise from 7.80% in 1981 to 7.90% in 1982 as a result of 1982 debt and preferred stock financing costs in excess of 1981 imbedded costs. Table 24 of Exhibit No. (SCE-1)______ shows that when these imbedded debt and preferred stock costs are multiplied by the 47% debt and the 13% preferred stock ratios, the weighted cost components for the two rise from 4.78% in 1981 to 4.93% in 1982, an increase totaling 15 basis points. Table 24 shows that even with the other components of the cost of capital unchanged, a 15 basis point increase in the total cost of capital occurs during the 1981-1982 one-year interval. However, if no rate relief is afforded and everything else remains the same as in 1981, the return on common equity would drop 37 basis points as shown below:

Return on Common Equity Attrition When
Total Return on Capital is Not Increased But
Imbedded Cost of Debt and Preferred Stock Increases

	Target Capital Ratios	1981 x Cost Factor =	1981 Weighted Cost	1982 x Cost Factor =	1982 Weighted Cost
Debt	47.00%	8.03%	3.77%	8.30%	3.90%
Preferred	13.00	7.80	1.01	7.90	1.03
Fixed Costs	60.00%	7.97%	4.78%	8.22%	4.93%
Common Equity	40.00	15.00*	6.00	14.63**	5.85
Total Capital	100.00%		10.78%		10.78%

* 1981

10.78% Total Cost of Capital - 4.78% Fixed Costs = 6.00% Weighted Cost of Common Equity/40.00% Common Equity Ratio = 15.00% Return on Common Equity.

** 1982

10.78% Total Cost of Capital - 4.93% Fixed Costs = 5.85% Weighted Cost for Common Equity/40.00% Common Equity Ratio = 14.63% Return on Common Equity.

This demonstrates the need for the Commission to make an adjustment in the rate of return based on the 1981 cost of capital to compensate Edison for its 1982 financing cost attrition since general rate increases are to be spaced at two-year intervals.

Q. How is times interest earned affected by increased financing costs?

A. For Edison to maintain its financial integrity and credit standing, it must maintain its times interest earned ratio. For 1981, a 10.78% return on capital provides a 2.86 times interest earned after tax, as shown on Table 24 of Exhibit No. (SCE-1)_____. If the return on capital were to remain at 10.78% in 1982, the times interest earned after tax ratio will fall to 2.76 times (10.78%/3.90%). With the return on capital increased to 10.93% to maintain earnings and the return on common equity at 15.00%, the times interest earned after tax ratio still declines somewhat, falling to 2.80 times.

This change in interest coverage resulting from much higher debt costs is another reason why Edison has needed to reduce its debt ratio from about 54% in 1969 to about 47% in 1981. Without that change, the cost of common equity to maintain Edison's financial integrity, credit standing, and ability to continue to attract capital would be much higher. It is also logical that when it takes 9.75% to attract bond investors, compared to the past costs which averaged about 8.00% for Edison, the return on common equity will need to increase at least as much to attract common stock investors; otherwise, the common stock price will fall in order for the incoming investors to get their risk premium. Existing Edison investors would lose the difference.

Q. How does inflation cause attrition?

A. Edison expects its costs, exclusive of fuel costs and income taxes, to increase about 8% during 1982. While Edison is proud of its past productivity and managerial effectiveness gains, as reflected on Table 9 and Charts 5A, 5B, and 5C of Exhibit No. (SCE-1)_____, any future gains cannot be expected to compensate for price level increases resulting from increased labor costs, material and supply costs, and contract costs. This is especially true since regulatory and legislative costs are expected to continue to increase the cost of service without increasing output.

It should be noted that during the 1974-1978 period Edison increased output per manhour at an annual trend rate in excess of 3% while both U.S. Gas and Electric Utilities and U.S. Non-farm Business were able to achieve averages of less than 2% during the same period.

Q. How does the addition to rate base reduce the return on common equity?

A. The Commission authorizes a rate of return on rate base for the test year. This return on rate base can be affected by changes in revenues, expenses, and rate base as shown by the following formula:

$$\text{Percent Return on Rate Base} = \frac{\text{Revenues - Expenses}}{\text{Rate Base}} \times 100$$

If the rate base increases, the rate of return, or percent return on rate base, is reduced unless either revenues increase or expenses decrease sufficiently to compensate for the change in the rate base.

Since the return on rate base will decline and the fixed costs for debt and preferred stock will not, the return on common equity will absorb all the impact of the decline in common equity. With the common equity ratio of 40%, the impact on the common equity return will be two and one-half times the impact on the return on rate base.

Since San Onofre Unit No. 2 is scheduled to be in operation in mid-1981, it would substantially reduce Edison's rate of return in 1982 unless revenues are adjusted to compensate. Since the ECAC procedure will flow through the benefit of reduced energy costs to ratepayers as San

Onofre Unit No. 2 increases production, the revenue increases needed to compensate for the operating costs and rate base additions associated with San Onofre Unit No. 2 should be largely offset by the energy cost benefit. Therefore, the Company is requesting, by separate application, that the Commission establish a balancing account procedure to deal with the revenue requirements associated with the addition of San Onofre Unit No. 2. If such a procedure is not implemented, the Commission should make an additional attrition allowance because neither the operating costs nor the rate base additions associated with San Onofre Unit No. 2 have been included in the base rate or attrition allowance requests in this application.

Q. Why should the return on common equity be greater than the return on common equity authorized in Decision No. 89711 for 1979?

A. There are several reasons. Primarily, Edison's return on common equity must be raised to a level that is commensurate with the cost of capital if it is to be able to maintain its financial integrity, credit standing and ability to continue to attract capital. Some of the specific causes include:

1. Edison's large financing needs require maintenance of bond and preferred stock ratings and the ability to sell common stock at book value or higher if it is to maintain financial integrity and be able to attract the capital required in the long run.
2. An allowance must be made for investors' increased inflationary expectations.
3. Since the cost of Edison's bonds and preferred stocks have increased, the return on common equity must be increased in order to maintain the risk premium.
4. The common stock price performance of Edison and comparable utilities in relation to their earnings and the price performance of unregulated enterprise indicate that a higher

return on common equity is both justified and required.

5. Edison's earnings/price cost of capital on a discounted cash flow (DCF) basis indicates a 15% return on common equity is required.

6. An allowance needs to be made for the increase in risk perceived by investors.

Q. How do Edison's large financing needs impact the return on common equity requirement?

A. Table 1 of Exhibit No. (SCE-1)_____ demonstrates that Edison must earn in excess of a 15% return on common equity in 1981 and 1983 and receive sufficient revenues to compensate for the impact of San Onofre Unit No. 2 on earnings in 1982 to achieve 40% internal cash generation. Since Edison must average 40% internal cash generation in the long run to maintain its financial integrity, credit standing, and ability to continue to attract capital, Edison's large financing needs make it vital to the continued adequacy of service that its authorized return on common equity should be raised from 13.49% to at least 15.00% in 1981.

Q. How do inflation rates demonstrate that Edison requires a higher return on common equity than authorized in Decision No. 89711 for 1979?

A. Table 3 of Exhibit No. (SCE-1)_____ shows that the inflation rate averaged over 6.6% during the 1969-1978 period. While this rate is expected to average in excess of 8% through 1983, investors' inflationary expectations in the long run are believed to be at about the 7% level.

For Edison's common stock investors to maintain equivalent cash income, their cash dividends must rise at the same rate as the inflation rate. It would follow that Edison's stock price would not be discounted below book value as long as dividends grow at a rate equivalent to investors' long run inflationary expectations. In order to sustain a dividend growth rate, dividends cannot, in the long run, grow at a rate faster than earnings. The two, in the long run, must grow at the same rate. Earnings per share (and thus dividends per share) can grow at a 7% rate in the long run if the following conditions can be met:

1. The price is equal to book value and the following combination of return on common equity and retained earnings after dividends:

Retained Earnings	X	Return on Common Equity	=	Earnings Growth
35%		20.00%		7.0%
40		17.50		7.0
45		15.56		7.0

2. Price 20% greater than book value with sales of 5% of common per year and the following combination of return on common equity and retained earnings after dividends:

Retained Earnings	X	Return on Common Equity	+	Benefit From Sales	=	Earnings Growth
35%		17.14%		1.0%		7.0%
40		15.00		1.0		7.0
45		13.33		1.0		7.0

Since Edison is committed to maintaining a payout in the range of other utilities (about 65%), the above examples show that a return on common equity in excess of 15% is needed to avoid downward stock price pressure.

Q. Does the composition of Edison's common stock investors impact the sensitivity of Edison's ability to increase dividends sufficiently to compensate for the impact of inflation?

A. Yes. Edison has many common stock investors who are dependent on dividends for income. Many of these are retired persons whose incomes would otherwise be fixed. For example, Edison's common stock investors total 138,032 with the average holding per investor being only 457 shares. However, registered individual holdings average only 174 shares per individual. While individuals comprise the largest group, institutions hold 22.8% of Edison's outstanding common stock. These institutions consist largely of insurance companies, pension funds, and other fiduciaries.

Q. How does the cost of bonds and preferred stock indicate an increase in required return on common equity?

A. There are two ways that the cost of bonds and preferred stock affect the cost of common equity. First, a risk premium is required to attract the investor from the less risky bond and preferred stock investment to the common stock investment. Even if this premium does not increase as bond and preferred stock yields rise, the earnings required for a given stock price will rise. If these earnings expectations do not rise, the common stock price will fall. Since Edison's cost of debt has increased about 75 basis points since 1978, the cost of common equity of at least as much should be allowed. Table 22 and Chart 8 of Exhibit No. (SCE-1)_____ show the risk premium investors require to invest in common equity versus debt. This is done by showing the difference between Aa bond yields and Edison's return on common equity adjusted for price/book ratio differentials.

Second, the return on common equity requirement is related to imbedded cost level because coverage must be maintained if Edison's financial integrity and credit standing are to be maintained. When imbedded costs rise, interest coverage can be maintained by raising the return on common equity and reducing the debt ratio. Edison has reduced its target debt ratio one percentage point from the 1977-1979 level. However, this alone is not sufficient to maintain the times interest earned after tax ratio, as shown below using the 13.49% return on common authorized in Decision No. 89711 for expository purposes only:

	1979			1981		
	Capital Ratios	Cost Factors	Weighted Cost	Capital Ratios	Cost Factors	Weighted Cost
Debt	48.0%	7.40%	3.55	47.0%	8.03%	3.77%
Preferred	14.0	7.40	1.04	13.0	7.80	1.01
Common	38.0	13.49	5.13	40.0	13.49	5.40
Total	100.0%		9.72%	100.0%		10.18%

9.72%/3.55% = 2.74x   10.18%/3.77% = 2.70x

For the 2.74x to be maintained even after the capital structure changes, the return on common equity would have to be raised 39 basis points*. Table 24 of Exhibit No. (SCE-1) _____ shows that at least a 15% return on common equity is required in 1981 to maintain the 2.8 times interest earned after tax that is the minimum level necessary to maintain an Aa bond rating.

Q. Why are comparable earnings data significant in determining the appropriate return on common equity?

A. The <u>Hope</u> and <u>Bluefield</u> cases established comparable earnings as one of the tests required to be met in determining the reasonableness of utility rates.

Q. What are the problems in applying comparable earnings?

A. The first problem is to identify a comparable group that also meets the financial integrity, credit standing, and capital attraction tests of the <u>Hope</u> and <u>Bluefield</u> decisions. The second problem is the avoidance of circularity (e.g., inadequate returns for one company used to justify inadequate returns for another company). The third problem is to determine if the earnings of the comparable group have been adequate.

Q. What criteria have you used to identify the comparable group of companies in order to meet the financial integrity, credit standing, and capital

* 10.33%/3.77% = 2.74x
10.33% - 3.77% - 1.01% = 5.55%/40.0% = 13.88% - 13.49% = 0.39%

attraction tests?

A. The selection criteria for the comparable group has been made as follows:

1. The companies should be regulated utilities which receive at least 90% of their revenues from electric utility operations. This assures that the group is engaged in essentially the same business as Edison and indicates that their business risks are similar.
2. The bonds of these utilities should have been rated no less than single-A by both Moody's and Standard and Poor's during the past five years. Since bond ratings indicate credit standing and level of financial integrity, this assures that the utilities selected will be similar to Edison with regard to credit standing and financial integrity.
3. The common stocks of the utilities should be traded on the stock exchanges and be widely held. This provides a basis to test the adequacy of returns on common equity through price performance with regard to the capital attraction test.
4. The utilities should be relatively large with large capital needs in order to be similar to Edison. This avoids scale problems and includes utilities with similar capital needs.

Q. Please describe the comparable group you have selected for comparable earnings analysis.

A. Tables 15 and 16 of Exhibit No. (SCE-1)_____ list the 20 largest electric utilities. Table 15 ranks the 12 double-A and 8 single-A utilities by operating revenues, shows the percent electric, and also provides fuel expense and labor expense data. Table 16 indicates the bond ratings, deratings, shares outstanding, number of shareholders, shares per stockholder, percent of shares held by institutions, net utility plant, and the magnitude of construction expenditures relative to net utility plant.

Q. How have you avoided the problem of circularity?

A. Circularity with regard to the 20 largest electric utilities has been avoided as follows:

1. Several jurisdictions regulate the 20 largest electric utilities; thus, a cross section of regulators' judgments are represented.
2. These regulators' judgments are made at diverse times and intervals.
3. The common stock price performance of the 20 largest electric utilities reflect investors' judgments as to the adequacy of the book returns.
4. The 20 largest electric utilities' price performance may be compared to that of unregulated enterprise as an independent test of relative attractiveness. Standard and Poor's Industrials have been used to represent unregulated enterprise.

Q. What comparable earnings data have you provided?

A. Tables 17 and 18 of Exhibit No. (SCE-1)_____ show the comparable earnings data for Edison and the 20 largest electric utilities. Table 17 shows earnings and dividends per share comparisons. The growth in the inflation rate since 1969 exceeded that of Edison and the 20 largest electric utilities. This means that utility investors have not maintained parity with inflation over the period. However, during the 1974-1978 period, Edison's earnings and dividends per share growth, while still less than Standard and Poor's Industrials, exceeded that of the 20 largest electric utilities and the rate of inflation.

The circumstances which allowed Edison's earnings and dividends per share growth to exceed 7% on a trended basis during the 1974-1978 period, unfortunately, cannot be sustained. First, the increase in the return on common equity from the depressed 1974 level of 9.5% to the 1976-1977 level of 12.1%, as shown on Table 18, accounted for the sharp earnings per share rise. Second, the change in dividend policy to increase the payout from a historical level averaging about 55% to a level more commensurate with the electric utility industry average accounted for the unsustainable increase in dividends per share. The following example shows the tremendous impact of these two changes:

Book Value	X	Return on Common Equity	=	Earnings Per Share	X	Payout	=	Dividends Per Share
$30.00		9.5%		$2.85		55%		$1.57
30.00		12.0		3.60		65		2.34
Growth				26.3%				49.0%

Earlier testimony demonstrated that when 35% of earnings per share are retained, the return on common equity must exceed 15% for a 7% earnings per share growth to be sustained. Table 18 shows that while the 20 largest electric utilities' average returns on common equity were higher than those for Edison during the 1969-1978 period, they were not sufficient to provide earnings per share growth to match investor expectations of a 7% inflation rate in the long run.

Since investors expect the inflation rate to be at about 7% in the long run, Tables 17 and 18 indicate that Edison and the 20 largest group require returns on common equity in excess of 15%.

Q. Have you tested to see if investors believe that the returns on common equity earned by Edison and the 20 largest electric utilities are adequate?

A. Yes. Tables 19, 20, and 21 of Exhibit No. (SCE-1)_____ indicate the price performance of Edison, the 20 largest electric utilities, and

Standard and Poor's 400 Industrials. These data all indicate that the returns on common equity for Edison and the 20 largest group have been inadequate.

Table 19 shows that through 1978, the stock prices of the 20 largest electric utilities and Edison are depressed, while the price index for Standard and Poor's Industrials is not.

Table 20 shows the earnings/price ratios for Edison, the 20 largest group, and Standard and Poor's Industrials. These earnings/price data reflect the relative attractiveness with Edison being the least attractive and the 20 largest group being more attractive than Edison but less attractive than unregulated enterprise, as represented by Standard and Poor's Industrials.

Table 21 shows the price/book ratios with Edison the least attractive and the 20 largest group more attractive than Edison but less attractive than unregulated enterprise. In addition, Edison's common stock price remained well below book value during each year of the 1973-1978 period, and the 20 largest group's price/book ratio averaged just less than one during the same period, although exceeding book value in four out of six years.

Q. What conclusions can be drawn from these comparable earnings and price performance data shown on Tables 17, 18, 19, 20, and 21 of Exhibit No. (SCE-1)_____?

A. The returns on common equity for Edison and the 20 largest electric utilities have been inadequate, especially subsequent to 1973. For the purchasing power of earnings and dividends per share to be maintained, a return on common equity in excess of 15% is required. Since Edison and the 20 largest electric utilities have not achieved such earnings, their common stock prices have fallen, earnings/price ratios have risen, and price/book ratios have fallen to less than one.

In addition, Edison's price performance indicates a return on common equity requirement in excess of 15%. First, Edison's earnings/price ratio during the 1974-1978 period reflects an investor requirement of 15.1%, as shown on Table 20 of Exhibit No. (SCE-1)_____. Second, Table 22 of Exhibit No. (SCE-1)_____ reflects the investor return on common equity requirement to raise Edison's price to book value. With price as a function of return, a 14.9% return on common equity average is shown to be required to raise Edison's price to book value since it fell below book value in 1973.

Q. What other measures have you employed to demonstrate Edison's need for a return on common equity in excess of 15%?

A. Table 23 of Exhibit No. (SCE-1)_____ provides two comparisons. The first method compares the recorded earnings per share to the average monthly high-low price recorded during the same year. On this basis, the cost of common stock during the 1974-1978 period averaged 15.6%.

The second method uses five years of recorded data to provide the expected earnings per share extrapolated by exponential curve fit. These trend earnings per share are then compared to year-end price. On this basis, the cost of common stock during the 1974-1978 period averaged 16.0%.

Q. Was risk considered in determining Edison's cost of common equity?

A. Yes. As indicated earlier, a comparable group was selected to present the investor a similar risk situation in order that the comparable requirement would be satisfied in determing the cost of common equity.

Q. What risks do these utilities and Edison now face that may have changed their cost of capital in recent years?

A. Edison's depressed stock price since 1972 and that of comparable utilities indicate that the authorized and earned returns on common equity have not increased sufficiently to compensate for the increased risk.

Q. Why do you believe that investors perceive an increase in risk associated with Edison's comparable utilities' securities in recent years?

A. While there is no certainty that either an exact or a complete list of reasons for investors' perceptions can be captured, some examples can be listed as to why investors perceive that the risk associated with an investment in Edison and comparable electric utilities have increased. In doing so, the risks will be separated into two classifications - business and financial. The business risks include:

1. The fear of loss of investment has received increased attention. The Three Mile Island incident demonstrated that even after state and federal regulatory approvals, a multi-billion dollar investment can be lost, and unlimited lawsuits can follow into the distant future.
2. Plant siting problems continue to increase. Millions are spent on feasibility and environmental impact studies before applications for operating permits are considered.
3. Environmental concerns make operating conditions and costs relating to new and existing generating facilities uncertain. Environmental control standards and requirements are unstable, and many are based on "state-of-the-art" technology before testing.
4. Special interest and consumer harassment continues to increase with outcomes uncertain, but over-reaction is often the result.
5. Longer lead times to build more costly generating facilities increase financial problems, placing many utilities in the

position that the failure of one project could mean the failure of the company.

6. Edison's dependency upon oil-fired generation is a concern. Availability of low sulfur fuel oil originating primarily from overseas sources is less certain than in the past.
7. While the fuel adjustment clause reduces the impact of increased risk associated with the rising cost of fuel oil, it does not eliminate the risk. At the same time, it introduces cash flow problems and regulatory risk. Under-collections in excess of $100 million are not uncommon. These accumulate while the costs already incurred for fuel are reviewed with no certainty that all will be recovered.
8. The magnitude of Edison's fuel cost increases places additional pressure on regulators to resist other needed rate relief.
9. Successful conservation efforts can cause revenues to be less than assumed when fixing the rates authorized.
10. Technological changes are more rapid, increasing the speed of obsolescence and increasing the risk associated with new projects that may not be economically viable.
11. Resale business is more risky than in the past.
    a. The level of energy supplied fluctuates while the capacity to serve to meet total resale customer needs continues.
    b. The timing of when resale customers will drop Edison capacity and energy sales is uncertain.
    c. Participation in generation projects by resale customers follows after the front-end risks are assumed by Edison.

12. Inflation impacts capital-intensive, regulated utilities more than unregulated enterprises.

    a. Rate relief does not keep pace with increased operating and financing costs (attrition).

    b. Investments at a single site become so large that the risk of catastrophic loss increases.

    c. The temptation by regulators to undernourish utilities makes them less able to survive a shock of even less magnitude than the Three Mile Island incident.

13. The effect of price changes, innovative rate designs, conservation and load management efforts, and government regulations on usage makes demand forecasting less certain.

14. Federal and state energy policies are not always clear and consistent. At times, energy policies direct themselves at goals in opposition to other policy, with the result being counter-productive.

The financial risks that have increased include the following:

1. The need to continue to sell common stock below book value to continue the construction program reduces the common equity investment per share which further dissipates the attractiveness of Edison's common stock to investors.

2. The danger of bond and preferred stock deratings increases with the magnitude of financing needs and the higher level of financing costs. Rising imbedded debt costs place pressure on interest coverage.

3. Edison is committed to a construction program to meet consumer demand and cannot postpone construction expenditures. The increased financing needs make the

Company more dependent on and subject to the whims of a finite capital market.

4. The quality of earnings deteriorates as a higher percentage of earnings are comprised of AFDC.

Q. Mr. Christie, have you indicated what Edison's minimum capital costs are?

A. Yes. Table 24 of Exhibit No. (SCE-1)_____ shows that with a 15% return on common equity and the target capital ratios of 47% debt, 13% preferred stock, and 40% common equity, the 1981 composite average cost of capital is 10.78%. A return on rate base of 10.78% in 1981 would allow a 2.86 times interest earned after tax which, in my judgment, would allow the Company to maintain its current bond rating.

Q. Does Table 24 of Exhibit No. (SCE-1)_____ show anything in addition to the 1981 composite cost of capital?

A. Yes. Table 24 of Exhibit No. (SCE-1)_____ also shows Edison's 1982 composite average cost of capital to be about 10.93%. The reason the 1982 composite average cost of capital is 15 basis points higher than the 1981 cost is because the imbedded cost of debt rose 27 basis points while the imbedded cost of preferred stock rose 10 basis points during that same year. The Commission should consider this 15 basis point increase in the composite average cost of capital as part of the attrition allowance requirement when authorizing Edison's 1981 return on rate base.

Q. Do you believe the factual material contained in Exhibit No. (SCE-1)_____ is accurate?

A. Yes.

Q. Insofar as that material in your testimony represents your opinion, does it represent your best judgment?

A. Yes.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Robert P. Haub

Exhibit No. (SCE-2)_____, Chapters 1, 2, and 3

Q. Will you please state your name and address for the record?

A. My name is Robert P. Haub, and my business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company?

A. I am a Supervising Regulatory Cost Specialist in the Company's Revenue Requirements Department.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Robert P. Haub", does that portion of the exhibit accurately set forth your background, training, and experience?

A. It does.

Q. Are you testifying with respect to Chapters 1, 2, and 3 of Exhibit No. (SCE-2)______ for identification, entitled "Results of Operations"?

A. Yes, I am.

Q. Were those chapters prepared by you or under your supervision?

A. Yes, with the exception of Chart 3-B, Summer Generating Capacity and Peak Demand, and Section F - Palo Verde Units 4 & 5, which were prepared for me by the responsible departments. This material will be covered by witness M. D. Whyte in his testimony relating to Chapter 13.

Q. Referring now to Chapter 1, entitled "Introduction", please indicate briefly the purpose and scope of that chapter.

A. The purpose and scope of Chapter 1 is to introduce this exhibit covering the Results of Operations of the Southern California Edison Company, which has been prepared in support of the Company's application for a general increase in its rates for electric service.

Q. Turning now to Chapter 2, entitled "History", please indicate generally what is reflected in that chapter.

A. Section A presents the corporate history of the Southern California Edison Company from its earliest predecessor, which is considered to be West Side Lighting Company, incorporated in California in 1896, through its merger with the California Electric Power Company in 1963. The development of the Company is graphically depicted on Chart 2-A.

Section B presents significant features of electric service history within the territory now served by Southern California Edison Company.

Section C summarizes significant proceedings before the CPUC to which Edison is a party. The decisions included reflect the scope of matters which bring the Company before the CPUC and include plant sitings, rate changes, and general investigation proceedings, among others.

Q. Now turning to Chapter 3, entitled "Present Operations", what does that chapter cover?

A. In general terms, it describes the present operations of the Company.

Q. What information is contained in Section A?

A. Section A describes the territory served. Southern California Edison Company sells electric energy under its certificates of public convenience and necessity in fifteen counties in central and southern California. Electrical service is furnished within these counties to some 800 cities and communities.

A map showing the present division boundaries and district offices is presented on Chart 3-A. The population of the area served was estimated to be 8,062,000 as of December 1978.

Q. With what other electric utility systems does Southern California Edison Company sell, buy, or interchange electricity?

A. The Company sells electric power to the cities of Anaheim, Azusa, Banning, Colton, Riverside, and Vernon. Each of these customers owns the distribution system within its boundaries. Additionally, as of December 1978, electric power was sold to, purchased from, or interchanged with various nonassociated utilities, municipalities, cooperatives, and public authorities, including the State of California, the U. S. Department of Interior, and the Bonneville Power Administration.

Q. Please describe the Company's production facilities.

A. These are described on the table in Section B of Chapter 3. The table shows that at the end of 1978, the Company's generating resources were comprised of 14 oil and gas plants containing 41 steam units, 4 combined cycle units, and 7 combustion turbine units, 2 coal plants with 4 units, one nuclear plant with one unit, one diesel plant with 5 units, and 36 hydro plants consisting of 79 units.

As of December 1978, the total effective operating capacity of these facilities was 13,156,120 kilowatts. Additionally, the Company had 1,201,003 kilowatts of firm capacity available under the terms of purchased power agreements, 100,000 kilowatts from May through October under the provisions of the Portland General Electric Company Assignment Agreement, and from 345,950 to 349,500 kilowatts of seasonally adjusted operating capacity, under generally prevailing conditions, at Hoover Dam and the Parker-Davis Dam sites through contracts with the United States Government.

Q. What does Chart 3-B show?

A. Chart 3-B illustrates the growth of effective generating capacity and summer peak demand from 1969 through 1978, together with planned additions to capacity and expected summer peak demand from 1979 through 1990.

Q. Referring now to Section C of Chapter 3, please describe, briefly, the Company's transmission system.

A. As of December 31, 1978, there were 11,628 circuit miles of transmission lines for voltages between 33 kV and 800 kV, inclusive. This is an increase of approximately 0.7% over the 11,549 circuit miles on December 31, 1977. These lines transmitted power to and between 53 transmission substations, not including generating station switch yards, with an aggregate transformer capacity of approximately 30 million kVA.

Chart 3-C shows the Extra High Voltage Transmission System through 1978.

Q. Please describe, briefly, the Company's distribution system.

A. The electrical distribution system as of December 31, 1978, consisted of approximately 41,446 miles of overhead lines (not including 2,342 miles of distribution lines on transmission poles), approximately 8,403 miles of underground trench with 28,953 miles of underground cable of 16 kV or less. These were supplied from 540 distribution substations with an aggregate capacity of approximately 14 million kVA.

The number of installed electric meters increased from 2,938,615 at the end of 1977 to 3,024,325 at the end of 1978, an increase of 2.9%

Total sales decreased from 57.7 billion kilowatthours during the year 1977 to 57.0 billion kilowatthours during the year 1978, a decrease of 1.2%, as a result of the absence of unusually high energy sales to drought-affected utilities in 1977.

Q. Referring to Table 3-A, what were the principal sources and general disposition of electric energy during 1978?

A. Section A of Table 3-A shows that 68.6% of the energy was obtained from steam, 3.4% from nuclear, 9.2% from hydro, and 1.9% from other generation. Purchased and interchanged power totaled 16.9%. The disposition of this energy is described in Section B. The system load totaled 63.9 billion kilowatthours, of which 89.3% was sold. Energy losses and Company use account for the balance of 10.7%. Of the 57.0 billion kilowatthours sold, domestic use amounted to 27.0%, lighting and small power use was 18.2%, large power customers consumed 24.6%, and the very large power customer use was 16.5%. Remaining sales accounted for the balance of 13.7%.

Q. What is the purpose of the statement regarding the Palo Verde Units 4 & 5 Project outlined in Section F of the exhibit?

A. The purpose of the statement made in the exhibit text is to describe the circumstances surrounding Edison's participation in that project and the cancellation of that project resulting in the abandonment losses reflected in the cost data included in this filing.

Q. Mr. Haub, insofar as the material in Chapters 1, 2, and 3 of Exhibit No. (SCE-2) ______ is of a factual nature, do you believe it to be accurate?

A. Yes, I do.

Q. Insofar as it represents opinion, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Anthony L. Smith

Exhibit No. (SCE-2)______, Chapters 4, 5, and 6

Q. Will you please state your name and address for the record?

A. My name is Anthony L. Smith, and my business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company?

A. Supervisor of Financial Accounting.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Anthony L. Smith", does that portion of the exhibit accurately set forth your background, training, and experience?

A. Yes, it does.

Q. Are you testifying with respect to Chapters 4, 5, and 6 of Exhibit No. (SCE-2)______ for identification, entitled "Results of Operations"?

A. Yes.

Q. Directing your attention now to Chapters 4, 5, and 6 of Exhibit No. (SCE-2)______, were those chapters prepared by you or under your supervision?

A. Yes, they were.

Q. Please briefly indicate what Chapter 4 shows.

A. Chapter 4 reflects the financial position of the Southern California Edison Company. It contains comparative balance sheets, as of December 31, for the years 1976, 1977, and 1978. It also includes explanatory comments relating to some of the accounts contained in the balance sheet as of December 31, 1978.

The balance of the chapter reflects certain detail as to various reserves and to Statements of Changes in Financial Position for each of the years 1976, 1977, and 1978, as shown on Table 4-C.

Q. Please indicate briefly what Chapter 5 shows.

A. This chapter deals with income and retained earnings statements. It contains the following tables:

Table 5-A, Statements of Income, covering the years 1976, 1977 and 1978.

Table 5-B, Statements of Retained Earnings, covering the years 1976, 1977, and 1978.

Table 5-C, Disposition of Earnings, covering the years ended 1976, 1977, and 1978.

Table 5-D, Earnings and Dividends on Common and Original Preferred Stock, for the period 1968 through 1978.

Q. Turning now to Chapter 6, designated "Clearing Accounts", please indicate briefly what this chapter shows.

A. The Company currently maintains 31 clearing accounts used for the purpose of clearing various expenses to job and work orders or to operation and maintenance expense accounts.

Table 6-A is a summary of charges and credits to the various clearing accounts for the years 1976, 1977, and 1978, indicating a volume of charges and credits to these accounts for each of these years.

Q. Mr. Smith, insofar as the material presented in Chapters 4, 5, and 6 of Exhibit No. (SCE-2)______ is of a factual nature, do you believe it to be correct?

A. I do.

Q. In so far as the material in those chapters represents opinion, does it represent your best judgment?

A. It does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of M. D. Whyte

Exhibit No. (SCE-2)______, Chapter 7 (Part 1)

Q. Please state your full name and address for the record.

A. My name is M. D. Whyte. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company?

A. I am the Manager of the Electric System Planning Division of the System Development Department.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of M. D. Whyte", does that portion of the exhibit accurately set forth your background, training, and experience?

A. It does.

Q. Are you testifying with respect to Chapter 7 of Exhibit No. (SCE-2)______ for identification in this proceeding

A. Yes, for Part 1 of Chapter 7 relating to kilowatthour sales and customers, as presented in Table 7-A.

Q. Was Part 1 of Chapter 7 prepared by you or under your supervision?

A. Yes, it was.

Q. Has the forecasting procedure used in preparing Part 1 of Chapter 7 been changed since Edison's last rate case?

A. Yes, it has.

Q. Please describe the nature of changes in Edison's forecasting procedure.

A. Previously, Edison used a "committee" approach to estimating kilowatthour sales and customers. The committee was comprised of representatives from the following organizations: Comptroller's; Conservation, Communications, and Revenue Services; Customer Service; System Development; Power Supply; and Treasurer's. Each committee member (except Power Supply) prepared forecast estimates which were averaged to develop the single estimate for each customer class.

Since February 1979, the responsibility of preparing kilowatt-hour sales and customer estimates was transferred to my department. We continue to utilize representatives from other departments as advisors to review the assumptions used in the forecast. However, the forecasts are now developed under my direction.

Q. Please explain generally how the kilowatthour sales estimates were made for 1979, 1980, and 1981, as presented in Table 7-A in Part 1 of Chapter 7.

A. Econometric models are used to develop initial kilowatthour sales estimates for the residential, commercial, industrial, other public authority, and resale customer classes, based on historical regressions. These estimates are adjusted based on judgment, short-term economic trends, and expected conservation impacts. Agricultural sales are estimated to remain constant except for the impact of conservation programs and are based on average precipitation conditions.

Estimated sales for the State Water Project (SWP) are based on the State Department of Water Resources' estimate of power required from the California suppliers to pump water through the California aqueduct and represent Edison's estimated share of such supply obligation. Metropolitan Water District (MWD) and Resale - Special Contracts' expected kilowatthour sales are based on forecasts by the customer or firm contracts.

Q. Please describe the econometric model used in preparing the kilowatt-hour sales estimates.

A. Electricity sales for each customer class are forecast as a function of electricity price, natural gas price, previous year's sales, and an economic variable (personal income or gross state product). These variables are adjusted for the effect of inflation - that is, all economic variables are in "constant" dollars. The regression equations are developed from a historical data base starting in 1951.

Q. How do you take conservation into account in your forecast?

A. The impact of conservation can be grouped into several categories. First is voluntary conservation, including "price-induced" conservation which represents our customers' responses to changes in electricity prices. Also included are other customer actions which take place due to customers' own initiative or in response to advertising and other utility conservation programs. The impact of such conservation is accounted for directly in our forecast through the price variable.

Second is the impact of conservation programs on Edison's side of the meter, such as conservation voltage regulation (CVR) and streetlight conversion. The impact of these efforts is estimated empirically and incorporated in the forecast.

Third is the impact of conservation programs mandated by regulations, such as appliance efficiency standards, building insulation standards, etc. The impact of these programs on sales is based on estimates of new applicances and buildings and the impact of standards on usage per appliance or per square foot of building space. The forecast sales are adjusted to reflect the impact of the mandatory conservation programs.

Q. How does recorded sales history impact your forecast?

A. We monitor recorded kilowatthour sales and transmitted data closely to identify factors which may influence future sales. Due to billing lags, transmitted kilowatthour data provides a five-to-six week forward look at expected kilowatthour sales. This allows us to reflect the impact of short-term trends on the forecast of kilowatthour sales. This is important because econometric models forecast changes in future activity on the basis of long-term historical correlations and do not always reflect short-term perturbations.

Q. How do you develop forecasts of economic variables used for the kilowatthour sales estimates presented in Part 1, Chapter 7?

A. We use the Data Resources, Inc. (DRI), economic forecasts for the nation and the University of California, Los Angeles (UCLA), model of the California economy to develop the economic inputs for the forecast. These estimates of economic activity are adjusted, if necessary, to account for unique economic and population trends in the Edison service territory.

Electricity prices are based on rates adjusted for expected changes in fuel costs and the rate base due to changes in generation, transmission, and other facilities. Natural gas prices are based on the latest available projections. Electricity and gas prices used in the forecasting model are in terms of "constant" dollars.

Q. What types of customers are included in the classification designated as "Other Public Authorities"?

A. Included in this classification are military establishments; public schools; federal, state, county, and city governmental offices; and street and public highway lighting.

Q. Would you briefly explain the basis for the estimates for the increase in the number of customers for 1979, 1980, and 1981, as shown on Table 7-A?

A. We estimate the total increase in customers on the basis of building activity, past and present trends of customer growth, in-migration into the service territory, economic conditions, and any other appropriate factors.

In 1978, our customers increased by 85,689 on the strength of a high level of building construction. Construction permits started to turn down in August of 1978. We are forecasting customer increases of 81,000 for 1979, 76,000 for 1980, and 76,000 for 1981, reflecting the construction slowdown.

Q. Are the system load estimates used to develop Power Production Expenses in Chapter 8 based on the kilowatthour sales forecast?

A. Yes, they are.

Q. Please describe how system loads are estimated.

A. System loads are equal to forecast sales plus estimated losses.

Q. Mr. Whyte, insofar as the material presented in Part I of Chapter 7 of Exhibit No. (SCE-2)______ is of a factual nature, do you believe it to be correct?

A. I do.

Q. Insofar as it represents opinion, does it reflect your best judgment?

A. It does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Warren E. Ferguson

Exhibit No. (SCE-2)______, Chapter 7, Parts II & III

Q. Please state your full name and address for the record.

A. My name is Warren E. Ferguson. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company, Mr. Ferguson?

A. I am Manager of Tariffs in the Revenue Requirements Department.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Warren E. Ferguson", does that portion of the exhibit accurately set forth your background, training, and experience?

A. It does.

Q. Are you testifying with respect to Chapter 7 of Exhibit No. (SCE-2)______ for identification in this proceeding?

A. Yes, for Parts II & III of Chapter 7.

Q. Were these parts of Chapter 7 prepared by you or under your supervision?

A. Yes, they were.

Q. What does Part II of Chapter 7 cover?

A. It covers the translation of the kilowatthour sales forecast by revenue class, shown in Part I, to customer group.

Q. What is the basis for the translation?

A. Based upon our historical data, the kilowatthour sales, by revenue class, are spread to rate schedules. The sales are then further adjusted by known or anticipated transfers of customers either between rate schedules or to rate schedules which were effective at the time of preparation of this filing for which little or no historical data is available.

Q. Could you explain that a little further?

A. For example, we have had some 500 customers during the first six months of 1979 transfer from Rate Schedule No. A-7 to Rate Schedule No. GS-2. These are primarily low load factor customers who benefit from the lower demand charges of the latter schedule. Because the transfers are so recent, our historical data does not fully reflect this transition. Similarly, Schedule No. TOU-8 became effective for customers with demands between 1,000 kW and 5,000 kW at about the time the filing was being prepared. As a result, we were aware that customers would be transferred from Schedules Nos. A-7 and PA-2 to Schedule No. TOU-8. Obviously, the historical data for these schedules does not reflect these changes.

Q. What does Part III of Chapter 7 cover?

A. It covers revenues derived from the sale of electric energy and from such other sources as rental of electric properties, transmission charges for redelivery of energy, and other miscellaneous services to our customers. In this part of the chapter are presented the recorded operating revenues by rate schedule and customer group for 1976, 1977, and 1978, as well as the estimated operating revenues for 1979, 1980, and 1981.

Q. Please explain how the revenue estimates were made for the years 1979, 1980, and 1981 for Chapter 7.

A. Again, based upon our historical data, the kilowatthour sales, kilowatt-months, and horsepower-years by rate schedule are spread to the various billing blocks. Base rate revenues are then calculated at the presently effective base tariffs. In addition, revenue was also computed based upon Edison's currently effective Energy Cost Adjustment Clause, with future billing factors based upon estimated fuel and purchased power expenses. The revenues were then further adjusted to reflect changes as a result of the operation of the balancing account contained in the Energy Cost Adjustment Clause. The revenues derived in this manner were then combined to produce total revenues by customer group.

Q. Table 7-H, also shows kilowatt-months and horsepower-years. What is the purpose of that estimate?

A. In order to develop revenues for rate schedules with demand or connected load charges, it is necessary to estimate kilowatt-months and horsepower-years. Historically, although the Company has always done this in preparing revenue estimates, it has never been shown in the forecast, and the Commission has always adopted only a kilowatthour sales estimate in its decision. Since a substantial portion of the Company's base rate revenue is now derived from such charges, I believe it is appropriate for these estimates to be included in the table, and I would urge the Commission in its decision to not only adopt a kilowatthour sales estimate but also a kilowatt-month and horsepower-year estimate where appropriate.

Q. Would you please explain briefly what types of accounts are comprised in the "Other Operating Revenue" classification?

A. "Other Operating Revenue" consists of revenues received by the Company for other than sales of electric energy. These would include, for example, revenues from the service establishment charge, reconnection charges, and special contractual agreements involving the transmission of energy for others under various transmission service agreements. Revenue in this classification is also realized from meter and transformer rentals, special contract rentals, joint pole and property rentals, the installation of additional facilities to customers under added facilities agreements, and other miscellaneous services.

Q. Mr. Ferguson, insofar as the material presented in Parts II and III, Chapter 7 of Exhibit No. (SCE-2)______ is of a factual nature, do you believe it to be correct?

A. I do.

Q. Insofar as t represents opinion, does it reflect your best judgment?

A. It does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Ronald V. Knapp

Exhibit No. (SCE-2)_____, Chapter 8

Q. Please state your name and address for the record.

A. Ronald V. Knapp. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company?

A. Manager of System Operation in the Power Supply Department.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Ronald V. Knapp", does that portion of the exhibit accurately set forth your background, training, and experience?

A. Yes, it does.

Q. Mr. Knapp, what portion of the Southern California Edison Company's Results of Operations exhibit are you sponsoring?

A. I am sponsoring Chapter 8, Power Production Expenses. I am also sponsoring Chapter 9, Transmission Expenses.

Q. Please indicate briefly what Section A of Chapter 8 covers.

A. Section A of Chapter 8, titled "System Loads and Resources, Fuel, and Purchased Power", includes fuel and purchased power expenses, recorded and adjusted to average-year conditions for 1976, 1977, 1978, and the first nine months of 1979. The remainder of 1979 and years 1980 and 1981 reflect estimated average-year conditions.

Q. Since fuel and purchased power expenses are covered by the energy cost adjustment clause (ECAC), why are they being included in the general rate case?

A. Since some elements of the base rate cost of service (e.g., working capital) are influenced by the full cost of service, it is appropriate to estimate the full cost of service in the test year. In addition, I am advised that the effect of domestic lifeline rates on customer group rate of return only becomes evident by studying the rate of return by customer group under full cost of service analysis. The fuel and purchased power expenses must, therefore, necessarily be considered in this proceeding along with all other costs.

Q. Where in this exhibit are net fuel and purchased power expenses shown after removal of ECAC related expenses?

A. Line 38 on Table 8-A reflects the net fuel and purchased power expenses without ECAC. Calculation of ECAC related expense appears in footnotes at the bottom of Tables 7-C in Chapter 7.

Q. Having in mind the fact that energy produced from oil fuel is the most costly among the resources available to the Company, what methodology is reflected in your estimates that results in minimizing use of this source of energy?

A. The basic tool that is used for determining the oil/gas unit energy requirement is a computer program that simulates the integration of Edison's resources to meet the projected load. Beginning with the load forecast, the program deducts energy that is estimated to be available from resources other than oil/gas such as hydro, nuclear, coal and purchased power. Whatever load requirement remains must be served by energy supplied by Edison's oil/gas units. By providing the program with average-year gas availability data, the amount of energy expected to be generated on gas fuel is deducted from the remaining load requirement. Any residual load is assumed to be served by units burning oil fuel.

Q. Considering the favorable price of purchased power in relation to energy derived from oil fuel, what effort is made to maximize energy purchases?

A. The Company has an entire division whose major responsibility is to negotiate long- and short-term contracts with utilities throughout the western United States and Canada. In order to make these contracts work, we have an aggressive power scheduling or "power broker" section devoted to obtaining and scheduling any economical energy which is made available by utilities on a day-before basis. In addition, on a real-time basis, our Energy Control Center Dispatchers maintain a regular search for economical hourly spot purchases to fill any remaining transmission line capacity.

In 1978, for example, we were successful in procuring energy purchases amounting to about 17 percent of the Company's total energy requirement, representing a savings of almost 18 million barrels of fuel oil. Of course, hydrological conditions in the northwest play a significant part in the availability of purchased power, and 1978 was a better-than-average year in this regard.

Q. Referring to Table 8-A, please indicate the volumes of fossil fuels expected to be burned and discuss the price trend for these fuels from 1979 through 1981.

A. Our gas suppliers have estimated that average-year gas availability will decrease in future years resulting in greater dependence on oil fuel. Approximately 21 million equivalent barrels of natural gas fuel are estimated to be available in 1979, 15 million equivalent barrels in 1980, and 11 million equivalent barrels in 1981. Due to inflation and gas deregulation, the average gas price is estimated to increase from \$2.41 per million Btu in 1979, to \$3.35 per million Btu in 1980, and to \$4.02 per million Btu in 1981.

Edison's share of coal consumption at Mohave and Four Corners in 1979, 1980, and 1981 is estimated to be 12, 15, and 15 million equivalent barrels, respectively. Average coal prices are estimated to increase from $0.68 per million Btu in 1979 to $0.70 and $0.79 per million Btu in 1980 and 1981. These estimates are based on the assumption that mining, transportation, and labor costs will continue an upward trend.

Oil fuel consumption in 1979, 1980, and 1981 is estimated to be about 49, 56, and 61 million barrels, respectively, assuming average-year conditions. Average oil price estimates are influenced by recent OPEC price increases and reflect domestic oil price decontrol. For the three years, 1979 through 1981, average projected prices are about $20/barrel, $30/barrel, and $36/barrel, respectively.

Q. Looking now at nuclear production, what is the energy cost in the estimated years, and what do the expenses for San Onofre Unit 2 represent?

A. The fuel expense component of energy generated at S. Onofre Unit 1 is estimated to average about 4.8 mills/kWh in 1979, 6.3 mills/kWh in 1980, and 6.9 mills/kWh in 1981. These expenses are very favorable when compared with projected oil-fueled unit energy costs of 32 mills/kWh in 1979, 48 mills/kWh in 1980, and 58 mills/kWh in 1981.

San Onofre Unit 2 is expected to be in a start-up and power escalation phase from March 1 through June 30, 1981. Edison's share of pre-release energy ger rated during this period is estimated to be about 506 GWh and is inclu n purchased power at an average oil-fueled unit energy cost of 47 mills This expense will become a credit to the Work Order.

Beginning July 1, 1981, San Onofre Unit 2 is included in Thermal Station Expense, and energy is priced at about 12 mills/kWh.

Q. With respect to purchased power, what is the basis for economy and surplus energy purchases, and what is the expected price in 1979, 1980, and 1981?

A. Economy and surplus energy is purchased on a when-an-if-available basis.

The average-year economy and surplus estimates are derived from an average of sixty months of recorded purchases through the end of 1978.

The price of economy energy is expected to average about 16.5 mills/kWh in 1979 and is estimated to increase approximately in proportion to the price of oil-fueled generation. Accordingly, estimates of 16.5, 18.5, and 21 mills/kWh were used for economy energy in 1979, 1980, and 1981, respectively.

Surplus energy is currently priced at 3.5 mills/kWh in the winter months and 3 mills/kWh in the summer months. These rates are subject to revision effective December 20, 1979, but since it is not known to what extent the rate will be changed, surplus energy in 1979, 1980, and 1981 is priced at the current rates.

Q. Turning to Section B of Chapter 8, please indicate briefly what the section reflects.

A. This section includes the Operation and Maintenance Expenses (Production - Excluding Fuel) for Steam, Hydro, Nuclear, and Other types of generation, summarized in Table 8-B for 1976-1978 recorded, and 1979, 1980, and 1981 estimated.

Q. How were the estimates for future years 1979, 1980, and 1981 developed?

A. We used a trending method.

Q. Mr. Knapp, please describe the methodology used to determine the trended estimates.

A. The estimated Production Expense for the future years 1979, 1980, and 1981 was derived by trending historical data for the recorded years 1974 through 1978. Adjustments were made to each account's historical costs for 1974 through 1978 to remove the effects of unusual conditions that would affect the recorded year's usefulness for trending purposes. After the recorded years were adjusted, the recorded costs for 1974 through 1978 were indexed to 1978 dollars. This was the starting point for the future year estimates. The adjusted-recorded figures were then trended for estimates for three future years (1979-1981). A least squares linear trend method was used. The future year estimates were developed, and each year was then escalated 7% for labor and 9-1/2% for non-labor. Adjustments were made to the escalated estimate for certain accounts by adding known significant activities that were considered new or expanded and for which costs would not be provided by a trending method.

Q. How did you determine the escalation factors that were used to index the recorded years to 1978 monies and the future year escalation factors for 1979, 1980, and 1981?

A. Escalation rates for Operation and Maintenance accounts for Production were developed by our Economics Division based on economic assumptions and forecasts made by Data Resources, Inc. These escalation factors were then converted to 1978 constant dollar inflator/deflator indices, for the period 1974 through 1981, by our Revenue Requirements Department.

Q. Was this method of estimating used for Steam, Nuclear, Hydraulic, and Other Power Generation Accounts?

A. Yes, with minor exception. In determining the future year estimates for the Hydraulic Power accounts, it was decided to use a 9% escalation factor for non-labor estimates rather than the 9-1/2% used for Steam, Nuclear, and Other Production.

Q. Why?

A. This was a judgment decision. In reviewing the ratio of material to contract work and the types and cost of materials used in Hydraulic Production, it was determined that the escalation factor for non-labor for Hydraulic expense should be 9%.

Q. Mr. Knapp, have any specific programs been initiated to reduce production, operation, and maintenance expenses?

A. Edison has implemented many programs to increase productivity and reduce operation and maintenance expenses. Our efforts have been and will be directed specifically toward increasing generating unit availability and capacity, increasing reliability of our operating equipment, reducing operating costs, and improving manpower productivity.

Q. Will you please tell us what specific programs have been undertaken to improve productivity?

A. In the production, operation, and maintenance areas, a comprehensive maintenance management system is being developed. The primary objective of this system is to improve unit reliability. Also, as part of our program to reduce costs, an automated material inventory control system is in the development stage. The system will provide better visibility and control of maintenance material and parts usage, thus reducing excess redundant stock and reduce stock shortages. In the area of cost reduction, we have recently implemented a 7-day work week at our Mohave Generating Station. Under this arrangement, it is expected that labor costs will be reduced as a result of reduced payment of overtime. Other programs being implemented include integrating major maintenance and overhaul activities at different production locations, expanding our capability of performing repair work of major equipment, and more closely controlling work performed by contractors.

Our management is and has been dedicated toward improving productivity and controlling costs. We plan to continue to seek areas of improvement to reduce costs and improve productivity. To assist us in this endeavor, we have obtained the services of an outside consultant and the services of our Company's Internal Audits Productivity Measurement Organization.

Q. Will you please tell us specifically how these savings were included in your estimates?

A. Edison management has been and will continue to be committed to increasing productivity. This concept is not new to us. Our estimates have been developed based on a trending method, and since our recorded data implicitly considers productivity improvement, no specific adjustments were required.

Q. Mr. Knapp, in preparing the estimates for Production, did you have to make adjustments to each account prior to developing the trended estimates?

A. No. Accounts that did not have significant high or low yearly expenditures and did not distort the future year trend were not adjusted.

Q. Were adjustments required for Accounts 500, Operation supervision and engineering, and 505, Electric expenses?

A. No. The over-all projection of the trend presents a realistic reflection of expected expenditures to these accounts for the future years.

Q. Please explain what major adjustments were required for the other Steam Power Production accounts.

A. The balance of the other accounts in Power Production required adjusting before trending could begin. Probably the most significant adjustment was related to major unit planned overhauls. Overhauls expenditures vary between years with the level of overhaul activity, such as the number of unit overhauls, the size of the generating units, and the work activity required to accomplish the overhaul work. As an example, 10 major unit overhauls were accomplished in 1974, 4 in 1975, 8 in 1976, 15 in 1977, and 14 in 1978. There are 7 major unit overhauls planned for 1979, 11 in 1980, and 7 in 1981. This includes overhauls for Steam, Other, and Nuclear Production. To develop an estimating trend for normal operation and maintenance activities, it was necessary to remove the overhaul costs from the recorded years before trending and add in the costs for overhauls planned for 1979, 1980, and 1981 as adjustments to the figures developed by trending. Another major adjustment pertains to unforeseen maintenance expense associated with overhaul expenditures. As previously discussed above, trended estimates are based on recorded expenditures, less recorded major overhaul expenditures, while future year adjustments for major unit overhaul are based on field estimates, which do not include any amount for repairs determined necessary at the time of overhaul accomplishment. Analysis of major unit overhauls historical budgeted versus actual expenditures for the years 1976 through 1979 disclosed that unforeseen work averaged $522,400 per major unit overhaul for this period. Based on a linear trend of the average overrun cost per major unit overhaul for the years 1976 through 1979, the unforeseen maintenance expenditures for the estimated years 1979, 1980, and 1981 are $5,172,300, $6,101,100, and $4,684,800, respectively. As such, this estimate was allocated to accounts 506, 510, 511, 512, 513, and 514 based on a percentage of each account's adjustment for expenses associated with generating unit overhauls.

Account 502, Steam expenses, required two adjustments. The most significant was the removal of air quality regulatory requirements costs from the recorded years 1974-1978 before trending and the inclusion of these costs in the estimated years 1979-1981 as adjustments to the trended figures. Costs for air quality monitoring studies, investigation, operation of equipment, etc., to comply with and/or contest regulatory agency requirements and ordinances have varied in the recorded years and are increasing in the future years due to additional requirements. In mid-1978, the South Coast Air Quality Management District permit renewal fees increased significantly, and additional fees have been levied for emissions. Emission abatement orders 2008 and 2012 have been received from the South

Coast Air Quality Management District and will require significant expenditures to achieve compliance by September 1981. The following costs were removed from the recorded years: 1974 - $887,000, 1975 - $720,000, 1976 - $1,119,000, 1977 - $1,114,000, and 1978 - $1,533,000. The following costs were added to the estimated years: 1979 was $3,340,000, 1980 - $3,788,000, and 1981 - $3,598,000. Additional adjustments were made to the years 1974, 1975, and 1976 to remove significant water chemical treatment costs which are no longer required at our Mohave Generating Station.

Account 506, Miscellaneous steam power expenses, is mostly comprised of Research and Development costs. These costs vary significantly from year to year based on programs undertaken. Therefore, they were removed from the recorded years 1974-1978 before trending, and estimated amounts were added to the trended figures for future years 1979-1981 based on current corporate Research and Development programs. In the recorded years, $10,177,000 was removed from 1974, $2,280,000 from 1975, $2,137,000 from 1976, $1,862,000 from 1977, and $4,222,000 from 1978. To account for current corporate Research and Development programs, $5,420,000 was added to the 1979 figure developed by trending, $3,538,000 to 1980, and $3,909,000 to 1981. Another significant adjustment to Account 506 relates to expenditures for water quality monitoring studies, investigations, permits, fees, etc., to comply with and/or contest regulatory requirements related to Steam Production. These costs have varied in the recorded years and are projected to be significantly higher in the estimated years and, therefore, were removed from the trend. In 1975, $264,000 for water quality control and monitoring was removed, $457,000 in 1976, $335,000 in 1977, and $740,000 in 1978. For the years 1979, 1980, and 1981, $2,435,000, $1,770,000, and $830,000, respectively, was added to the trended estimates to cover the costs for compliance with current predictions of high activity in 1979-1981 to comply with the requirements of Federal Water Quality Control Act 316.b., pertaining to the discharge of cooling water into the ocean. In addition to these adjustments, other adjustments were made to recorded and estimated years to cover expenditures associated with generating unit overhauls, as previously discussed, refurbishment of the Long Beach Generating Station Units 10 and 11, and the Standards and Performance Study directed by the CPUC for Mohave and Four Corners Generating Units.

Account 507, Rents, was neither indexed to 1978 monies nor escalation applied as most Rents are firm contracts. Therefore, firm costs were used for the future years 1979, 1980, and 1981.

Account 510, Maintenance supervision and engineering. The major adjustment to this account is associated with overhaul cost at various generating stations - $319,000 was removed in 1974, $153,000 in 1975, $315,000 in 1976, $713,000 in 1977, and $524,000 in 1978. For the future years, $588,000 was added to 1979, $988,000 to 1980, and $495,000 to 1981. A small adjustment was made to correct an accounting error in the years 1977 and 1978. Monies were added to the future years' trend for 1980-1981 in the amount of $90,000 and $112,000, respectively, for the computerized maintenance planning program. This will be implemented for the purpose of achieving a more over-all effective maintenance and improve generating units and equipment reliability.

Account 511, Maintenance of structures. Adjustments were made to remove the cost of repairs to a bridged inactive coal storage pond in 1975, repairs to the lining of two water ponds in 1976, and repairs to the asphalt surfaces in 1975, 1976, and 1978 at the Mohave Generating Station. Minor adjustments were made to this account removing overhaul expenditures in the recorded years and adding overhaul costs to the future years.

The cost for the refurbishment of Long Beach Generating Station Units 10 and 11 was removed from the years 1976, 1977, and 1978. In 1981, $1,195,000 was added for the repair of the plant drainage system, including asphalt surfaces and for the cleaning and repair of the linings of two large water ponds at Mohave Generating Station.

Account 512, Maintenance of boiler plant, has significant adjustments for overhaul costs. The adjustments from the recorded years are $2,492,000 in 1974, $2,223,000 in 1975, $4,539,000 in 1976, $9,046,000 in 1977, and $8,483,000 in 1978. Future-year overhaul costs in the amount of $4,721,000 were added to 1979, $5,799,000 in 1980, and $6,878,000 in 1981. Also in 1981, significant maintenance expenditures amounting to $3,691,000 will be required at the Mohave Generating Station. This includes major boiler plant equipment repairs to improve capacity factors of coal plant production. Some examples of the activities are; reheat tube replacement, primary air ducts replacement, air preheater baskets, and super heater tube replacement. It is necessary to replace boiler air-preheater elements to maintain thermal efficiencies, as well as preventing particulate fallout due to existing fuel gases in various generators. These expenditures vary from year to year and, therefore, have been adjusted out of the recorded years. Expenditures for 1979-1981 have been provided for in the future estimates. Air-preheater heating elements replacement costs in the amount of $906,000 were removed from recorded year 1974, $613,000 in 1975, $1,864,000 in 1976, $1,652,000 in 1977, $903,000 in 1978. Known future-year air-preheater element replacements in the amount of $2,884,000 were added to 1979, $1,548,000 to 1980, and $1,204,000 to 1981. These were the major adjustments that were made to Account 512. Other adjustments were made for the refurbishment of Long Beach Generating Station Units 10 and 11 for the years 1977-1979, and costs for boiler plant O&M expenditures in 1980 and 1981 in the amount of $6,939,000 and $1,900,000, respectively, to comply with emission abatement orders.

Part of the revenue received from contract energy sales to other utilities is a cost factor for operation and maintenance. Therefore, that part of the revenue received for contract energy sales to other utilities that relates to O&M costs was adjusted out of the recorded year expenditures. Half of these costs were adjusted out of Account 512 and the other half out of Account 513.

Again, in Account 513, Maintenance of electric plant, the most significant adjustment relates to overhaul expenditures - $3,523,000 was adjusted from the year 1974, $2,510,000 from 1975, $5,199,000 from 1976 $10,371,000 from 1977, and $11,301,000 from 1978. Future-year estimated overhaul costs in the amount of $8,264,000 were added to 1979, $8,048,000 to 1980, and $7,782,000 to 1981. Another significant adjustment was made to this account for the removal of significant cost activities from the recorde ars that are considered to be non-routine type of maintenance and the recurrence of same would not be expected each year. Some of these maintenance activities are extensive cooling tower repairs, purchase and replacement of steam turbine blading and diaphrams, and the purchase of a high pressure steam turbine rotor. Considering the nature of these activities, $916,000 was removed from the year 1974, $1,612,000 was removed from the year 1976, $1,640,000 from 1977, and $1,922,000 from 1978. Future year estimated costs for these activities were added to the trend. $4,480,000 was added to 1979, $2,449,000 to 1980, and $2,080,000 to 1981. This amount includes $4,480,000 in 1979, $1,512,000 in 1980, and $1,120,000 in 1981 for condenser retubing required at Mohave Generating Station. Another adjustment was made to this account for the refurbishment of Long Beach Generating Station Units 10 and 11. Part of the revenue received from contract energy sales to other utilities is a cost factor for operation and maintenance. Therefore, that portion of the revenue received for contract energy sales to other utilities that relates to O&M costs was adjusted out of the recorded year expenditures. Half of these costs were adjusted out of Account 512 and the other half out of Account 513.

Account 514, Maintenance of miscellaneous steam plant, required four adjustments - the most significant being adjusting of property damage costs out of recorded years and adding the estimated property damage costs to the estimated years 1979, 1980, and 1981. Property damage costs have varied significantly in the past, and trending of these costs did not appear to be logical. Therefore, the recorded expenditures were removed in the recorded years 1974-1978, and the estimated amounts for property damage as determined by our Comptroller's Department were used for the future-year costs, 1979-1981. Relating to property damage, $2,853,000 was adjusted out in 1974, $1,300,000 in 1975, $1,048,000 in 1976, $3,646,000 in 1977, and $6,815,000 in 1978. The Comptroller's Department storm damage estimate for 1979 was $2,922,000, $3,127,000 for 1980, and $3,346,000 for 1981. These costs were added to the future years' estimate.

Q. Mr. Knapp, please comment on the significant adjustments that were required to develop a trend projection of expenditures for Other Power Generation Production for the future years 1979-1981.

A. The accounts in Other Power Generation Production did not require a great deal of adjustments. The major adjustments to Other Power Generation Production accounts revolved around any other production resources that had been placed in service during the December 31, 1976, through December 28, 1978, period. These added resources were the Long Beach Combined Cycle Units 8 and 9, the Coolwater Combined Cycle Units 3 and 4, and the Yuma Axis Gas Turbine Peaker. The expenditures to operate these new resource facilities are significant to the accounts for Other Power Generation Production and are not represented in the recorded years. Therefore, a reasonably accurate trend for the future estimated years 1979-1981 could not be developed until the expenditures relating to the new facilities were removed from the recorded years 1976, 1977, and 1978. The estimated expenditures for the new facilities were then added to the future years' trends 1979-1981 to provide realistic estimates. As I go through Other Production by account, I will detail the adjustments relative to the new facilities referred to.

In Account 546, Operating supervision and engineering, $15,000 was removed from 1976, $105,000 from 1977, and $205,000 from 1978; and $263,000 was added to 1979, $279,000 to 1980, and $306,000 to 1981 for the new Other Power Resource facilities.

Again in Account 548, Generation expenses, the only adjustment was in the Long Beach, Cool Water, and Yuma Axis facilities. In 1977, $556,000 was removed and $1,115,000 in 1978. In 1979, $1,389,000 was added, $1,585,000 in 1980, and $1,770,000 in 1981.

Account 549, Miscellaneous other power generation expenses, had two adjustments. One adjustment for the new facilities removed $3,000 from the year 1976, $579,000 from 1977, and $886,000 from 1978. In 1979, $625,000 was added, $651,000 in 1980, and $596,000 in 1981. The other adjustment is for Research and Development. As an example, R&D comprised nearly 45% of the total expenditures for this account in 1978. The projected expenditures for the years 1979, 1980, and 1981 will be more significant due to the current projects in various stages of Research and Development for other energy resources. The over-all level of R&D expenditures has varied annually and thus were removed from the recorded years, and the estimated costs of corporate R&D programs were added to the future years 1979-1981. For the recorded years, $375,000 was removed from 1974, $448,000 from 1975, $317,000 from 1976, $539,000 from 1977, and $782,000 from 1978. Future corporate R&D programs were added to the estimated years 1979, 1980, 1981 - $1,950,000, $4,069,000 and $3,940,000, respectively.

In Account 550, Rents, historic expenditures to this account were neither indexed nor escalated as there was relatively little history and because rents are contracted for firm amounts. Therefore, our projected rents for the future years are stated in contracted amounts.

Account 551, Maintenance supervision and engineering, was again adjusted to remove the expenditures for new facilities from the recorded years and provide for these facilities in the future years. These adjustments were the removal of $78,000 from 1977 and $114,000 from 1978 and the adding of $200,000 to 1979, $241,000 to 1980, and $253,000 to 1981. There was a minor adjustment in this account for overhaul expenditures.

Account 552, Maintenance of structures, was adjusted only for the new Long Beach, Cool Water, and Yuma Axis facilities. The year 1977 was reduced $32,000 and 1978 by $207,000, and the estimated years were increased by $160,000 for 1979, $202,000 for 1980, and $222,000 for 1981.

Account 553, Maintenance of generating and electric plant, contained three types of adjustments. A new facilities adjustment was made reducing $427,000 from 1977 and $1,338,000 from 1978 and adding $1,553,000 in 1979, $1,594,000 in 1980, and $1,688,000 in 1981. In 1980, replacement of four silencer stacks for the Mandalay Peaking Unit #3 is planned. The trended estimate does not reflect this major item of cost; therefore, $838,000 was added to the trended estimate for the year 1980. This account includes overhaul costs for peaking units and combined cycle units, and these overhaul costs have been treated similar to those in Steam Production accounts. Therefore, the over-all costs relative to the heretofore mentioned new facilities were removed from the recorded years and added to the estimated years. These adjustments were the removal of $133,000 from 1977 and $512,000 from 1978 and adding of $30,000 to 1979 and $124,000 to 1980.

Account 554, Maintenance of miscellaneous other power generation plant, was adjusted for new facilities and for property damage. In regards to the new facilities, the recorded costs were minimal, and no adjustments were made. The future years were adjusted by increasing the 1979 trend by $45,000, 1980 by $54,000, and 1981 by $59,000.

Expenditures for property damage relating to Other Production have historically been minimal due to the number and size of the Other Production facilities. New Other Production facilities placed into operation since 1976 are expected to moderately impact property damage expenditures. In 1978, a significant property damage expenditure was incurred primarily due to a fire at the Ellwood Energy Support Facility. This property damage expense amounted to 96% of the total 1978 expenditures to this account. Therefore, trending historical Property Damage and escalating expenditures does not provide a realistic projection of costs. Accordingly, expenditures in the recorded years 1976, 1977, and 1978 were removed, and estimated amounts determined by our Comptroller's Department were added to the estimated years 1979 through 1981 to more accurately reflect our resource requirements. These adjustments were: $1,000 removed in 1975, $1,000 in 1977, and $584,000 in 1978. The year 1979 was increased $25,000, 1980 by $26,000, and 1981 by $28,000.

Q. Would you now cover Hydraulic Production?

A. Yes. Four accounts in Hydraulic Production did not require adjustments as there are no unusually high or low expenditures in the recorded years or anticipated in the future years. The over-all projection of costs using the trend method appears satisfactory. These accounts are: 537, Hydraulic expenses; 538, Electric expenses; 539, Miscellaneous hydraulic power generation expenses; and 536, Water for power.

Q. Did you use the straight trending method for these accounts?

A. Yes.

Q. Please explain the adjustments for Hydraulic Production.

A. The adjustments in Hydraulic Production differ from the majority of Steam and Nuclear as they do not relate to significant scheduled overhead costs. Most of the adjustment in Hydraulic Production covers specific activities that were either abnormally high in one year or low in another year that had to be adjusted to normalize the recorded years. Future years' estimates were increased to provide for significant planned items that would not be accounted for by a straight trending method.

In Account 535, Operation supervision and engineering, the only adjustment made was to future-year estimates 1979-1981. In 1979, two additional Control Station dispatcher positions were added to Bishop operations. Therefore, the estimated years were adjusted to reflect the addition of these two positions. As such, 1979 was increased $38,000; in 1980, $46,000; in 1981, $50,000.

In Account 540, Rents, two adjustments were made. The recorded year 1975 also included the 1974 rental payments. Therefore, $75,000 was adjusted out of 1975 into 1974. The other adjustment was to account for timber sales in 1976 of $53,000 and in 1978 of $14,000. To properly reflect the 1976 and 1978 recorded expenditures, these years were increased by the amount of the timber sales to provide a more normal basis of recorded expenditures and a realistic trend for expected expenditures.

Account 541, Maintenance supervision and engineering, was adjusted to remove unusual expenditures in recorded years that were not planned to be repeated in the future years - $51,000 was removed in 1974 and $41,000 in 1976 to cover the cost to prepare inundation maps as required by the State of California, Office of Emergency Services. The year 1976 was also adjusted by removing $30,000 from the recorded costs for a seismic stability study on Vermillion Dam to meet the requirements of the California Division of Dam Safety. These adjustments to recorded figures helped to provide a realistic trend.

One adjustment was made to Account 542, Maintenance of structures. The 1978 recorded expenditures were abnormally high for this activity. This was the result of extra maintenance performed to structures due to a shift from other work activities. The year 1978 being a high water year prevented normal maintenance activities from being performed on dams, reservoirs, etc. To normalize the effect of the above-average work activities in this account, $50,000 was removed from the 1978 recorded costs. This normalization was required to provide a more accurate trend for estimating expenditures in future years 1979-1981.

Account 543, Maintenance of reservoirs, dams, and waterways, required several adjustments to normalize the recorded expenditures. In 1976, $118,000 was removed from the recorded costs and $215,000 in 1977. These costs represent significant repair work that was performed at Kaweah No. 2 and at the Rush Meadows Dam. These years were adjusted to more closely reflect normal maintenance expenditures in this account. Recorded 1978 was also increased $160,000. This was done to compensate for a below normal maintenance activity level in 1978 which was caused by an unusually high water year. High water conditions, caused by heavy rain and snow, prevented normal maintenance from being performed on activities in this account. Maintenance activities normally performed on equipment in this account were directed to other work activities that were not affected by the high water condition. Therefore, it was necessary to adjust 1978 to reflect a more normal year's expenditure. The estimated 1979-1981 years were adjusted to include significant planned maintenance activities for which costs would not be provided in the trend method. The year 1979 was increased $337,000 for repairs to the Kaweah No. 2 canal lining and flumes, repairs to Chinquapin and Camp 62 diversion pipeline repair intake structures and grids at Big Creek No. 3, repair the gunite seals on Dams 1 and 2 at Huntington Lake, and coating the exterior of Kaweah No. 1 flume. The year 1980 was increased by $75,000 to provide for guniting the down-stream face of Kern River No. 1 Intake Diversion Dam. The year 1981 was increased by $125,000 for repair work for Kern River No. 1 Intake.

Account 544, Maintenance of electric plant, also was adjusted to account for specific maintenance activities in recorded years and to provide for specific maintenance activities in the future years. The amount of $260,000 was removed from the 1974 recorded costs for the replacement of Big Creek No. 4 Unit 2 Generator Winding, $334,000 was removed in 1976 for replacement of Big Creek No. 4 Unit 1 Generator Winding, and the rewinding of Unit 3 at Kern River No. 1. The year 1977 was adjusted by $215,000 for rebabbitting five main generator bearings and purchase of replacement unit windings at Big Creek No. 3. As a result of 1978 being a high water year, caused by heavy rains and snow, normal maintenance work could not be accomplished during the year on this account. To compensate for this, $40,000 was added to this account to normalize the 1978 expenditures. Offsetting this increase, another adjustment decreasing this account by $157,000 was made. This adjustment was due to a significant maintenance work item involving the installation of No. 2 Unit winding at Big Creek 3. The net effect of these two adjustments was a net credit adjustment of $117,000 to 1978. The estimated years 1979 and 1980 were also adjusted for significant planned maintenance items. The year 1979 was increased by $282,000 for installation of Units Nos. 1 and 3 generator windings at Big Creek 3, and 1980 was increased $173,000 for Unit No. 2 generator winding installation at Big Creek 3.

Account 545, Maintenance of miscellaneous hydraulic plant, had two adjustments. The recorded 1974 year was reduced $102,000, which was the cost to perform maintenance work on hydro cranes due to OSHA requirements. The other adjustment was for property damage. The over-all level of property damage expenditures has varied yearly; thus property damage costs were not trended. Recorded property damage costs were removed from the recorded years, and estimates of property damage, as determined by our Comptroller's Department, were used for the future years 1979-1981.

Q. Mr. Knapp, what adjustments were required in the Nuclear Production accounts?

A. The most significant adjustments involved overhaul and refueling costs. The same methodology was used to adjust for these costs as previously explained in Steam Production. Other adjustments were made to normalize the recorded years 1974-1978, and adjustments were made to the estimated years 1979-1981 figures developed by trending to include costs for significant activities that would not be provided for in the trending procedure.

Account 517, Operation supervision and engineering, was adjusted in 1976 to remove $5,000 from the recorded year for overhaul and refueling costs. Overhaul costs in the other recorded years and future years in this account were considered minimal, and no further adjustments were made.

No adjustments were made to Account 519, Coolants and water, and Account 523, Electric expenses.

Account 520, Steam expenses, was adjusted for overhaul and refueling costs. The year 1975 was reduced $157,000, 1976 by $258,000, and 1978 by $171,000. The year 1980 was increased by $409,000 and 1981 by $419,000.

Account 524, Miscellaneous nuclear power expenses, was adjusted for overhaul and refueling costs and for Research and Development. The years 1975, 1976, and 1978 were reduced $37,000, $73,000, and $42,000 respectively, for overhaul and refueling costs, and 1980 was increased $136,000 and 1981 by $75,000. R&D was adjusted the same as in Other Production accounts. Recorded R&D costs were removed from the trend period and added to the future-year trend in the amounts predicted for future R&D corporate programs. The estimated years 1979, 1980, and 1981 were increased by $25,000, $100,000, and $100,000, respectively, for costs relating to the Institute of Nuclear Power Operations (INPO). Since the Pennsylvania accident, the nuclear indistry has established the Institute of Nuclear Power Operations (INPO), a privately funded organization. The purpose of INPO is to set criteria and monitor the industry's safety related goals. Also, INPO will provide enhanced training for reactor operators and bench marks for excellence in nuclear power operations throughout the industry. Also, adjustments were made to the estimated years 1979 thru 1981 for costs relating to Senate Bill 1183, Chapter 956, pertaining to appropriations for state governmental agencies to declare and investigate emergencies and to establish plans for responding to emergencies. For the year 1979, $25,000 was provided; 1980, $250,000; and 1981, $250,000.

Account 525, Rents, was not trended. Firm contract costs were used in the estimated years 1979-1981.

Account 528, Maintenance supervision and engineering, was adjusted for overhaul and refueling costs. The year 1975 was reduced

$83,000; 1976, $163,000; 1977, $36,000; and 1978, $140,000. The future years 1980 and 1981 were increased $86,000 and $98,000, respectively, for overhaul and refueling costs.

Account 529, Maintenance of structures, had only minimal adjustments to 1975 and 1976 for overhaul costs, $11,000 in 1975, and $8,000 in 1976.

Account 530, Maintenance of reactor plant equipment, was adjusted for overhaul and refueling costs plus an accounting correction in 1975 amounting to $484,000. The year 1975 was reduced $568,000, 1976 by $632,000, 1977 by $1,297,000, and 1978 by $1,118,000 for overhaul and fueling costs. Costs were also provided in 1979, 1980, and 1981 in the amount of $966,000, $1,572,000, and $339,000, respectively, for overhaul and refueling activities.

Account 531, Maintenance of electric plant, was adjusted for overhaul and refueling costs. Overhaul and refueling adjustments were made by reducing 1975 by $706,000, 1976 by $143,000, 1977 by $100,000, and 1978 by $251,000. The 1979 and 1980 trend was increased by $11,000 and $734,000, respectively, and 1981, $523,000. Also, the recorded year 1974 was adjusted by $484,000 for an accounting correction, and in 1975, a non-routine expense for the retubing of the main cooling water condenser was removed from the respective recorded year.

Account 532, Maintenance of miscellaneous nuclear plant, was adjusted for overhauls and refueling and for property damage. Relative to the overhaul and refueling costs, 1975 was reduced by $22,000, 1976 by $18,000, 1977 by $1,000, and 1978 by $15,000. In 1980, $15,000 was added to the trend estimate and $14,000 in 1981. Trending historical property damage costs and then escalating does not provide a realistic trend. Accordingly, recorded property damage expenditures were removed from the trending base years, and the estimates determined by our Comptroller's

Department were used to more accurately reflect the resource requirements in the future years.

Q. Does that conclude your adjustments to Nuclear accounts?

A. Yes.

Q. Mr. Knapp, do you believe the trending methodology, with adjustments, that you used to determine the operating and maintenance costs for 1979, 1980, and 1981 to be a realistic projection of the future resource requirements for Power Production work activities?

A. Yes. I do. It is my judgment that the trending methodology used provides a projection of the future resource requirements for Power Production work activities for the period under study, which likely is conservative and on the low side.

It is my opinion that the level of maintenance for existing facilities will increase slightly above the trended figures during the next few years. This opinion is based on two factors: (1) the increasing age of our facilities which requires increased maintenance to continue the reliability of the equipment at an acceptable level, and (2) the impact on which the reduction in capacity margins will have an increasing facilities utilization and the attendant increase in maintenance. This later factor is anticipated to be most noticeable during the next three years since only one small unit of capacity increase is planned between now and 1981. In the absence of specific data to project these factors, however, the trending method used appears to provide the most realistic approach at this time.

Q. Insofar as the material in Chapter 8 is of a factual nature, do you believe it to be accurate?

A. Yes, I do.

Q. Insofar as the material in Chapter 8 represents opinion, does it represent your best judgment?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Ronald V. Knapp

(Exhibit No. (SCE-2)_____, Chapter 9)

Q. Mr. Knapp, you previously indicated that you are sponsoring Chapter 9 of Exhibit No. (SCE-2)_____. Is that correct?

A. Yes.

Q. Briefly, what does this chapter cover?

A. This chapter covers the expenses for operating and maintaining the Company's transmission system. These costs include labor, material, and other expenses for transmission substations, overhead lines, underground transmission facilities, roads and rights of way, and miscellaneous transmission plant; load dispatching; and transmission of electricity by others in connection with existing contractual agreements.

Q. How were the figures developed for 1979, 1980, and 1981?

A. Separate estimates were prepared for each of the accounts in the transmission expense group for the years 1979, 1980, and 1981. Escalations were included for labor and non-labor expenses. Labor costs have been escalated 7% and non-labor costs have been escalated 9%.

Q. In your testimony for Chapter 8, production, you stated how the escalation factors were determined and the methodology used to determine the cost estimates for power production. Were the same factors and methods used to prepare the transmission expense estimates?

A. Yes.

Q. To develop the operation and maintenance cost estimates, I assume it was necessary to make some adjustment to the recorded years to develop a useful trend by adjusting out unusual conditions that would distort the future year

Q. cost estimates.

A. Yes, in some accounts where there were unusually high or low expenditures that would affect the recorded years usefulness for trending purposes.

Q. Was it necessary to make adjustment to the future year cost trends?

A. Yes, in four accounts only. This was necessary to provide for known significant activities for which costs would not be provided for by trending alone.

Q. What accounts did not require adjustments?

A. Account 560 - Operation supervision and engineering.
Account 562 - Operation station expenses.
Account 563 - Operation overhead line expense.
Account 564 - Operation underground line expense.
Account 568 - Maintenance supervision and engineering.
Account 569 - Maintenance of structures.

Q. Were there any Transmission accounts that were not trended?

A. Yes, one. Account 573 - Maintenance of miscellaneous transmission plant. A significant item of cost in this account is property damage. For example, in 1978, property damage comprised 90% of the total expenditures in this account. Property damage expenditures vary yearly. Trending historical property damage and escalating expenditures does not provide a realistic projection of costs. Therefore, the estimate determined by our Comptroller's Department, was used to more accurately reflect our resource requirements in the estimated years.

Q. Please identify the adjustments you did make to transmission accounts.

A. Account 561 - Operation load dispatching - 1978, $590,000 in costs associated with the Digital Dispatch Security Monitoring System (DDSMS) project were transferred to this account from a plant general work order. This cost represents indirect costs that were retained in the work order until closing. This one time cost amounted to 28% of the total costs charged to this account, and was removed from the trend period to reflect a more accurate resource requirement for estimated years.

Account 565 - Operation transmission of electricity by others. In 1978, this account included extraordinary storm damage costs for the Pacific Intertie System in the amount of $929,000. This charge was not reflective of a normal year. Therefore, $929,000 was removed from the recorded costs for 1978 to trend a more accurate future year's expense.

Account 566 - Operation miscellaneous transmission expenses. A significant item of cost in this account is Research & Development (R&D). For example in 1978, R&D comprised over 33% of the total expenditures in this account. The overall level in R&D expenditures has varied yearly, thus, R&D costs were not trended. Projections for R&D are made to the account, based on the current Corporate R&D programs. Recorded R&D expenditures were removed from the recorded years and estimated R&D expenditures were added for the years 1979 through 1981. Other costs in this account were trended.

Account 567 - Operation rents. In 1977, the Digital Dispatch Security Monitoring System (DDSMS) project was being developed, which provided greater than normal expenditures for the recorded years 1977 and 1978, amounting to $135,000 and $1,035,000 respectively. However, firm rental costs for the future years of this project are $1,044,000 per year. The DDSMS costs were removed from the trend base period 1977 and 1978, and added to the respective years 1979 through 1981. Monies in this account were not indexed to 1978 dollars, as most rental costs are contracted for firm amounts.

Account 570 - Maintenance of station equipment. In recorded years 1976 and 1977, significant expenditures were made on 500 kV transformers, 500 kV series capacitors, and 220 kV power circuit breakers. These non-routine significant expenditures resulted in greater than normal expenditures and were removed from the recorded period to reflect an accurate future year trend. A total of $750,000 was added to the future year trend for 1979 to provide for $645,000 for repairs at the Sylmar 500 kV converter station and $105,900 for 115 kV power circuit breaker repairs. The above two items are the only known significant one-time items for the future years 1979 through 1980.

Account 571 - Maintenance of overhead lines. 1978 recorded Labor was abnormally low due to 1978 being a high storm damage year. 1978 Labor was adjusted by $640,000 to normalize the effects of the 1978 storm damage and to more accurately reflect our resource requirement in the estimated years.

Account 572 - Maintenance of underground lines. In 1975, this account was credited with a $46,862 material transfer from underground maintenance to the plant transmission spare parts account. Account 572 was adjusted by adding $47,000 to the recorded amounts in 1975, to reflect the actual maintenance expense. 1974 was credited for $17,000 to remove the cost of underground material purchased in that year, which was transferred out in 1975.

Q. Mr. Knapp, as the estimates and material in Chapter 9 was based on a trending methodology, do you believe it to be correct?

A. I believe the trend estimates reflect a realistic projection of expected expenditures.

Q. Insofar as it represents opinion, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Alan J. Walker

Exhibit No. (SCE-2)______, Chapters 10 and 11

Q. Will you please state your name and address for the record?

A. My name is Alan J. Walker. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company?

A. I am Manager of Customer Service Administration in the Customer Service Department.

Q. Please refer to Exhibit No. (SCE-3)______, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Alan J. Walker", does that portion of the exhibit accurately set forth your background, training, and experience?

A. Yes, it does.

Q. Please explain the activities carried on by the Customer Service Department and your responsibility thereof.

A. The Customer Service Department is responsible for planning, construction, operation, and maintenance of the electrical distribution system; responding to and resolving customer inquiries and requests; performing meter reading, customer service, and field collection activities; and interfacing with the public, the community, and our customers.

The department is divided into five divisions, each headed by a Division Vice President or Division Manager; all reporting to the Vice President, Customer Service Department. To assist the department Vice President and these Division Vice Presidents and Division Managers, I head a staff organization responsible for developing standards and procedures in the areas of departmental budgeting and planning, administrative services, regulatory activities, customer accounting, and the development and maintenance of customer information systems. This staff is responsible also for the interrelationship with corporate staffs and Customer Service Department line organizations by providing assistance and support in implementing and administering those standards and procedures.

Q. Mr. Walker, are you testifying with respect to Chapters 10 and 11 in Exhibit No. (SCE-2)_____?

A. Yes, I am.

Q. Was the material in those chapters prepared by you or under your supervision?

A. The estimates, based on recorded expenditures in the years 1975, 1976, 1977, and 1978 were prepared under my direction. The adjustments, both to recorded expenditures and to future years 1979, 1980, and 1981 were prepared under my direction from information supplied by persons with expertise in the various associated fields.

Q. What do those chapters cover?

A. Chapter 10 covers Distribution Expenses, and Chapter 11 covers Customer Accounts Expenses.

Q. Have the costs associated with the distribution substations been included in Table 10-A?

A. Yes, they have. The costs shown in Table 10-A include distribution costs incurred by the Power Supply Department. A portion of the Power Supply Department's overhead costs is included in Accounts 580 and 590. Accounts 582 and 592 are comprised entirely of distribution substation expenses under the Power Supply Department except for a minor charge in Account 592 for Catalina operations. A portion of Power Supply Department operation and maintenance expenses is included in most of the other distribution accounts. This has been done to conform to the requirements of the Uniform System of Accounts.

Q. Have costs associated with any other departments been included in Table 10-A?

A. Yes, they have. Costs from the Right of Way and Land, Engineering and Construction, Material Services, and Comptroller's Departments are included in the distribution accounts as well as Data Processing costs in Customer Accounts Expenses, Chapter 11.

Q. Are there fluctuations in the level of distribution expense in some accounts that warrant specific comment?

A. Yes. Fluctuations normally can be expected to occur from year to year depending upon circumstances such as weather, new construction demands, major projects, etc. In the recorded costs in 1974 and 1975, there is one factor which caused considerable rearrangement of our recorded expenses.

As Mr. Hunt testified in our last general rate case Application No. 57602, (1979 test year), the Customer Service Department initiated a new function accounting system on January 1, 1975, which was designed to identify origins by establishing area of responsibility (AOR) location numbers. The combination of location number with an activity (function number) now provides us with a far better identification of expenses, as well as making it possible to identify and more properly translate functional expenses to the Federal Energy Regulatory Commission's Uniform System of Accounts. This means that some costs, formerly treated as overhead, could now be identified as direct expense, and overhead expenses formerly recorded in one of our clearing accounts were found to be more properly assigned to the other.

Because of this rearrangement of recorded expenses, it was felt that the most accurate forecasting of future expense estimates could be made using the years 1975 through 1978 as a basis, and not including the year 1974.

Q. Do you have comments concerning the fluctuations in the level of recorded distribution expense or future estimates in specific accounts?

A. Yes. As I said before, variations in the level of expense can be expected as a normal occurrence in any account due to factors such as new construction demands, weather, shifts in customer priorities, etc. However, new projects and programs, changes in emphasis on these programs, external influences, and other unusual circumstances also combine to change the level of expenditures in any particular account from year to year.

Q. Please explain the more significant of these influences, for example, Account 583 shows quite variable expenses from 1976 to 1978. How do you explain this irregular pattern?

A. Among the items included in this account, which covers overhead line expenses, the provision for uncollectible damage claims is the greatest factor contributing to these variations. In this area, 1977 and 1978 were above-average years.

Another major impact on expenses in 1977, 1978, and future years is the Distribution Circuit Management (DCM) Program. This is a conservation and load management program endorsed by the Commission and testified to in Application No. 57602, which accounts for $1.2 million in 1977 and 1978. An additional $525,000 is estimated to be spent on this program in the years 1979, 1980, and 1981.

Q. Since DCM is estimated at a lower level of expenditure in future years, why does the level of Account 583 continue into 1979 to 1981?

A. As a continuation of our conservation efforts in conjunction with the DCM Program, an additional program, Conservation Voltage Reduction (CVR), was developed and mandated by the Commission. This effort is estimated at $1.1 million total for those three years.

Q. Are the figures you have quoted, the total costs of these two programs?

A. No. An additional $1.9 million must be added to DCM and $3.1 million to the CVR Program in capital expenditures for the years 1978 through 1981 in order to view the total impact of these programs during this period. The capital expenditures under the DCM Program represent the funds necessary to maintain the existing program and to further reduce system energy losses. Under the CVR Program, each individual location will undergo a cost-to-benefit analysis prior to capital expenditure at that location.

Q. Expenses in Account 584 drop in 1978, then rise considerably in 1979. Why is this?

A. This is due mostly to the cost of patrolling and inspecting underground facilities in this account which covers underground line expenses. We experienced one of the most severe storm years in Company history during 1978. The large commitment of personnel to repairing storm damage left much less time available for the routine inspection of these facilities. Estimates for 1979 to 1981 include a resumption of normal operations in this area.

Q. If future years are estimated at "normal operations", aren't the levels estimated considerably below the average rate of escalation plus projected growth?

A. Yes. We forecast growth of underground customers at approximately 10% per year and average escalation of combined labor and other expenses at approximately 8% per year. Therefore, average escalation plus growth in the underground segment would be approximately 18% per year. However, we are estimating expenses to increase from 1979 to 1981 at an average of only 8.8% per year. Our management is fully committed to the development and implementation of productivity improvements to make this possible.

Q. Do any other accounts in Chapters 10 and 11 contain similar commitments to productivity improvement?

A. Yes. Most other accounts include some elements of productivity improvement, but this is also specifically quantified in Accounts 593, 594, 902, and 903. In each of these areas, as well as many others, steps are being taken to increase our productivity in an effort to hold down costs.

Q. Your estimates for 1979 to 1981 in Account 585 exhibit significant increases from previous levels. Why?

A. This account, which covers the operation of street light and signal systems, and primarily includes our group replacement of street light lamps on a periodic basis, now contains a major conservation program. This effort, the conversion of mercury vapor and incandescent street lights to high pressure sodium vapor lamps, a more efficient light source, is in compliance with the Commission's OII-43 which mandates this type of conversion program.

Our estimates for this portion of the program are \$1.4 million in 1979, \$3.5 million in 1980, and \$3.8 million in 1981. To this should be added the capital expenditure estimates of \$2.4 million in 1979, \$4.5 million in 1980, and \$4.9 million in 1981. Thus, the expense and capital expenditures of this conversion program, over-all for the years 1979 through 1981, comes to a total of over \$20 million and the five-year program (1979-1984) to over \$45 million.

Q. In Account 587, Customer Installation Expenses, recorded expenditures decrease from 1976 to 1978, and yet you project an increasing estimate from 1979 to 1981. What is the reason for this?

A. During the recorded years, we increased the charge for appliance repair in an effort to make this program self-supporting. This resulted in a large drop in calls for repair service, but a lesser decrease in charges received, which reduced our net deficit for the overall program. We are projecting the volume of service calls to grow slightly in future years, raising the net cost. In addition, hydraulic test activities were transferred to Account 908 in 1978, which further reduced future years' estimated expenditures to Account 587.

The cost of other activities included in this account, such as the servicing of customer installations, handling billing inquiries, and investigating customer complaints is expected to increase in future years due to customer growth and escalation. However, it should be noted that the increases average only approximately 7% per year, which is less than combined growth and escalation averages which are over 11%.

Q. Why does Account 588, Miscellaneous Distribution Expenses, show a large increase in 1978, and again in 1979, but then decrease in 1980?

A. The most significant items of expense contributing to this are the Automated Mapping Project, which was initiated in 1978, and training for the Field Accounting Program. The Automated Mapping Project was established to convert, and subsequently maintain, in excess of 70,000 facility inventory maps from paper copies to a digital computer file, through computer-aided drafting equipment. When the conversion effort is concluded in approximately 1986, the costs of maintaining and reproducing inventory maps will be considerably reduced.

The second impact is training for the Field Accounting Program, which will be discussed later. The training costs are estimated at $970,000 for 1979. In 1980, training expenses return to a lower level, causing the 1980 decrease in this account.

Q. Although the dollar amounts are not large, the percent of increase in Account 591 for 1977 is significant, but the increase in 1979 is unusually small. Why is that?

A. The years 1977 and 1978 contain greater-than-normal expenditures due to two remodeling projects in this account, which covers maintenance of structures. In 1977, this was remodeling for Load Management and the Customer Information System. The 1978 expenses include the rearrangement of facilities in the Eastern Division to accommodate Customer Telephone Representatives and relocate other departments. These expenses return to normal in 1979 and future years.

Q. Again, although the dollar totals are relatively small, the percent of increase in Account 597, Maintenance of Meters, in 1977 was approximately 34%. What caused this?

A. This was primarily due to two factors. First, the Commission requirements on time-of-use metering and load research caused significant increases in expenditures during 1977 and future years. Also, as testified in Application No. 57602, purchases of heavy duty locking meter rings were accelerated in 1976 and even more in 1977 and 1978 in an attempt to control losses due to unauthorized use and theft of energy.

Q. Account 598 shows widely varying expenditures, especially high in 1978. Why does this occur, and how are the forecasts developed?

A. Storm damage and amounts accrued for property damage self insurance of distribution plant make up almost the entire amount of Account 598. Levels of expenditures change considerably due to the severity of storms encountered. As I mentioned earlier, 1978 was a particularly harsh storm year, and expenses rose accordingly. In order to levelize these high and low years and fairly compensate for both, we based our forecast on a five-year average of actual losses from 1974 to 1978, adjusted to 1978 cost levels. Future years were then escalated appropriately for each year.

Q. Mr. Walker, let's turn to Customer Accounts Expenses, Chapter 11. In the years 1976 to 1979, the average annual increase in Account 902, Meter Reading Expenses, is approximately 11%; but future years' increases are considerably less. Why?

A. Actually, the 11% average increase per year corresponds favorably with the average escalation of 8% and customer growth rate of 3%. However, as I mentioned previously, this is one of the accounts where we have established a specific commitment to productivity improvement. Therefore, we are reducing the funds which have been requested by straightline trending by 3% in 1980 and by 5% in 1981. I think this is a concrete example of our determination to slow down the rise of costs in the future.

Q. The costs in Account 903, Customer Records and Collection Expenses, have risen more rapidly from 1976 to 1979 than they are projected to do in 1980 and 1981. Please explain.

A. Expenses associated with the development, implementation, and maintenance of the Customer Information System caused heavy increases in 1977, 1978, and 1979. Although the development of future phases of CIS will require ongoing commitment of funds, in latter 1979 and 1980, less expensive equipment and terminals are replacing the older, costlier units which will cause a significant reduction in costs for 1980 and 1981.

Offsetting much of these savings, though, are the increased costs of preparing customer bills in 1979, 1980, and 1981 due to required rate structure changes. This includes the development costs, the intricacy of the newer rate structures which require more data processing time to compute, and the new expanded bill format which takes longer to print. Also, customer growth during this period adds to the expense.

Q. Then, how do you estimate an average annual increase of only 5.9%?

A. Our stated productivity improvement goals, which cover reductions in costs from the adjusted historical trend line, are over $600,000 in

1980 and almost $1 million in 1981. This makes it possible to help reduce the rise in our cost of operation.

Q. In Account 904, Uncollectible Accounts, there is a significant increase in 1979 and future years. How are these estimates prepared?

A. A five-year average of the net writeoff as a percent of base revenue was calculated. This average writeoff percent was then applied to the estimate of base revenue, as reflected in Chapter 7, for the years 1979, 1980, and 1981.

Q. Now, Mr. Walker, Accounts 580, 590, and 901, Operation Supervision and Engineering, Maintenance Supervision and Engineering, and Supervision of Customer Accounts Expenses show a similar jump in 1979 with much lesser increases in 1980 and 1981. What is the reason for this pattern?

A. These accounts include not only the cost of supervision but also various expenses associated with department, division, and district staffs and support groups; lost time due to inclement weather; preparation and processing of work orders; and engineering and service planning. They also include the cost of certain programs and projects of general benefit to more than one expense account, or to expense as well as capital expenditures. The majority of these costs are distributed, through clearing accounts, to expense Accounts 580, 590, and 901 and work orders on the basis of direct labor charges.

The years 1977 and 1978 were lowered considerably from 1976 levels by the department staff reduction. Another influence on the less-than-normal expenditures in 1978 was the heavy storms. Since direct labor charges to storm functions and work orders were extremely high, more of the allocated costs which would have gone to Accounts 580, 590, and 901 were charged to capital expenditures and the storm damage reserve. This held down 1979 allocations to Accounts 580, 590, and 901.

Additional expenses which will tend to raise allocations to these accounts in the years 1979 through 1981 include unusually high costs of lost time due to inclement weather in 1979, the Field Accounting Program, and the new Material Management System.

The Field Accounting Program is a system to simplify, and provide direct input through local computer terminals, the information for accounting and timekeeping on construction crews. This program, after implementation, will reduce field accounting and clerical costs.

The new Material Management System, through its associated computer input terminals, provides on-line access to material information and transactions which will reduce material stockouts, enhance material forecasting, and also reduce field accounting and clerical costs.

Q. Mr. Walker, insofar as the material in Chapters 10 and 11 is of a factual nature, do you believe it to be accurate?

A. Yes, I do.

Q. Insofar as it represents opinion, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Edward A. Myers, Jr.

Exhibit No. (SCE-2)______, Chapters 12 and 13 (Part)
Exhibits Nos. (EAM-1)______ (Part), (EAM-2)______, (EAM-3)______, (EAM-4)______

Q. Please state your name and address for the record.

A. Edward A. Myers, Jr. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with Southern California Edison Company?

A. Vice President. My areas of responsibility include Conservation and Community Services, Corporate Communications, and Revenue Requirements.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Edward A. Myers, Jr.", does that portion of the exhibit accurately set forth your background, training, and experience?

A. Yes, it does.

Q. What is the purpose of your testimony?

A. My testimony presents Edison's management, staff and line commitment to conservation. As used in this testimony, the term "conservation" covers both load management, or capacity-saving activities, and conservation, or energy-saving activities. My testimony addresses the propriety of expenses for conservation activities, as contained in Chapter 12, presents an overview of conservation programs planned for the test year, and outlines impending requirements of state and/or federal regulatory bodies. My testimony also relates to those minimal nonconservation advertising and public information function expenses contained in Chapter 13, matching them to guidelines set forth by this Commission.

Q. Mr. Myers, does Edison have a conservation policy?

A. Yes.

Q. Could you please describe that policy?

A. Yes. For over ten years, our conservation activities have contributed to more efficient use of electricity.

Edison's conservation policies are reflected throughout the body of our total Application. The Company has long recognized the need to respond with vigor and imagination in an effort to moderate the current and projected demand for electricity which, even if partially stemmed, will require increasingly larger expenditures for future generation and transmission facilities.

Additionally, Edison recognizes that energy supplies are becoming increasingly more expensive and scarce. To minimize facility and fuel expenditures to the extent possible, Edison has undertaken extensive energy conservation programs designed to accomplish three basic objectives: (1) to increase the efficiency of electricity usage by all customer classes, (2) to reduce energy waste through education and example, and (3) to moderate the growth of system peak demands. In addition to these basic objectives, three other Company policies have considerable influence on our conservation program planning: (1) to meet necessary growth in an orderly and financially feasible manner, (2) to develop greater dependability and persistence of conservation achievements such as through the application of reliable point-of-use control hardware, and (3) to meet the need for increased productivity achieved when the cost effectiveness of each conservation program is optimized. Lacking a concise universally-accepted definition of cost effectiveness, Edison considers a program to be cost effective when it can be implemented for less than the cost of providing new supplies. As I testified in previous proceedings, it is also our policy to complement, to the extent possible, the programs of others without being duplicative. These conservation policies are supported by senior management s ongoing commitment to conservation as evidenced by executive and line officer involvement on various oversight committees described hereafter.

The first example is the Corporate Communications Advisory Committee which was formed in 1971 and originally chaired by Executive Vice President Howard P. Allen. Comprised of key line and staff officers, it is charged with reviewing and approving all formal internal and external corporate communications policies. This Committee approves the planning and implementation of public awareness and advertising of conservation activities and regularly monitors the results.

Second, in 1975, the Peak Demand and System Capacity Factor Management Committee was established by the Chairman of the Board and is currently chaired by Senior Vice President David J. Fogarty. It consists of all line officers with operating responsibility, as well as supporting staff officers. The Committee is charged with delineating conservation and operating policies and procedures which will reduce Edison's future construction commitments and optimize fuel inventories, while maintaining a viable financial position. In this connection, it reviews all customer load management and load limiting conservation programs as well as programs internal to the Company involving power-saving techniques. The Committee regularly monitors the results.

Third, we formed an Energy Services Committee consisting of department heads from all affected areas of Company operations to expedite the analysis and approval of alternative means of satisfying customers' needs for energy services other than electricity, which services would be provided under filed rates from the Company's electric power system. The Committee chairman is accountable to the Executive Vice President and is responsible for developing economic and engineering analyses and proposing energy services facilities, including on-site generation facilities, and either Company or customer-owned alternative energy systems, including wind and solar power. The Committee also approves parameters for negotiations with the customer for such installations.

Fourth, a Rate Committee consisting of Company line and financial officers oversees the development of conservation-related rates, including marginal cost-based rates, time-of-use rates, seasonal rates, standby rates, and other innovative rate approaches.

Edison accepts the responsibility to convince its customers that conservation is more essential today than ever before. Conservation is one effective technique to minimize the impact on customer bills of the costs of construction for generation and transmission facilities required to meet our customers' future electric requirements. Further, conservation is an effective means to minimize the purchase of costly fuel oil to operate generation facilities.

Certainly, our policy is influenced by requirements of and directives from various state and federal regulatory agencies, but it is guided primarily by existing decisions of this Commission. For example, in Decision No. 84902, this Commission indicated its intention to make "...the vigor, imagination, and effectiveness of a utility's conservation efforts a key question in future rate proceedings...". This is precisely our conservation policy: the ascertainment, stimulation, and implementation of vigorous, imaginative, and effective conservation efforts. We appreciate the valuable assistance of the Commission's conservation staff and of other interested parties in this endeavor.

We have prepared this Application proposing an increase in the over-all resource commitment to conservation programs. We seek to improve upon the historical levels of conservation achievements which were made possibic by the conservation expense allowance levels authorized in the general rate decision effective January 1979. It is anticipated that each of the proposed programs will further increase the efficiency of electricity usage, moderate system peak demands, and reduce energy waste.

The proposed programs for test year 1981 will expand successful longstanding activities, introduce new conservation concepts, and sustain a needed conservation awareness program which underlies all successful efforts to stimulate the consuming public to practice conservation. Our programs reflect a growing reliance on an educated, motivated public, encouraging the selection and installation of efficient appliances, providing for expanded energy audit interfaces for all customer classes, and voluntary acceptance of time-of-use rates and/or hardware. Further, our proposals anticipate certain impending requirements of this Commission, the California Energy Commission, and the National Energy Acts, providing for appropriate actions if, as, and when required.

Q. Please discuss each FERC account designation in Chapter 12 and the activities included in each account.

A. Chapter 12 contains conservation activities which are accounted for in FERC accounts 907, 908, 909, and 910.

Account 907 is "Supervision" under the current definition in the Uniform System of Accounts, and includes labor and expenses incurred in the management and supervision of the conservation activities carried on by the Conservation, Communications and Revenue Services Departments, plus an allocation of centralized departmental administrative support activities related to conservation activies and Customer Service overhead costs associated with our field conservation forces and their efforts in customer conservation.

Account 908 is designated "Customer assistance expenses". As defined in the Uniform System of Accounts, this account includes labor, materials used, and expenses incurred in providing instructions or assistance to customers, the object of which is to encourage safe, efficient, and economical use of the utility's service. This account contains the bulk of the expenses incurred in developing and carrying out our conservation programs. Exceptions are those advertising expenses supporting general public awareness of conservation and the advertising components of specific conservation activities which are contained in Account 909, as I will explain later.

Specifically, Account 908 includes the labor and administrative costs of staff and field personnel who plan, implement, and monitor our customer conservation programs, together with related material and program costs.

Account 909 is titled "Informational and instructional advertising expenses". Under the Uniform System of Accounts, the labor, materials used, and expenses incurred in activities which primarily convey information as to what the utility or others, such as federal and state regulatory agencies, urge or suggest customers should do to conserve electric energy or capacity are included herein. Generally, Account 909 covers conservation media advertising and other appropriate communication costs related to conservation such as allocated labor and expenses of certain Corporate Communications personnel for their relevant conservation activities; expenses for development and placement of conservation advertising for general circulation; preparation and distribution of conservation booklets, brochures, and bill stuffers; construction, installation, and maintenance of fixed and mobile conservation displays and exhibits in Edison offices and at public gathering places. This account also includes all related communications activities which serve to provide customers with continuing information, both to achieve immediate reduction in use of electricity or a shift in time of use, as well as to establish and maintain a broad public base for a better understanding of the need for personal and corporate conservation efforts.

Account 910 is "Miscellaneous customer service and information expenses". This account includes the labor, materials used, and expenses incurred in connection with customer contact and informational activities which are not includable in other customer information expense accounts. At the present time, and looking forward to test year 1981, it is not anticipated that any of our conservation expenses will be charged to this account.

Q. What level of funding for conservation was authorized in base rates by Decision No. 89711?

A. A funding level of $20 million was authorized.

Q. What level of results corresponds with this level of funding?

A. Estimated 1979 results for customer-oriented conservation activities, the first full year the funding level would be in effect, are an energy reduction of approximately 1.2 billion annualized kilowatthours and a demand reduction of approximately 201 megawatts. Recorded results for 1978, contained in Exhibit No. (EAM-4)_____ were an energy reduction of approximately 700 million annualized kilowatthours and approximately 184 megawatts of demand reduction.

In addition to these 1979 projected and 1978 recorded results which relate to Chapter 12 funding, Edison conserved 900 million kWh during 1978 and will conserve an estimated 1.5 billion kWh during 1979 and through such programs as Conservation Voltage Reduction (CVR), Distribution Circuit Load Management (DCM), and High Pressure Sodium Vapor (HPSV) Streetlight Conversion, which are not chargeable to Chapter 12.

Q. Do the expenses presented in Chapter 12 represent Edison's total conservation effort?

A. No, Chapter 12 represents only the expenses for FERC Accounts 907 through 910, consistent with the Uniform System of Accounts guidelines. These accounts represent expenditures for conservation to be achieved on the customer's side of the meter. The 1981 test-year costs associated with conservation on Edison's side of the meter for programs such as Conservation Voltage Reduction, Distribution Circuit Load Management, HPSV Streetlight Conversion, as well as Conservation Research and Development are accounted for in other chapters consistent with the Uniform System of Accounts guidelines and are addressed by other witnesses.

Q. How is the effectiveness of conservation programs measured?

A. We have utilized several methods of measurement in the past and plan to continue and improve upon these. We have been working with the staffs of the CPUC and the CEC to develop appropriate criteria and methodology to measure the effectiveness of conservation programs. To this end, we are utilizing several measurement methods including: (1) direct activity reports by our field people of actual energy-use reductions by our customers, (2) surveys, (3) installed hardware, (4) testing results and extrapolations therefrom, (5) partial "report card"-type customer billing, and (6) recorded sales results. Also, Edison has developed an econometric methodology to measure conservation. Our approach utilizes econometric techniques to isolate and identify estimated electricity savings due to conservation in the Edison service territory. The model provides for variables such as weather, income, price, etc.

Since our initial effort in this regard in January 1978, we have maintained and refined the technology involved, reflecting the advice of regulatory staffs and consulting econometricians. Details of the econometric model and other measurement techniques are shown in Exhibit No. (EAM-3)______.

Q. Mr. Myers, referring to Table 12-B, why did the average residential annual use per customer increase at a higher rate in 1978 than in other years subsequent to 1973?

A. This increased usage was caused by several interrelated factors. One important factor was a three percent increase in the number of residential customers. Many of these added customers purchased new homes located in some of the warmer areas of the Edison service territory (Riverside County, San Bernardino County, east San Gabriel Valley, etc.), thereby adding air conditioning load to the system. Other additional customers were master metered mobile home parks and apartments, previously billed on Edison's commercial General Service rates, who during 1978 were given the option and elected to be billed on the new Domestic Service Multi-Family Accommodation - Submetered Rate to take advantage of lifeline rate availability. After the rate change, these customers were counted as domestic customers, therefore, impacting the increased residential customer kWh usage. Another contributing factor was the unusual weather conditions for 1978, which were more extreme than in 1977. These conditions reflected additional heating and cooling requirements.

Q. Mr. Myers, has Edison accumulated the energy savings and the capacity reduction from its conservaton programs in the past?

A. Yes. We have measured the results from our programs since 1973. If we add up all the savings that we have reported for conservation programs on Edison's side of the meter, it totals to over 2.8 billion kWh and over 500 MW. This translates to 4.5 million barrels of oil and a plant the size of San Onofre Unit 1 in deferred capacity. However, we know that many of these results overlap, do not persist, and are not additive. As we have previously testified, the only proof of long-term conservation results are the realized departures from the original estimates of sales and capacity requirements.

Q. Has Edison measured its persistence of conservation savings?

A. Our existing measurement methods have been employed to determine the results of conservation programs implemented during a specific year. In addition, we have life-cycled results of hardware programs over the estimated life of the hardware. As stated earlier in my testimony, the only dependable results for which we could either defer building plant or reduce purchases of expensive fuel oil are those results which become permanent (for example, hardware in place). The most meaningful benefits are those resulting from our load management programs whereby Edison can depend on reductions in demand from load management hardware during times of capacity shortage. We also believe that the results of our commercial, industrial, and agriclutural audit program are reliable to the extent that more than 50% are due to hardware changes and that both the hardware and behavioral actions have been validated in the field. Additionally, recent developments in computer capacity will allow our conservation analysts to develop a data base as input for our persistence measurement plan.

Savings from behavioral actions are the most delusive of the results reported for our programs. In developing a plan to measure the persistence of behavioral actions, we welcome the advice of the Commission staff and others.

Q. Is a data base being developed for persistence and other measurement activities?

A. Yes. End-use equipment saturation, demographics, square-footage, and other data are being collected by Edison individually and in cooperation with state agencies. In 1980, we will initiate the development of a plan for data collection and analysis to determine persistence of savings. In future years, this data base will be utilized to give Edison and the Commission a better handle on other conservation measurements.

Q. Has Edison determined the over-all potential for conservation in its service territory?

A. For each conservation program in test year 1981, Edison planners have estimated the potential savings for that particular program utilizing available marketing data and unit energy savings determined by engineering calculations. However, determination of the over-all potential is a difficult, if not impossible, task.

The ultimate potential lies in the hearts and minds of each individual customer; in realizing this potential, each customer must perceive either crisis or selfish benefit.

There is great appeal, and it is relatively easy to arbitrarily assign a percentage to recorded usage, but to analyze and develop programs with real feasibility is a difficult job. To this end, we are working very hard and expanding our efforts.

We have abided with arbitrary quotas, but for many years, our concentration has been on getting customers to develop a positive attitude toward conservation and to voluntarily respond to our conservation programs. Our own goal is to maximize each individual's conservation potential wherever and whenever possible within our existing resource commitment. Toward this end, we have focused on installed hardware, an ongoing barrage of messages, and one-on-one communications.

The facts are that the Company has reduced by nearly one-half its growth projections for peak demand and kilowatthour consumption from the growth rate projected prior to the oil embargo in 1973. We recognize that this lower growth rate is a result of many factors which are difficult to isolate and even more difficult to quantify. We also recognize that the programs sponsored by regulatory agencies and others have had a positive effect on lessening our growth rate, and we appreciate this support.

Q. Please describe the specific conservation program Edison has planned for 1981.

A. For its 1981 Conservation/Load Management Program, Edison has combined successful ongoing programs and new activities to establish a base $25 million annual effort. An additional $14 million is also included for programs which, at this writing, appear to be slated as mandatory by either the California Public Utilities Commission, the California Energy Commission, and/or the National Energy Acts. In our base program, efforts will be divided between two primary market targets, residential and nonresidential, in two areas - conservation and load management. We separately address our expanding cogeneration and solar activities. It is estimated that the customer-oriented base and supplemental conservation programs, as described in this chapter, will, if successfully implemented in the 1981 test year, lower anticipated annualized kilowatthour sales by approximately 2,021,457,900 kWh and reduce system demand by 252.6 MW. The ten major categories comprising the 1981 base program are:

1. Nonresidential Conservation
2. Nonresidential Load Management
3. Cogeneration
4. Residential Conservation
5. Residential Load Management
6. Solar

7. Public Awareness
8. Advertising
9. Measurement
10. Management in Conservation and Load Management Activities

The detailed descriptions of the individual plans and programs included in the ten major activity categories are contained in Exhibit No. (EAM-1) ______ and will be described by Ms. Margo A. Wells of Edison's Conservation Division staff.

Q. Please explain the increase in base funding required for your proposed 1981 programs compared with the funding level authorized by Decision No. 89711.

A. The increase in base funding from the $20 million authorized by Decision No. 89711 to the $25 million required for our proposed 1981 programs is responsive to Ordering Paragraph 8 of Decision No. 89711. Paragraph 8 directed Edison to "...continue programs designed to produce conservation, increase efforts to developing conservation oriented rates based on marginal costs, and apply vigor and imagination to developing new, innovative, and cost-effective conservation programs". The requested base level of funding reflects the orderly growth in Edison-originated programs. Our Application also reflects an additional 14 million conservation dollars to cover the estimated cost of incremental programs mandated subsequent to Decision No. 89711 in Application No. 57602. Our total request for customer conservation is $39 million.

Q. Please identify the specific programs you consider incremental to the base funding and explain how they are "mandated".

A. Exhibit No. (EAM-1)______ contains a chart showing Edison base programs plus incremental mandated or potentially mandatable programs.

Specifically, mandated programs include the Residential Conservation Services program (RCS) mandated by NECPA; the Residential Load Management Standard mandated by the Load Management Standards adopted by the California Energy Commission; the End-Use Surveys required by Title 20 of the California Administrative Code which are utilized by the CEC in the Biennial Report/Common Forecast Cycle; maintenance of the Standard Industrial Classification (SIC) Coding for nonresidential customers; below market rate financing for insulation and solar water heating systems; expanded promotional activities for solar in both new construction and retrofit of existing dwellings; and an apartment cogeneration project. These specific programs result in costs incremental to those presented in Application No. 57602 and cannot be accommodated within the present level of base funding if we are to sustain and expand the utility-sponsored effort acknowledged in Decision No. 89711.

Q. What level of results do you estimate from these supplemental mandated programs?

A. Our estimate of the level of results associated with the supplemental mandated programs in test-year 1981 is a reduction of approximately 19,178,900 kWh on an annualized basis.

Q. What level of total results do you estimate from your proposed 1981 programs?

A. Exhibit No. (EAM-1)______ presents the estimated results of all of our proposed 1981 test-year programs which are summarized as follows:

<u>Customer Conservation</u>			
Base	2,002,279,000	Annualized kWh	252.6 MW
Supplemental	19,178,900	Annualized kWh	--
Total	2,021,457,900	Annualized kWh	252.6 MW
<u>Edison System Conservation Total</u>*	1,692,000,000	Annual/Actual kWh	--

* Includes Conservation Voltage Reduction.

Q. Is the request for 1981 conservation programs funding a request for the authorization of specific programs or a request for a level of funding?

A. The programs contained in our Application are representative of our present thinking as to an appropriate level of base conservation funding, and for the Commission's determination, an estimate of the funding impact of supplemental/mandated programs.

Edison has accepted the responsibility of evaluating conservation programs. We determine their effectiveness with help from the state and other inputs. We have been involved in conservation efforts since 1971. We believe we have the experience and qualifications to appraise each program, and we certainly have the desire to succeed in conservation. Certainly, any program which is not effective must be amended or terminated. However, if any programs are terminated or reduced, new programs must replace them in order that the approved level of expenditure be maintained.

Also, we accept our responsibility, as prudent managers, to seek out and act upon opportunities for increase productivity and are mindful that we are accountable to regulatory bodies, the public, and our stockholders. We view our base request from this perspective as authorization for a level of funding rather than a request for the authorization of specific programs.

Insofar as mandated programs covered by our supplemental request, authorization of specific programs would be desirable in all cases and even necessary in some cases.

Q. Does this complete your testimony on Chapter 12?

A. Yes, it does.

Q. Please discuss the Advertising and Public Relations Expense contained in Chapter 13 and explain why this testimony appears in this position in the case.

A. In Decision No. 86794 in Application No. 54946, the Commission set forth guidelines regarding our advertising and public information expenditures. Guided by this decision, we reviewed all of our advertising and public relations activities, allocating conservation activities to Accounts 907, 908, and 909 in Chapter 12 and allocating approved types of nonconservation activities in Chapter 13 to Accounts 920, 921, 923, 926.1, 930.1, and 930.2. This testimony and accompanying Exhibit No. (EAM-2)______ describe the conservation-related and nonconservation-related advertising and public information pursuant to CPUC guidelines.

Q. What did Decision No. 86794 offer as guidelines for information advertising?

A. Decision No. 86794 stated:

"All institutional advertising shall be disallowed for ratemaking purposes. Furthermore, all other advertising, except that which is listed below, shall also be disallowed for ratemaking purposes.

"a. Financial advertising.

"b. Safety messages.

"c. Essential customer services information such as changes in location of offices, telephone numbers, payment agencies, and announcements of regulatory proceedings before this Commission or other regulatory agencies.

"d. Results-oriented, specific conservation advertising; this must, however, be accounted for separately as a conservation expense."

To help clarify this allocation, Exhibit No. (EAM-2)______, Table 1, has been prepared with the cost breakdown and samples of our advertising activities, both conservation and nonconservation. The conservation advertising activities as specified in item d are covered in Chapter 12. Expenses for nonconservation activities, as stated in Items a, b, and c, are covered in Chapter 13.

Q. What about public relations?

A. At Edison we have no Public Relations department, per se. The advertising activities approved by Decision No. 86794 are accomplished within the Corporate Communications Department and the Conservation and Community Services Department.

Q. What other guidelines have been provided by the Commission?

A. With respect to public relations, the Commission provided the following policy clarifications in Decision No. 86794:

"...it shall be the policy of this Commission henceforth to exclude from operating expenses for rate fixing purposes all amounts claimed for public relations expense for which it cannot be shown:

"a. Provides normal liaison with, and channels of communication for, representatives of the press, radio, television, and other media.

"b. Results in reduction of operating costs and more efficient service to the ratepayers.

> "c. Encourages the more efficient operation of the utility's plant, the more efficient use of the utility's services, or the conservation of energy or natural resources, or presents accurate information on the economical purchase, maintenance, or effective use of electrical or gas appliances or divices.
>
> "d. Presents factual discussion of specific topics dealing with plant siting, safety, and environmental impact.
>
> "In future proceedings involving this and other utilities, we shall expect the utility to justify, and our staff to verify, public relations costs in detail and to supply, for the record, information on each aspect of the utility's public relations program so that we may make judgments regarding the reasonableness of each activity and of appropriate reasonable allowances."

Exhibit No. (EAM-2)______, Table 2, shows examples of our "public relations" activities and the allocation of costs associated with those activities.

We consider these nonconservation public relations activities essential to public understanding and support of Edison's efforts to provide adequate electric service to its customers. Our philosophy for both conservation and nonconservation communications programs has been a one-on-one approach. Toward this end, we have substituted large group/lecture-series for workshop-type meetings and have developed oral, visual, and written communications to specific segments of the public in and around our service territory. Incorporated are factual discussions of Company concerns relating to siting, alternate energy sources, and environmental impact, each of which meets the Commission guidelines.

Provision is also made for personnel to respond to inquiries by TV, radio, and press on all newsworthy activities in our 14-county, 50,000 square-mile territory.

We think the programs we have allocated to nonconservation communications activities accounted for in Accounts 920, 921, 926.1, 930.1, and 930.2 represent minimum staff for these critical times when public understanding is so vital to both the utility and regulator.

Q. How do you measure the effectiveness of your advertising/public relations activities, both conservation and nonconservation?

A. There appears to be no direct method of measurement for energy reductions or other public response attributable to advertising or other public relations activities. As an alternative, Edison took a benchmark survey in 1976 of a statistical sample of all customers to determine awareness and attitude about such topics as the energy issue, conservation, research and development, utility rates, and Edison as a company. This survey established a means by which, through tracking surveys, a gauge of public awareness of the conservation ethic as well as the need for and effectiveness of any specific advertising or publicity could be determined. Exhibit No. (EAM-3)_____ contains a summary of our most recent results. The results of this and other surveys, as well as reports from field customer contact personnel, will help us to be more responsive to consumer shifts in attitude and priorities. Further, it is utilized to help tailor our communications efforts to our customers' needs.

Q. Does Edison utilize copy testing?

A. Benefiting from suggestions provided by intervenors in earlier proceedings to assure that advertisements communicate the intended messages in a clear and understandable manner, pretests are conducted by our advertising agency. The results of these pretests have been most encouraging. As an example, the pretest of our augmented summer capacity crisis campaign revealed that 92% of the target audience said that after seeing the advertisement, they would try to follow the suggestion to "Give their Appliances the Afternoon Off".

Q. To the extent the material in Chapter 12 and advertising and public awareness components of Chapter 13 of Exhibit No. (SCE-2)______ as well as supplemental Exhibits Nos. (EAM-1)______, (EAM-2)______, (EAM-3)______, and (EAM-4)______ is of a factual nature, do you believe it to be accurate?

A. Yes, I do.

Q. To the extent that the material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Margo A. Wells

Exhibit No. (SCE-2)______, Chapter 12 (Part)
Exhibit No. (EAM-1)______, (Part)

Q. Please state your name and address for the record.

A. Margo A. Wells. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with Southern California Edison Company?

A. Supervisor of Conservation Staff Services. My area of responsibility includes the monitoring, evaluation, and reporting of the effectiveness of the Company's conservation and load management programs.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Margo A. Wells", does that portion accurately set forth your background, training, and experience?

A. Yes, it does.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present detail on Edison's proposed 1981 base conservation plans and programs within the ten major activity categories presented in the testimony of E. A. Myers, Jr., which are properly charged to Chapter 12 and contained in Exhibit No. (EAM-1)______.

Q. What is included in the Nonresidential Conservation activity category?

A. In the Nonresidential Conservation Activity category, Edison will continue its very successful commercial, industrial, agricultural, and public authority energy audit program which was initiated in 1973.

The audit effort will be augmented by: mailing a New Customer Conservation Booklet containing self-help audit information to new commercial/industrial customers shortly after service is requested; recognizing and presenting Energy Management Awards to businesses and industries who have made outstanding conservation efforts; utilizing a mobile display that showcases conservation hardware applications for customer inspection; offering an electric water heater thermostat turn-down service; initiating a series of campaigns designed to encourage electrical contractors, refrigeration mechanics and technicians, wholesale suppliers, and HVAC contractors to promote conservation hardware with Edison customers at the time of equipment servicing; and promoting conservation hardware through a coupon-incentive campaign.

Edison will lend impetus to its Agricultural and Water Pumping Test program by offering a Pump Test and Adjustment program which requires deep well turbine pump customers to have a contractor at the pump site to make the appropriate adjustments at the time of the Edison pump test. Edison will also offer a free feasibility study for utilizing heat recovery equipment in milking parlors with electric water heaters.

Q. What is included in the Nonresidential Load Management category?

A. In the Nonresidential Load Management category, directed at its commercial, industrial, agricultural, and public authority customers, Edison will continue its evaluation of off-peak systems and utility-activated load cycling systems for contribution to peak demand reductions. The submetering and analysis of nonexperimental and experimental time-of-use rate designs will also be continued.

Q. What is included in the Cogeneration category?

A. In the Cogeneration category, Edison will continue to encourage the installation of cost-effective on-site generation by commercial and industrial customers, which can be operated in parallel with the Edison system for the benefit of all ratepayers.

The potential for residential cogeneration and customer-owned auxiliary generation is also being investigated. Edison has begun to assess the market potential in this area and to further define the potential for peak shaving by customers.

In addition, Edison is also working with several customers who are planning to develop cogeneration projects using biomass, landfill methane recovery, or solid waste conversion.

Q. What is included in the Residential Conservation category?

A. In the Residential Conservation category, to reach the more than 2.7 million residential customers, Edison utilizes programs keyed to the concerns of individual households to disseminate appropriate conservation suggestions and information relevant to hardware applications.

Such efforts will include a revised new customer booklet containing self-help audit information; a computer audit activity (SAVES); an in-home audit activity (Sherlock) supported by small group meetings (Conservation Workshops) where the "how-tos" of conservation will be demonstrated and discussed; a master meter apartment/mobile home park activity to stimulate cooperative owner/tenant conservation efforts; a toll-free Conservation Information Line that provides nonEnglish-speaking customers an opportunity to communicate with a talking computer that can respond to conservation/load management questions in any programmable foreign language; an evaluation of the cost/benefit of expanding communication efforts with Spanish-speaking customers; participation in the National Energy Watch program aimed at encouraging the installation of conservation features in both the new and retrofit housing markets; an animated mobile van show designed to be shown at shopping malls, fairs, and shows to attract and entertain audiences while conveying conservation/load management information; a series of public service television programs, related to conserving energy in the home, to be produced and made available to cable, community, and network television stations; and Conservation Corner, a hardware/device showroom.

Ongoing conservation hardware-oriented activities will include Home Insulation, an activity to encourage home and apartment owners to upgrade attic insulation; and Wrap Up II, which will continue to offer electric water heater customers free water heater insulation blankets and low-flow shower heads. New programs feature De-Light, a program whereby Edison will work with youth organizations to promote the use of low wattage light bulbs; Secondary Refrigerator Reduction, a program designed to remove inefficient refrigerator/freezer equipment from the marketplace; Energy Efficient Appliance program, a number of activities designed to expand public awareness on the availability of energy efficient appliances including refrigerators, freezers, and air conditioners that exceed state appliance efficiency standards; and Off-Peak Refrigerator Development, which will involve the production and merchandising of a new energy efficient refrigerator.

The Residential Activity for 1981 will also include a number of technical support and energy-use research activities such as Appliance Retrofit Research, Efficient Appliance Use Testing, Research on Consumer Energy Use Patterns, and a Heat Pump Water Heater Test.

Q. What is included in the Residential Load Management category?

A. In the Residential Load Management category, Edison will emphasize utility-activated load cycling experiments, time-of-use rate experiments, new meter developments, a swimming pool pump deferral effort, several off-peak cooling tests, and a consumer education load-shifting campaign utilizing the theme "Give Your Appliances the Afternoon Off."

Q. What is included in the Solar category?

A. In the Solar category, Edison's objective is to (1) encourage builders of new housing developments who have elected to install electric water heaters to also install solar water heating systems, and (2) to make solar end-use device information available to existing homeowners with electric water heaters to encourage retrofit solar applications. Further expansion of this activity is pending a decision in OII No. 13, as well as OII No. 42.

Edison is also investigating rate designs to enhance customer solar and wind generation project acceptance.

Q. What is included in the Public Awareness category?

A. In the Public Awareness category, Edison's efforts encompass eight major components directed at reinforcing consumer awareness of the vital need for conservation and load management. The components of this activity include such important functions as maintaining timeliness of conservation/load management communications materials (slides, brochures, bill inserts, movies, exhibits, displays, speeches, etc.) which are used with educators; students; professional organizations; federal, state, and local governmental agencies, leaders, and officials; resale customers; and the general public at large. An activity of equal importance is Edison's maintenance of media contacts in order to respond to conservation/load management inquiries and to place timely articles and news releases containing conservation/load management suggestions for our customers.

Q. What is included in the Advertising category?

A. In the Advertising category, Edison's activities include (a) the development of thematic general public awareness conservation advertising for placement in newspaper, television, and radio media to reinforce the conservation ethic and provide specific conservation suggestions for saving electric energy, and (b) advertising directed toward support of and consumer acceptance of specific conservation/load management programs.

Q. What is included in the Measurement category?

A. In the Measurement category, Edison's activities include reports, special studies, research, and personnel necessary to quantify results from specific conservation/load management programs. It also includes econometric measurement which employs multiple regression analysis to isolate the impacts of major economic variables on the consumption of electricity.

Q. What is included in the Management of Conservation/Load Management Activities category?

A. The Management of Conservation/Load Management Activities category includes the expenses and associated costs incurred by management and administrative personnel who are responsible for evaluating the over-all cost-effectiveness of the Conservation/Load Management Program and making recommendations for modification or termination of program components found to be noneffective. Also included with this activity is the training of Edison employees to further advance their skills in implementing conservation/load management activities.

Q. To the extent that the material you sponsor in Chapter 12 of Exhibit No. (SCE-2)______ and (EAM-1)______ is of a factual nature, do you believe it to be accurate?

A. Yes, I do.

Q. To the extent that the material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Ray W. Scofield

Exhibit No. (SCE-2)______, Chapter 13 (Part)

Q. Please state your full name and address for the record.

A. My name is Ray W. Scofield. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company, Mr. Scofield?

A. I am an Assistant Comptroller.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Ray W. Scofield", does that portion of the exhibit accurately set forth your background, training, and experience?

A. It does.

Q. Are you testifying with respect to Chapter 13 of Exhibit No. (SCE-2)______ for identification in this proceeding?

A. Yes, except for nonconservation advertising and public information expense, which is covered by Mr. Myers; abandonment costs associated with cancellation of planned major projects, which is covered by Mr. Whyte; and research and development expenditures, which is covered by Mr. McCrackin.

Q. Was Chapter 13 prepared by you or under your supervision except for those portions covered by Messrs. McCrackin, Myers, and Whyte?

A. Yes, it was.

Q. What subject is covered in Chapter 13?

A. Administrative and general expense.

Q. What types of expenses are charged to administrative and general expenses?

A. Charges to this classification include salaries, wages, supplies, and expenses of officers and general office employees of the Company properly chargeable to operations but not chargeable to a particular operating function; the fees and expenses of consultants and others for general services; the cost of insurance or reserve provisions to protect the Company against losses of property and against injuries and damage claims; employee pensions and benefits; franchise requirements; certain research and development work; trustee registrar, and transfer agent fees and expenses; general advertising; rents for property of others; and expenses incurred in the operating and maintaining of general plant, such as the general office building and telecommunication equipment.

Also included are credits for the amounts of administrative and general expense capitalized in Account 922 and employee benefits expense capitalized in Account 926.

Q. Referring to Tables 13-A and 13-B, Exhibit No. (SCE-2)_______, will you describe their contents?

A. Table 13-A shows administrative and general expenses, by accounts, for the years 1976 through 1981. The first three years are recorded data, while the latter three years are estimated. The two columns to the far right reflect the elimination of A & G expense relating to SONGS 2 in 1981. Table 13-B shows the estimated years with Account 927, Franchise Requirements, revised to eliminate the effect of any ECAC revenue.

Q. What is the total estimated administrative and general expense for each of the years 1979 through 1981?

A. The estimates are $149.9 million for 1979, $170.2 million for 1980, and $187.5 million for 1981.

Q. Please describe how you went about developing the estimates for 1979 through 1981.

A. First, let me point out that the administrative and general expense group of accounts is nonhomogeneous in nature and, further, in several of the accounts, many of the elements of expense bear no relationship to each other. In my opinion, this makes over-all trending impractical, but it was possible to develop certain basic trends within accounts. My basic methodology is described in the text accompanying Table 13-A. I believe the record would be easier to follow if I discuss the significant exceptions on an account-by-account basis.

Q. All right; what was the approach used for Account 920, Administrative and general salaries?

A. First, it is essential to recognize that the number of regular employees in the Company decreased by over one thousand between 1973 and 1975. As nearly 87% of all A & G labor is recorded in this account, the use of a 1974-1978 trend abnormally depressed the base trend, while, conversely, a 1976-1978 base trend developed estimates which appeared unrealistically high. I decided, therefore, to use 1975-1978 for my basic trend.

Second, I noted that in the areas of Data Processing, Law, Material Services, and Revenue Requirements, the growth trends have and are expected to increase at faster trend rates than other areas of expense in this account. Conversely, officers' salaries are projected at a lower trend rate than the base trend. Separate trends were developed for each of the areas mentioned, all on the basis of 1974-1978 recorded data.

Other exceptions in this account include Corporate Communications labor to be covered by Mr. Myers, the inclusion of Edison labor relating to anti-trust cases, and the labor required to operate a new office building to house our engineering personnel following its completion in 1980. The latter expense will be more than offset by lower rentals estimated in Account 931.

Q. Did you prepare the estimates for Account 921, Office supplies and expenses, in a similar manner?

A. Yes, although the areas of exception are not completely identical. The only significant differences, however, include a downward adjustment of the 1978 recorded amount for Office Services, as their non-labor expenses were abnormally high due to the prolonged strike in the paper industry. It should also be noted that the growth in Data Processing labor reflected in Account 920 is partially offset by an expected lower level of non-labor expenses in this account.

Q. Mr. Scofield, would you please explain the nature of Account 922, Administrative expenses transferred - Credit?

A. Yes. First, the amount of administrative expenses capitalized is based on an established percent of the charges to Accounts 920 and 921 which reflects the portion of administrative expenses associated with construction.

The percentage to be capitalized is reviewed periodically in accordance with Electric Plant Instruction 4-B in the Uniform System of Accounts. As the result of such studies, the percentages have been 32.32% for 1976, 33.82% for 1977, 32.28% for 1978, and 29.7% for the expected years 1979 through 1981.

Q. Mr. Scofield, looking at Account 923, Outside services employed, to what do you attribute the decline in 1978 and 1979 followed by an upswing in 1980 and 1981?

A. Let me comment first that the basic trend has been virtually level during the recorded period and is so projected for the estimated years. The downturn in 1978 and 1979 was caused first by the transfer of pension management fees from the account to Account 926 beginning in 1978. For 1979, legal expenses relating to employee relations were projected at the lower 1976-1977 level, as 1978 expenditures were abnormally high due to the strike by U.W.U.A. employees.

The increases for 1980-1981 are primarily due to the estimated costs of $977,000 for a third-party management audit, spread 25% in 1980 and 75% in 1981. Such an audit was ordered in Decision No. 89711. Further, the San Diego Gas and Electric Company Decision No. 90405 states "We also agree that reasonable costs for conducting a management audit are recoverable in rates as we believe such audit will be beneficial to the ratepayers."

Q. Would you explain the nature of the expenses included in Account 924, Property insurance?

A. This account contains the anticipated insurance premiums to protect the Company against losses and damages to property used in its utility operations. Additionally, it includes the amounts reserved by the Company against certain losses not covered by specific insurance policies. The estimate for the latter has been based on the five-year average (1974-1978) of recorded losses adjusted to more current price levels.

The larger than usual increase in 1981 includes $855,000 for San Onofre Unit 2 on the assumption it will become operative as of July 1, 1981.

There were no other basic trends used in this account as each of the numerous individual policies were evaluated and estimated by the Company's Insurance Division.

Q. Is Account 925, Injuries and damages, somewhat similar in nature to Account 924?

A. Yes, Account 925 includes the anticipated cost of insurance premiums to protect the Company against injuries and damage claims of others. It also contains the amounts reserved for the losses incurred through claims and suits for injuries and damages not covered by insurance. The latter was estimated on the basis of a least squares trend of recorded losses for the past five years (1974-1978).

The substantial increase estimated for 1980 relates to an anti-trust suit in a District Court for which substantial costs are being incurred in 1979, are expected to peak in 1980, and to begin to decline in 1981.

The only items subject to trending in this account were the labor and other expenses for the operation of the Company's Safety Division.

Q. Why does Edison believe it would be reasonable to pass those anti-trust litigation costs through to its customers in its rates and charges for service?

A. This litigation involves a number of contentions by certain resale customers which essentially boil down to claims of anticompetitive conduct by Edison to the detriment of such resale customers. Specifically, those customers are using this litigation as part of their effort to obtain advantageous sources of power directly from sources that are now, or otherwise might likely be, available to Edison to serve all of its customers. They are also seeking in this, and in related litigation before regulatory bodies, to obtain more favorable rate treatment which, among other things, would include the reallocation of costs as between the two regulatory jurisdictions, namely, retail and resale.

If such resale customers were to be successful in such litigation, it is likely that lower cost sources of bulk power would be made available directly to such resale customers, rather than through Edison's operations, meaning that Edison's retail customers could be significantly prejudiced in terms of the rates they pay for service. Similarly, if different methods of cost allocation between jurisdictions were adopted, as a result of such litigation, methods more favorable to resale customers, this too would result in detriment to retail customers in the form of higher rates and charges for retail service.

Since such litigation is heavily involved with these issues, it seems only fair that customers standing to benefit from these litigation efforts and expenses of the Company should share in those costs.

Q. Mr. Scofield, are there other considerations on this matter that should be made?

A. Yes, in my judgment. Recent trends of the law have made public utilities, particularly electric public utilities, far more exposed to this kind of litigation and expense than in the past. It has become, as a practical matter, part of the cost of doing business for a large electric utility, particularly one with both retail and resale operations. Many of the contentions that have to be dealt with in such litigation are the direct result of regulatory action by one or the other or both of the regulatory bodies regulating the utility's rates and other operations.

If this Commission determines to adopt a particular rate policy vis-a-vis one or more retail customer groups, that determination very possibly can become involved in such litigation. "Price squeeze" allegations are perhaps a prime example. If one regulatory commission had jurisdiction over both retail and resale rates, there might, and probably would, be no "price squeeze" problem at all. However, with dual jurisdiction, given the recent developments of the law in this area, "price squeeze" allegations and anti-trust litigation become almost inevitable. Therefore, it seems entirely appropriate that the expenses of such litigation, particularly where dual regulatory jurisdiction exists, should be looked upon as part of the ongoing cost of doing business, where such litigation cannot be reasonably avoided without the potential of disadvantaging ratepayers either in the utility's cost of bulk power supply or in terms of the utility's ability to achieve reasonable earnings results, the failure of which would inevitably prejudice the utility's ability to continue to raise the huge amounts of new capital needed to finance plant construction required to meet increased ratepayer demands for service, with the ultimate result of deterioration in such service.

Q. Referring now to Account 926, Employee pensions and benefits, to what do you attribute the substantial increase in 1979, which appears to carry forward to a lesser degree in 1980?

A. As background, the major employee benefits are basically related to one or more of the following factors: numbers of employees, wage and salary levels, and years of service. The continuing increases of all of these factors result in rising employee pension and benefit expense. The substantial increase in 1979, however, was related to the Company's negotiations with the labor unions and the resulting change in several of the benefits. The over-all benefit package is opened for renogotiation every five years. In Decision No. 89711, the Commission effectively allowed approximately $7 million in test year 1979 for this purpose.

The major benefits include Pensions, Group Life Insurance, the Employee Stock Purchase Plan, the Family Dental Plan, and Long Term Disability. These benefits were estimated by our Employee Benefits personnel on the basis of recorded trends adjusted for 1978 changes, estimated salary increases, and estimated changes in number of participants.

Labor and other expenses in this account were trended on the basis of the recorded years on either 1974-1978 or 1975-1978 bases and consist primarily of the Medical Department, the Employee Benefits Division of the Employee Relations Department, Personnel and Employee Development, and Employee Communications. Non-labor expenses used in the trend are approximately 80% medical, and the use of 1975-1978 resulted in a lower estimate for the future years.

One item of expense was added to this account in 1978, pension management fees, which was formerly included in Account 923.

This account also includes the credit for Employee Pensions and Benefits capitalized. The rate of such capitalization is determined annually on the basis of the ratio of total wages and salaries and wages and salaries charged to construction. The recorded ratio for 1978 was 29.7%, and this rate was used for the estimated years.

Q. Please explain the nature of the increases in Account 927, Franchise Requirements.

A. This account includes the amounts accrued for the payments to municipal and other governmental authorities in compliance with franchise, ordinance, or similar requirements. For estimating purposes, it is purely a function of revenue and will rise accordingly, whether such revenue is derived from base rates or from energy cost adjustment clause factors. Table 13-A1 shows this account excluding the effect of any ECAC revenues.

Q. What was the basis for the substantial increase in Account 928, Regulatory Commission expense, beginning in 1978?

A. The substantial increase beginning in 1978, which peaks in 1979, and declines somewhat in 1980 and 1981, primarily results from the costly "discovery" process relating to anti-trust type litigation involving the Company before the Federal Energy Regulatory Commission. None of these expenditures was anticipated in our prior general rate case and, therefore, none of the 1978 recorded nor the 1979-1980 anticipated expenditures is included in our present rate structure.

Non-labor expenses, excluding the anti-trust case, are based on a simple average of the past two years, 1977-1978, as any trending method produced an estimate which appeared unreasonably high.

Q. What is included in Account 929, Duplicate charges - Credit, and why is the figure not a negative amount in 1978?

A. The Company uses this account to record the value assigned to the kilowatthours used during the construction of a new generating unit. However, in June 1978, the value of the kilowatthours generated at the Cool Water Generating Station was charged to this account, resulting in a net debit to the account for the month and for the year. Excluding this, the account would have shown a negative $32,000 for the year.

Q. Are you responsible for the estimates shown for Account 930.1, General advertising expenses?

A. No. Although the grouping in the Uniform System of Accounts requires this account to be included in Administrative and General Expenses, the estimates have been provided by witness E. A. Myers, Jr., and has been covered by him in his testimony.

Q. Turning to Account 930.2, Miscellaneous general expenses, to what do you attribute the rather substantial fluctuations, both up and down, during the recorded and estimated years?

A. First let me comment that, by definition, this account was established by the regulatory authorities to accumulate those costs "not provided for elsewhere" in the Uniform System of Accounts. By its very nature, it is possibly the least likely candidate for trending.

With regard to the specific question, the write-off of major abandoned projects, historically over a five-year amortization period, has resulted in most of the fluctuations to which you referred. Other than the Kaiparowits project, the write-off for which will be completed in 1980, we are proposing a different approach for estimating costs associated with the cancellation of generating projects which are in the planning stages. Witness M. D. Whyte discusses this approach in his prepared testimony.

Additionally, the years 1976 and beyond reflect the continued emphasis on research and development, although it needs to be recognized that this account reflects only those research and development expenditures of a general nature which are not identifiable with other specific operating accounts. Witness F. A. McCrackin provides the estimates and covers them in his testimony and exhibit.

The two areas of expense I have just mentioned constitute between 70% and 80% of the dollar amounts included in the recorded and estimated years.

The estimates relating to Corporate Communications have been provided by witness E. A. Myers, Jr., and are covered by him.

One other area of expense, the net amount of A & G expense paid to or received from others, involved two variations from the basic trend procedure. First, beginning in 1978, we have been required to separate out the employee benefits segment of such expenses and record them in Account 926. Second, because detailed 1974 information was not readily available for trending purposes, I used 1975-1978 as my historical base.

The balance of the other miscellaneous general expenses in this account was projected to increase an average of less than 5.4% annually between 1978 and 1981.

Q. What types of rents are included in Account 931?

A. Generally speaking, there are two types of rents included in this account. One is additional office space. A large number of our engineering personnel have occupied rented space in an office building near the General Office since 1973. Second is the rental of telephone cables and radio and microwave systems.

The decrease in this account beginning in 1980, is due to scheduled completion of a new office building to house the engineering personnel mentioned above.

Q. What is included in Account 932, Maintenance of general plant?

A. This account includes both the maintenance of general office buildings and the maintenance and repair of telecommunication equipment, including cables, microwave, and telephone and power lines.

Two new items of expense have been added to this account. One is the maintenance of the new office building for engineering personnel I previously mentioned and the other is maintenance at our general store in Alhambra, which previously had been recorded in a clearing account.

Q. Does that conclude your explanation of the amounts shown on Tables 13-A and 13-B?

A. Yes, it does.

Q. Mr. Scofield, to the extent the material in Chapter 13 is of a factual nature, do you believe it to be accurate?

A. Yes, I do.

Q. Insofar as it is in the nature of opinion or judgement, does it represent your best judgement?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of M. D. Whyte

Exhibit No. (SCE-2)_____, Chapter 13 (Part)

Q. Please state your full name for the record.

A. My name is M. D. Whyte.

Q. Mr. Whyte, have you previously testified in this proceeding?

A. Yes, I have.

Q. Mr. Whyte, are you also testifying with respect to Chapter 13 of Exhibit No. (SCE-2)_____?

A. Yes, I am testifying on that portion of Chapter 13, Table 13-A, line 13 which refers to the abandonment costs associated with cancellation of planned major projects.

Q. Please describe that portion of Table 13-A, line 13, in Chapter 13, dealing with the abandonment costs associated with cancellation of planned major projects.

A. Edison pursues several projects to meet the anticipated increase in customer demands. Some of these projects are cancelled in the planning and licensing stages due to reasons which are not within Edison's control. The expected losses due to such cancellations are $5.68 million in 1979, $6.897 million in 1980, and $6.955 million in 1981 and are included in Table 13-A, line 13, in Chapter 13.

Q. Please list the projects included in estimating cancellation losses.

A. Future projects in the planning stages and included in the resource plan are identified in Chart 3-B, Chapter 3. As of August 1979, Edison has committed funds to pursue the following projects included in the resource plan, which can be or have been cancelled: Balsam Meadows Hydro, California

Coal, Palo Verde Units 4 and 5 (cancelled on July 16, 1979), and Thermal De NOx (AQMD Rule 475.1). In addition, Edison is pursuing the Harry Allen/Warner Valley coal projects and the Cool Water Coal Gasification Project.

Q. Mr. Whyte, insofar as the material presented with respect to the abandonment costs associated with cancellation of planned major projects, as presented in Table 13-A, line 13, in Chapter 13 of Exhibit No. (SCE-2)______, is of a factual nature, do you believe it to be correct?

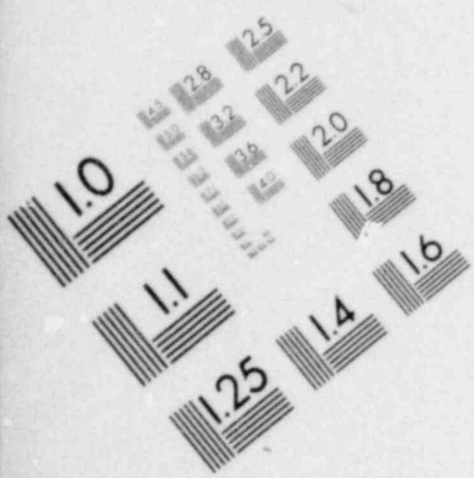
A. Yes, I do.

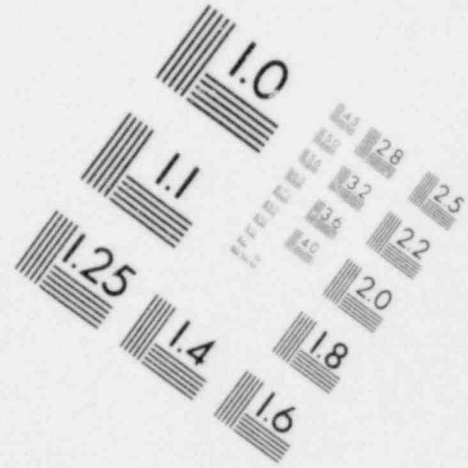
Q. Insofar as it represents opinion, does it reflect your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.





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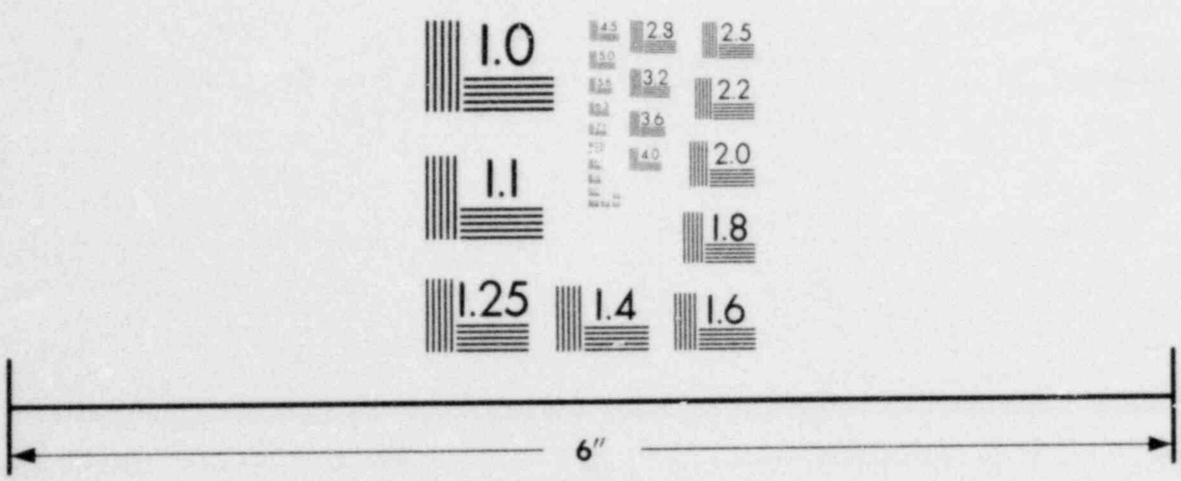

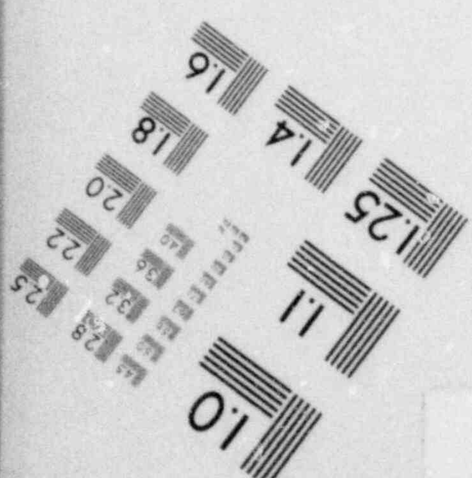

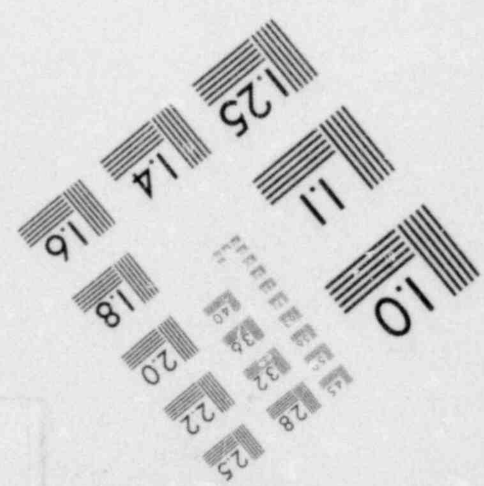

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of James S. Pignatelli

Exhibit No. (SCE-2)_____, Chapter 14

Q. Will you please state your name and address for the record?

A. James S. Pignatelli. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Company?

A. I am Manager of Taxes.

Q. Please refer to Exhibit No. (SCE-3)_____ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of James S. Pignatelli", does that portion of the exhibit accurately set forth your background, training, and experience?

A. It does.

Q. Are you testifying with respect to Chapter 14 of Exhibit No. (SCE-2)_____ for identification?

A. Yes, I am.

Q. Was the material in Chapter 14 prepared by you or under your supervision?

A. It was.

Q. Will you indicate briefly the contents of Part I of Chapter 14 relating to ad valorem taxes, as shown in Tables 14-B, 14-C, 14-D, and 14-E?

A. These tables contain recorded and estimated data for ad valorem taxes chargeable to California electric operations resulting from the taxation of Company properties located in the states of California, Arizona, New Mexico, and Nevada.

Q. Will you please explain the estimated ad valorem taxes charged to California electric operations for California properties, as shown in

Table 14-B?

A. Ad valorem taxes for 1979, 1980, and 1981, on properties located in California, are based upon the best information available regarding the measure of fair market value and other factors used by the California State Board of Equalization in determining taxable assessed values. In determining estimated ad valorem taxes, system average tax rates were estimated. For this purpose, the system average tax rates for fiscal tax years 1979-80, 1980-81, and 1981-82 were assumed to remain at the same level as the system average tax rate for fiscal tax year 1978-79.

California ad valorem taxes are based on a July 1 through June 30 fiscal year and are charged to expense in a calendar year on the basis of 50% of the lien date tax of one year and 50% of the lien date tax of the prior year. The assessment ratio for California property is 25% of market value, as provided by law.

Q. Will you please explain Column 13, "Miscellaneous Adjustments", shown in Table 14-B?

A. This column eliminates taxes which are not chargeable to electric operations. Included are capitalized taxes, gas and water utility taxes, nonutility taxes, taxes applicable to certain fuel oil handling facilities, and miscellaneous items. The taxes applicable to the fuel oil handling facilities are included in the fuel expenses covered in Chapter 8.

Q. Will you please explain the estimated ad valorem taxes charged to California electric operations for Arizona properties, as shown in Table 14-C?

A. The Arizona Department of Revenue is responsible for determining the assessed value of utility properties located in Arizona. The assessment ratio is 50% applied to the "full cash value" determined by the Arizona Department of Revenue. As in the case of California, estimates are made based upon the best information available regarding factors used in determining full cash value and regarding tax rates. For purposes of these estimates, tax rates applicable in the various taxing jurisdictions where the Company's properties are located, or to be located, are assumed to remain at the same level as they are for the latest tax year for which information is available; namely, 1978. As shown in Column 7 of Table 14-C, the "Average Tax Rate Per $100 of Assessed Value" shows a decline during the period covered in this table. This is because: although we have assumed the individual tax rates applicable to where property is located remain unchanged from 1978, the additions of new taxable value are occurring in areas where the tax rate is lower than the average.

Q. Will you please explain Column 9, "Capitalized Taxes", as shown in Table 14-C?

A. This column summarizes taxes applicable to the Company's share of Palo Verde Nuclear Generating Station Units 1, 2, & 3, which remain under construction through the years covered in this table.

Q. Mr. Pignatelli, will you please explain the estimated ad valorem taxes charged to California electric operations for New Mexico properties, as shown in Table 14-D?

A. The New Mexico Property Appraisal Department establishes the assessed value of the Company's properties located in New Mexico. Assessed value of operating properties is equal to 33-1/3% of taxable historical cost less depreciation. Taxable assessed value of property being constructed equals 16-2/3% of its recorded cost at the time of assessment. The average tax rate applied to assessed value for the estimated periods included in Table 14-D is assumed to remain at the 1978 level.

Q. Will you please explain Column 7, "Capitalized Taxes" as shown in Table 14-D?

A. This column summarizes ad valorem taxes applicable to construction of pollution control devices at the Four Corners Generating Station in New Mexico.

Q. Will you please explain the estimated ad valorem taxes charged to California electric operations for Nevada properties, as shown in Table 14-E?

A. Assessments are made in Nevada in much the same manner as in California, however, using a 35% assessment ratio applied to market value. Taxes charged to expense are based on 50% of one year's lien date taxes and 50% of the prior year's lien date taxes, as in California.

Q. Mr. Pignatelli, in line 4, "Average Tax Rate Per $100 of Assessed Value", shown in Table 14-E, I note the tax rate for 1978 and subsequent years is $2.86, compared with higher rates in 1976 and 1977. Will you please explain this?

A. Provisions were enacted into law during 1979, which changed the maximum Nevada tax rate from $5.00 per $100 of assessed value to $3.64 per $100 of assessed value. Our estimates reflect this change. The 1979 change in the law impacts the rate applicable to 1978 and subsequent years.

Q. Mr. Pignatelli, how does the California State Board of Equalization determine market value for the Company's properties in California?

A. The Board uses a "unitary" value approach. It determines the market value of the property the Company owns or uses within the State of California. Unitary assessed value is 25% of established unitary market value. In addition, certain properties of the Company are not part of the "unit". These are assessed separately and added to the unitary assessed value to determine total taxable assessed value. In developing market value, the Board takes into consideration, among other factors, historical cost less depreciation, capitalized earnings, stock and debt, and reproduction cost new less depreciation.

Q. Do the totals, as shown in Table 14-A, agree with the ad valorem taxes previously discussed, as shown in Tables 14-B through 14-E?

A. Yes, they do.

Q. Please indicate briefly the subject matter covered by Part II of Chapter 14.

A. Part . covers all taxes of the Company chargeable to California electric operations, except ad valorem taxes which were covered in Part I.

Q. Mr. Pignatelli, referring to Table 14-F of Chapter 14, will you please explain the computations made in determining the California Corporation Franchise Tax?

A. California Corporation Franchise Tax is computed on the basis of the operating revenues, expenses, and adjustments which are allowable or required by California law in computing taxable income. The tax is determined by multiplying the resultant taxable income by the existing tax rate.

Q. Will you please explain the adjustments you have made to the amount shown on line 7, "Net Operating Income Before Taxes Based on Income"?

A. The first item, "Liberalized Depreciation in Excess of Book Depreciation", reflects the difference between the depreciation which is allowed for California Corporation Franchise Tax purposes and that which is charged against operating income. The difference results primarily from the use of declining balance depreciation for tax and straight line remaining life method for book purposes. Additionally, for tax return purposes, the declining balance method of depreciation is utilized for nuclear fuel in the reactors. For operating income, the fuel is amortized over its life on a unit-of-production method for batches owned, and lease costs are charged to fuel expense for batches on financial leases.

"Interest Charges" are the allowable tax deductions for interest on outstanding bonds, debentures, and short-term debt applicable to electric operating income. That portion of debt interest applicable to Allowance for Funds Used During Construction (ADC) has been eliminated from total interest deductible in computing income taxes on utility operations for recorded years 1977 and 1978 and for estimated years 1979-1981. For recorded year 1976, interest on debt included in the computation of income tax on Other Income was based on the percent of nonoperative CWIP to total plant including CWIP. In 1977, the procedure for establishing the ADC rate was changed in conformity with new procedures established by the Federal Energy Regulatory Commission. The new procedure provides for the calculation of both the debt and equity components of ADC charged to construction work during the year. Consequently, for the years 1977-1981, the interest included in the computation of income taxes on Other Income was the interest component of the ADC charged to construction work orders during those years. This allocation is appropriate based on the fact that the Company's nonoperative CWIP is not in rate base. It would be inappropriate to provide the tax benefit of the interest deduction associated with plant which is not in rate base to the ratepayer who is neither paying for the facility nor carrying costs associated with the facility. Only when plant is placed in service and the ratepayer assumes the obligation of providing for the carrying costs through rate of return is it appropriate to flow the tax benefit associated with the interest deduction through to him.

Additionally, in order to make the Company whole, interest allocation is required because the Company employs a net ADC rate. It therefore capitalizes the carrying costs associated with construction work in progress at a rate which reflects the tax benefit resulting from the tax deduction of interest. As a result, the ratepayer pays a lesser amount in future periods, to cover plant depreciation, income taxes, and return, than he would if a gross ADC rate was used. If a utility employs a net ADC rate, as Edison does, and is prevented from allocating the tax benefit of the interest deduction to nonoperating income, then the ratepayer receives the tax benefit of the interest deduction twice. First, the ratepayer realizes the tax benefit in the year the interest expense is incurred and tax expense in cost of service is thus reduced, and secondly, he receives the benefit in all future periods when he only pays the net after tax ADC as a component of book depreciation. This is obviously an inappropriate result because the ratepayer receives, in total, a reduction in rates which exceeds the tax benefit which the utility actually recognizes on its tax returns.

"Removal Costs" represent the current deduction of the costs of dismantling, demolishing, or removing assets in the process of retirement. For book purposes, these costs are charged to the depreciation reserve. However, the income tax laws of both the Federal Government and the State of California permit the current deduction of these items.

"A&G Expense Capitalized" represents differences in amounts capitalized for book and tax purposes. These differences are the result of certain statutory deductions allowed for income tax purposes, the major item being pension costs.

"Taxes Capitalized" are use taxes, employer payroll taxes, and ad valorem taxes which have been capitalized as additional costs to property during construction but which are statutory deductions in the year incurred for tax purposes.

The "Ad Valorem Tax Adjustment" results from the fact that a deduction for the current year's lien date tax liability is allowable for tax purposes in the calendar year. On the books, with minor exceptions, one-half of the current year's lien date tax liability plus one-half of the previous year's lien date tax liability is charged against operating income. This adjustment is necessary because the fiscal year to which the lien date applies runs from July 1 to June 30.

"Energy Cost Adjustment Clause" reflects the adjustment necessary to reverse the net over/under collection recognized in operating income. For tax purposes, revenues are recognized as taxable income in the year billed; likewise, fuel and purchased power expenses are recognized in the year incurred. Consequently, the over/under collection adjustment to book income must be reversed to accurately reflect taxable income. In order to properly match income tax expense with book income, deferred tax accounting is utilized for the Energy Cost Adjustment Clause. The deferred taxes are calculated utilizing the effective 52.68% tax rate for years 1976-1978 and 50.86% for years 1979-1981.

The result of these adjustments, plus other miscellaneous adjustments, is a taxable income figure for California Corporation Franchise Tax. This taxable income is then subject to the statutory rate of 9.0% for years 1976-1979 and 9.6% for years 1980-1981. In addition, income taxes are paid as result of operations in Arizona, New Mexico, and Utah, but these are minor in amount.

Q. Mr. Pignatelli, will you please explain the Navajo Nation taxes to which the Company is exposed?

A. The Navajo Tribe of Indians has enacted three separate taxes to which the Company is exposed because of its ownership of facilities upon the Navajo Reservation and its purchased of fuel and energy from entities operating on the reservation. These taxes, the Sulfur Emission Tax, the Business

Activities Tax, and the Possessory Interest Tax all will impact the Company if ultimately held valid by the courts.

While no meaningful estimate of these taxes can as yet be made in terms of a dollar impact, the Company requests that the Commission consider these taxes and the potential for using a mechanism similar to the ECAC procedure to allow the Company to recover any costs which may affect operations in the test year.

Q. Please explain how you developed the Federal Income Tax figures which appear on Table 14-F.

A. The Federal Income Tax is computed by beginning with the taxable income for California Corporation Franchise Tax purposes and making additional adjustments which are applicable for Federal taxable income purposes only. A difference currently exists between the depreciation amount for California and Federal purposes. This results because liberalized depreciation was allowable for Federal purposes beginning in 1954 and for State of California purposes beginning in 1959 and because California has adopted different lives applicable to property placed in service after 1970 than those utilized under the Federal Asset Depreciation Range system. Additionally, California and Utah Corporation Franchise Taxes and Arizona and New Mexico Income Taxes are used as deductible items in computing Federal income tax. The adjustment for "Preferred Dividend Deduction" is allowable for Federal purposes only.

The result, after application of these adjustments, is "Taxable Income for Federal Income Tax". For years 1976-1978, the statutory Federal tax rate of 48%, allowing for the surtax exemption, and for years 1979-1981, the statutory Federal rate of 46%, allowing for the graduated rate benefit, are applied to the taxable income to develop the Federal tax liability. From the tax thus obtained, the "Investment Credit" is deducted leaving "Total Federal Income Tax". The Investment Credit reflected on Table 14-F utilizes current year flow-through with regard to the 4% credit subject to the Company's Section 46(e)(3) election. The additional 6% credit, subject to the Company's 1975 election of Section 46(f)(2), has been ratably flowed through based on the period of depreciation utilized for results of operations for the plant generating the credit. Additionally, no reduction to rate base has been made for the unamortized investment tax credit. This is consistent with the eligibility requirements of the Internal Revenue Code.

Q. Referring now to employer payroll taxes, Mr. Pignatelli, please explain how you have made your estimates for the years 1979-1981.

A. Employer payroll taxes consist of Federal Insurance Contribution Act Taxes and Federal Hospital Insurance Taxes, Federal Unemployment Tax Act Taxes, and State Unemployment Insurance Taxes. Estimates of these taxes for the years 1979-1981 are based on Federal and State statutes with respect to tax rates and taxable bases and estimates of the number of Company employees and their wages subject to such taxes.

Q. Mr. Pignatelli, insofar as the material contained in Chapter 14 is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as the material represents opinion, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Larry O. Chubb

Exhibit No. (SCE-2)______, Chapter 15

Q. Will you please state your name and address for the record?

A. Larry O. Chubb. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company?

A. I am Valuation Supervisor responsible for the Rate Base/Depreciation Division in that Company's Valuation Department.

Q. How long have you held that position?

A. Since February 1977.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Larry O. Chubb", does that portion of the exhibit accurately set forth your background, training, and experience?

A. Yes, it does.

Q. Are you testifying with respect to Chapters 15, 16, and 17 of Exhibit No. (SCE-2)______ for identification, entitled "Results of Operations"?

A. Yes, I am.

Q. Were those chapters prepared by you or under your supervision?

A. Yes.

Q. Turning now to Chapter 15, will you briefly indicate the development of the Company's Electric Plant Account 101?

A. The Company's Electric Plant in Service, Account 101, conforms with the Uniform System of Accounts as prescribed by the California Public Utilities Commission and the Federal Energy Regulatory Commission. The Company adopted this system in 1937 and has made modifications in accordance with revisions published through January 1, 1974.

Q. What other Electric Plant Accounts are associated with Account 101?

A. There are five others. Electric Plant Purchased or Sold, Account 102, is currently not active; Experimental Plant Unclassified, Account 103, was established to provide a separate identity for experimental or Research and Development type plant. The Company transferred the applicable amounts from Account 101 as of January 1, 1973, in accordance with Federal Energy Regulatory Commission Order No. 483. Account 103 is referenced in Chapter 16. Accounts 105, 106, and 107, Plant Held for Future Use, Completed Construction Not Classified, and Construction Work in Progress, respectively, are discussed in Chapter 17.

Q. Turning to Table 15-A, will you indicate briefly what that table reflects?

A. Table 15-A is a summary of the growth of Electric Plant in Service, Account 101, from 1976 through 1978. Balances at the beginning and end of each year, along with gross additions and retirements, are shown. Intangible and tangible plant are shown separately.

Q. Mr. Chubb, insofar as the material in Chapter 15 is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as the material represents opinion, does it reflect your best judgment?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Larry D. Chubb

Exhibit No. (SCE-2)______, Chapter 16

Q. Turning now to Chapter 16, entitled "Depreciation Expense and Reserve", was this material prepared by you or under your supervision?

A. It was.

Q. Please indicate briefly what Chapter 16 covers.

A. This chapter covers the depreciation expense and reserve for the recorded years 1976, 1977, and 1978, and estimated years 1979, 1980, and 1981.

Q. Will you briefly review the background of the method of depreciation used in preparing the estimates which are included in this chapter?

A. Depreciation expense is computed using accrual rates based on the straight line remaining life method in compliance with the Commission's Order in Decision No. 49665 on Application No. 33952. Decision No. 49665 included, as Appendix A, a copy of a memorandum of understanding reached by the Company and the Commission's staff which outlined the procedure to be used by the Company in its annual review and computation of depreciation expense. Since January 1, 1954, the Company has submitted its annual review of accrual rates and computation of depreciation expense to the Commission for review according to the procedures of the memorandum.

Q. In preparing the depreciation studies underlying the data in Chapter 16, what procedures have been followed?

A. The procedures outlined in the Commission's Standard Practice U-4 have been followed.

Q. Turning now to Table 16-A, will you indicate what that table shows?

A. Table 16-A shows the depreciation accruals charged to expense for the recorded years 1976, 1977, and 1978, and estimated years 1979, 1980, and 1981, plus an allocation of the accruals for common plant. Table 16-A also shows accruals for the other depreciable categories. In addition, the impact of San Onofre Nuclear Generating Station Unit No. 2 (SONGS 2) is indicated in Table 16-A. Column 6 includes the total 1981 accruals with both SONGS 1 and 2 in operation. Column 7 shows the accrual due to SONGS 2 only, while Column 8 shows the 1981 accruals without the inclusion of SONGS 2.

Q. Please indicate what Table 16-B shows.

A. Table 16-B shows the depreciation accrual rates for the estimated years 1979, 1980, and 1981. Rates shown for 1979 are the current accrual rates, adopted by the Commission in its Decision No. 89711 on Application No. 57602 for the test year 1979. The Company proposes to continue applying these rates for the estimated year 1980. The accrual rates for 1981 reflect the results of a current salvage study, an update of the 1977 detailed engineering estimate of decommissioning costs for nuclear generation, and the results of a review of average service lives and mortality characteristics for all accounts.

Q. Were the accrual rates shown in Table 16-B used to compute the depreciation expense shown in Table 16-A for estimated years 1979, 1980, and 1981, or were composite rates used?

A. Composite rates by class and subclass of plant, derived from the account rates shown in Table 16-B, were used to compute depreciation expense because forecasts of future plant are not made on a prime account basis.

Q. Turning now to Table 16-C, will you indicate what that table shows?

A. Table 16-C shows the computation of estimated 1981 annual depreciation rates by plant account on the straight line remaining life basis. It includes the following data by plant account: recorded gross plant in service as of January 1, 1979; estimated future net salvage in percent and amount; and recorded depreciation reserve as of January 1, 1979. These figures have been utilized in deriving the depreciable balances, by account, of plant book costs still to be depreciated over the remaining life of the property. The depreciable balance, by account, was divided by the estimated remaining life for the account to develop the annual accrual shown in Column 10. The annual accrual rate, Column 11, expressed as a percent of gross plant, is obtained by dividing Column 10 by Column 1, then multiplying the result by 100.

Q. What studies were made supporting the estimated future net salvage percentages for 1981?

A. Estimated future net salvage ratios for 1981 were developed after a complete review of all plant accounts. Following the procedure outlined in the Commission's Standard Practice U-4, a 10-year historical data base for retirements, gross salvage, and removal costs by plant account (excluding Nuclear Plant) was projected through test year 1981 using computerized trending techniques. Salvage ratios for each plant account were based on an analysis of these data and were expressed as a percent of plant retirements.

Q. What were the results of that study?

A. The study showed that the net salvage expected to be realized when plant facilities are retired has continued to decline in recent years. This is attributed primarily to the fact that labor costs to remove plant have generally risen more rapidly than have salvage values for material. The study thus demonstrated the need to make adjustments to our capital recovery rate for a number of accounts to reflect the change in net salvage.

Q. How were Nuclear Plant net salvage estimates developed for the proposed 1981 ratios?

A. Net salvage estimates for San Onofre Nuclear Generating Station Unit No. 1 (SONGS 1) were based on an update of the engineering study conducted by NUS Corporation in 1977 on nuclear decommissioning alternatives. The estimate for SONGS 2 was based upon preliminary findings in another study conducted by NUS Corporation to determine anticipated decommissioning costs for that unit. These findings indicate that the cost to decommission SONGS 2 will be approximately $65 million in 1979 dollars, of which Edison's share is estimated at $51.9 million.

Q. How does a change in net salvage affect the depreciation rate?

A. Net salvage is the amount received for materials less the labor cost to remove plant when it is retired from service. If the net salvage expected to be received at the time of plant retirement is large, less capital needs to be recovered each year, i.e., the depreciation rate can be lower. Conversely, if the anticipated net salvage is small, a higher depreciation rate is required to recover the original capital invested in plant. For many years, the labor cost of removing retired plant in a number of accounts has exceeded the material salvage, producing a negative net salvage which is recovered over the service life of the plant through an appropriately higher depreciation rate.

Q. Will you please tell us what studies were made supporting the estimated average service lives for 1981 and how these were made?

A. A review was made of the average service lives and dispersions for all accounts. Estimates of average service life and dispersion were made by one of three ways, all of which are prescribed in the Commission's Standard Practice U-4. First is the forecast method which is utilized where no significant retirement experience exists, such as is the case with large steam units. The forecast method is used for most of the production accounts. The second method used is judgment. This is used for those accounts where facts are known about the service life of an account beyond what computerized life analysis studies would indicate. The third method used involves the use of computer programs to simulate plant records. Three such simulation programs are utilized in our analyses. They are the simulated plant balances method (Bauhan method), and two simulated plant retirement methods (Garland and Brennan methods). These programs select the Iowa-type or H-type curve and average service life that most closely simulates the values of either plant balances or retirements at the end of specified periods. The result of these studies combined with what is known about the account and its recent history and near future are used to make an assessment of the average service life and curve type that best describes the account.

Q. What were the results of your life analysis study?

A. Our analysis indicated that while most accounts do not show significant enough trends to warrant changes in service life and/or dispersion, eleven accounts do warrant such a change. These changes have been reflected in the determination of accrual rates within this chapter. Specifically, ten accounts indicated a general lengthening of average service life and/or a shift towards lower mode curves. Only one account indicated a shortening of average service life. An increase in average service life will generally lead to an increase in remaining life which has the effect of reducing the accrual rate. The changes indicated as a result of the life analysis study for the ten accounts mentioned had the net effect of offsetting accrual rate increases that would otherwise have occurred due to the salvage study results.

Q. Will you please tell us now what is indicated on Table 16-D?

A. Table 16-D shows the depreciation reserve, by class and subclass of plant, for the recorded years 1976 through 1978 and estimated years 1979 through 1981. The weighted average reserves, shown on the bottom line of the table, are those used in computing rate base.

Q. Turning now to Table 16-E, will you indicate what that table shows?

A. Table 16-E is a summary of the depreciation reserve and the depreciation accruals for electric plant in service other than automotive, helicopters, garage equipment, tools and work equipment, power operated equipment, fuel transportation facilities, and experimental plant, as recorded for the years 1976 through 1978 and as estimated for the years 1979 through 1981. Also shown are composite depreciation rates for those same years, expressed in two ways: the accrual on beginning-of-year gross depreciable plant as a percentage of beginning-of-year gross depreciable plant, and the total year's accrual as a percentage of average gross depreciable plant for the year.

Q. Mr. Chubb, insofar as the material in Chapter 16 is of a factual nature, do you believe it to be accurate?

A. Yes, I do.

Q. Insofar as it represents opinion, does it represent your best judgment?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Larry O. Chubb

Exhibit No. (SCE-2)______, Chapter 17

Q. Mr. Chubb, you have previously testified herein?

A. Yes, I have.

Q. Are you also testifying with respect to Chapter 17, entitled "Rate Base", of Exhibit No. (SCE-2)______?

A. Yes.

Q. Please turn to Chapter 17 and briefly indicate what that chapter covers.

A. Rate base computations presented in this chapter have been developed on a weighted average original cost basis. Appropriate adjustments for average-year conditions are included. Recorded figures have been used, where applicable, for the years 1976 through 1978. Rate base for estimated years 1979, 1980, and 1981 has been developed from the most current budgeted plant additions data and estimated dates of completion that were available at the time this study was prepared.

Q. Turning now to Table 17-A, would you indicate briefly what that table shows?

A. Table 17-A summarizes System - Electric Rate Base developed for the years 1976 through 1981. Weighted average rate base totals are: $3.751 billion for 1976; $3.876 billion for 1977; $4.092 billion for 1978; $4.216 billion for 1979; $4.529 billion for 1980; and $5.381 billion for 1981. Table 17-A also shows separately the weighted average rate base for San Onofre Unit No. 2 (SONGS 2), assuming an operating date of July 1, 1981, in the amount of $573 million and an adjusted weighted rate base for the system excluding SONGS 2 for 1981, of $4.808 billion.

Q. Would you indicate briefly what the Fixed Capital component of rate base contains?

A. The Fixed Capital component of rate base is composed of Electric Plant in Service, Nuclear Fuel, Construction Work in Progress in Operation, and Property Held for Future Use. The Electric Plant element is comprised of Balance Sheet Accounts 101 and 103. The Nuclear Fuel element of Fixed Capital consists of Edison-owned nuclear fuel assemblies including accumulated amortization. Amounts receiving Allowance for Funds Used During Construction are excluded.

Construction Work in Progress in Operation for recorded years 1976, 1977, and 1978, and for estimated years 1979, 1980, and 1981, contains that portion of plant under construction which is complete and in operation and for which no calculation of Allowance for Funds Used During Construction, or ADC, is being made.

Property Held for Future Use is land obtained for future production, transmission, distribution, and general plant facilities. When distribution substation sites in this category will not be used for construction for three or more years after the rate base year under study, they are excluded. Property Held for Future Use, of course, does not receive ADC.

Added to these elements are Net Additions on a weighted average basis. The resultant sum comprises Total Fixed Capital.

Q. What adjustments were made to Fixed Capital?

A. Adjustments to Fixed Capital have been made in accordance with the Commission's rate-making practice. Reductions are made for "Customers' Advances for Construction" and, in accordance with FERC Order No. 490, "Contributions in Aid of Construction" were included with Electric Plant and offset in the Depreciation Reserve in appropriate amounts as of

January 1, 1974.

Q. What components comprise the "Working Capital" section?

A. The Working Capital section of rate base includes amounts required for Fuel Stock-Fossil, Material and Supplies, Fuel Prepayments, and Working Cash. The information used in developing figures for the Fuel Stock-Fossil category is based upon maintenance of a 90-day fuel supply and has been escalated to reflect 1980-1981 fuel cost estimates.

Q. What is the reason for including a Working Cash requirement in rate base?

A. A Working Cash requirement is included in the rate base so that investors may be compensated for that portion of the capital which they have supplied to cover the lag in collection of revenues over the lag in payment of bills for goods and services and other costs of operation and for which they would not otherwise be compensated.

Q. What is the basis used to develop Working Cash for the years 1976 through 1978?

A. Working Cash allowances are based on the method used by the California Public Utilities Commission staff in recent Edison rate proceedings. The average revenue lag has been developed from a computer analysis of the Company's recorded experience of lag in revenue collections by class. The average expense lags have been developed from the Company's recorded experience in paying its expenses. Working Cash computations for the year 1981 are set forth on Table 17-B.

Q. What was your source for the Depreciation Reserve amounts in Table 17-A?

A. The figures are obtained from Table 16-D of Chapter 16. These amounts are weighted averages.

Q. Would you briefly describe the remaining reserve deductions?

A. Along with Depreciation Reserve, deductions are also made in rate base for Taxes-Accelerated Amortization and Taxes Deferred-FERC Jurisdiction. Al..

deducted is the Unfunded Pension Reserve, which is that portion of the Company's pension liability to retired employees which is not separately funded.

Q. Mr. Chubb, insofar as the material in Chapter 17 is of a factual nature, do you believe it to be accurate?

A. Yes.

Q. Insofar as it represents opinion, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Rodney L. Larson

Exhibit No. (SCE-2)_____, Chapter 18

Q. Please state your name and address for the record.

A. My name is Rodney L. Larson, and my business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Southern California Edison Company?

A. Supervising Regulatory Cost Engineer.

Q. Please refer to Exhibit No. (SCE-3)_____ for identification entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Rodney L. Larson", does that portion of the exhibit accurately set forth your background, training, and experience?

A. Yes, it does.

Q. Are you testifying in connection with Chapter 18 of Exhibit No. (SCE-2)_____?

A. Yes, I am.

Q. Was the material prepared by you or under your supervision?

A. Yes, it was.

Q. Please indicate the purpose of your testimony relative to the material contained in Chapter 18, Mr. Larson.

A. The purpose of my testimony is to summarize the material that appears in detail in Chapters 7 through 17 by relating such results to the rate of return on rate base shown on the table identified as Table 18-A and to compare this result to the trend in return over the last ten years. It is intended that the discussion of this material will confirm the validity of Edison's showing; identify the impact of productivity; and introduce

The concept of attrition. Inadequate recognition of attrition has, in the past, been the major contributing factor casuing rates, as authorized, to yield a lower level of earnings than that found to be appropriate by past CPUC decisions. It should be kept in mind that the results here are for the total system and they will be translated into the California Public Utilities Commission jurisdiction in Chapter 19.

Q. Please turn to Table 18-A and explain what it demonstrates?

A. First it summarizes all the material previously presented in detail in Chapters 7 through 17 and expresses the resulting earned return on electric utility operations in relation to the rate base for each of the years. The result is referred to as the rate of return (ROR).

Q. What are the important results to be found on Table 18-A?

A. As shown, the return dollars increase by approximately $18 million from the 1976 base level of $298 million to the 1977 level of $316 million, reflecting increases in both retail and wholesale rates authorized in 1977. However, the 1977 return level of $316 million shows an increase of only a little over $4 million going from 1977 to 1978, the last year based on recorded information. Edison projects an expected increase of $74 million in return going from 1978 to 1979, but reductions of approximately $18 million in 1980, and another $9 million in 1981, excluding the effect of San Onofre, Unit 2 (SONGS 2). The need for an increase in base rates is reflected by the associated rate of return on rate base which drops from a projected high of 9.34% in 1979 to only 7.62% in 1981.

Q. You have indicated that the purpose of Table 18-A is a summary of the results of operations for the total system. Would you please explain what is shown on Chart 18-A?

A. Chart 18-A is a graph of the rate of return from the Results of Operations calculations, similar to that shown in Table 18-A, over the past ten years and includes the projections for 1979, 1980, and 1981.

Q. That chart appears to be a complex chart. Could you please being by explaining what the red and green lines represent?

A. The green line is a graph of the rate of return on rate base from the monthly Results of Operations reports as recorded and/or restated. The red line is based on the Results of Operations report information using the average-year concept employed for ratemaking purposes. Ratemaking adjustments are required when the accounting record is to be compared with a test year. Such adjustments are consistent with those made in the forecasted test year information, as for example, when a five year average is employed in establishing storm damage expenses. The heavy horizontal dark lines in the years 1969, 1972, 1973, 1976, and 1979 mark CPUC authorized level of rate of return for each of those years. For the years 1973 and 1976, these were determined to be the lower limit of that needed to provide the utility with a just and reasonable rate of return on its rate base to enable Edison to attract capital at reasonable cost and not impair its financial integrity.

The heavy dashed black line connecting the end of these lines defines an approximation of the level that might be considered the reasonable level in years between rate cases given the CPUC adopted test year rate of return criteria.

Q. Please indicate what the shaded area titled "Shortfall" represents.

A. This differential represents, in terms of a rate of return differential, the difference between what has been adopted by the CPUC as the reasonable rate of return level and that experienced or projected under existing rates.

Q. Please continue.

A. Turning to Table 18-A and recognizing that over the period shown, Company funding for conservation has been at a level explicitly covered in rates, and, therefore, comparisons from year to year should be considered without this component of cost. When this adjustment is made by eliminating lines 14 and 15, changes in year to year O&M expenses excluding fuel and purchased power costs are \$36.7, \$62.3, \$50.8, \$58.9, and \$33.3 million for 1976 through 1981. In other words, the increases in cost projected between 1979 to 1981 of \$92.2 million is actually less than the increases experienced on a recorded period between 1976 and 1978, which totals \$99.0 million. By adding up the O&M expenses, excluding fuel, purchased power and conservation, then dividing this total expense by the kWh sales in Chapter 7, it is possible to quantify the unit cost increases experienced and expected apart from the sales increase effect. The result is that these O&M expenses increased at a compound rate exceeding 10% between 1976 and 1978, while the same expenses are projected to increase at only slightly under 6% during the period 1979-1981. Jumping ahead to Chart 19-C, in Chapter 19, these same O&M expenses are shown to be increasing at a compound rate of 9.172% for the 1970-1978 period and 7.253% for the 1974-1978 period. In other words, the estimated expenses projected by Edison's O&M witnesses, when taken in total, reflect a significantly lower rate of escalation apart from the effect of sales growth than experienced in the recent past.

Q. What does such a result indicate to you?

A. I would say that, in total, Edison's estimates are conservative and reflect the desires and goals of its management relative to controlling costs. The projected over-all increase of under 6% for these selected O&M expenses in total is very low when compared to the assumed 7% wage increase and over-all inflation exceeding 7%. Such a low figure is possible only due to the inclusion of significant increases in productivity in the estimates for the test year.

Q. What should the Commission gain from careful consideration of this summary?

A. I would request that the Commission take notice of the fact that:

1. Edison's estimates in total appear to be very reasonable, in fact, even low.
2. Edison has consistently made a conservative showing in regards to O&M in past cases.

Therefore, any reductions to estimates that might be deemed reasonable through the cross examination of Edison's witnesses should in all probability be offset by equally logical increases in other areas. If the Commission allows only a one way street in considering adjustments to Edison's expenses and rate base they will only perpetuate the deficiencies that have resulted in past test years. Quantification of the total shortfall will be deferred to Chapters 19 and 20 where it can be expressed in terms of the California Public Utility Commission's jurisdiction.

Q. Chart 18-A does show a diagram in the projected period that appears to break this shortfall into components, would you please explain?

A. Both Chart 18-A and the associated text address shortfall in a conceptual basis. The components are illustrated and include a combination of:

1. Deficiencies in previous test years from Commission adopted levels of cost and revenue.
2. Attrition beyond the test year.
3. Regulatory lag.
4. Non-average year levels of expense.
5. Rate increases granted by the Commission or revenue differences resulting from changes in customer use patterns.
6. Productivity increases or decreases.

Q. What table or chart includes the detail of the projected or estimated part of this chart which extends beyond 1978?

A. This part of Chart 18-A is expanded to a larger scale in Chart 19-A for the CPUC jurisdiction.

Q. Please explain what you mean by deficiency.

A. As defined in the text accompanying Chart 18-A, it is the effect of all factors in a test year including regulatory lag which cause the rate of return to be different from that authorized by the regulatory agency. It is identified on the chart as the difference between the red ROR curve and the heavy dark line. In 1976, the displacement appears to be approximately 86 differential points in the ROR, while in 1979, it is projected to be somewhat less at 26 differential basis points.

Q. Could you please explain the reason for this displacement or deficiency as you refer to it?

A. Yes. The tables in the text on pages ____ and ____ compares test years 1976 and 1979 as adopted and as recorded (1976) and estimated for average ratemaking considerations (1979). Since 1979 is not yet recorded we have used our estimate in lieu of the recorded number. The difference between the adopted level of expenses and revenue demonstrates the optimism of the CPUC, an optimism that to some extent was shared by the Company at the time it made its own higher estimates. As shown for test year 1976, the adopted expenses excluding Fuel & Purchased Power and Income Taxes were low by approximately $43 million, while revenue for the CPUC jurisdiction was overestimated by approximately $40 million. At the same time, the rate base on a recorded basis was somewhat less than that used in developing authorized rates by $51 million.

Q. To what are these three errors attributed?

A. The primary reason that recorded revenue fell short of the adopted level in 1976 is that the final rate increase of $45 million was not granted by the CPUC until December of 1976, which guaranteed that the authorized rate of return could not be met in the test year. The expense estimates are more difficult to explain since at the time of the final decision, the CPUC had the advantage of knowing what the 12 months-ended expenses and rate base were as of October or November of 1976.

Q. Was the difference due to disallowances of certain expenses?

A. To a limited extent that is true, but the total of all exclusions amount to no more than $2 million.

Q. Could you make a similar analysis with respect to 1979?

A. Yes, although it should be remembered that the books are not yet closed for 1979. However, I have made a comparison using Edison's current estimate of 1979 expense, revenue, and rate base with that authorized in the latest Decision No. 89711. The results show that estimated 1979 revenue exceeds that adopted by the CPUC by approximately $38 million, that expenses excluding Fuel & Purchased Power and Income Taxes exceeded the level adopted by approximately $38 million, and rate base exceeded the adopted level by approximately $47 million.

Q. Can the sources of these differences be identified?

A. I believe that several contributing factors can be isolated. First, the revenue exceeded that estimated due in part to the non-tariff scheduled sales, especially those revenues which are described as Other Operating Revenues. Some of this was anticipated by the Commission in setting rates. The Commission reduced the revenue requirements by over $5 million due to higher levels of Other Operating Revenues which were attributed to the reconnection charge, etc. Other revenue effects are due primarily to more revenue being derived from the larger customers than anticipated. One additional revenue factor which has not been adjusted for is the Tax Adjustment Clause impact. By the beginning of 1979, there existed a negative balance in this account as a result of overcompensation in 1978. In order to balance this credit, the 1979 rate level was set higher than it would otherwise have been. The result is that part of the apparent additional revenue in 1979 is really to cover this previous expense component. Reasons for the expense shortfall is primarily due to the CPUC adopting the low expense estimates of the CPUC staff. A similar explanation applies to the rate base estimate.

Q. Mr. Larson, what conclusion do you draw from this analysis and you experience with previous rate cases?

A. I believe they show that Edison has been conservative with respect to expectations of future levels of expense and rate base, yet the CPuC has continued to trim even these conservative estimates which results in the inevitable inability of the Company to achieve the authorized rate of return in the test year. Even if the Company's estimates had been adopted, the rates authorized would have resulted in under-recovery of the cost of service in the test year but the resulting deficiency would have been less. In the years following the test year, additional attrition resulting from inflation seriously aggravates an already difficult situation, with the result that it is practically impossible for the Company to achieve the authorized rate of return under the procedure presently used for setting rate levels.

Q. Mr. Larson, prior witnesses covering Chapter 7 through 17 have mentioned the various productivity programs and efforts that have been taken into account in making their estimates, would not these programs offset the attrition somewhat?

A. Yes, they reduce the effect of attrition to a level lower than would otherwise occur except for Edison's continued efforts in serving its customers more efficiently within the constraints set by regulatory agencies exercising jurisdiction over various aspects of Edison's operations.

Q. Would you recap the effect of the over-all productivity effort?

A. When the operating expenses are viewed on a per unit (kWh) output basis, the effect of productivity can be seen. In all cases, with the exception of certain production expenses, the unit costs from 1976 through 1981 show an upward slope of the general productivity index.

Q. Would you please explain what a "general productivity index" is?

A. Reduced cost per unit output reflects increased productivity, however, rather than use the decrease directly as indicative of the effectiveness of productivity, it was determined that confusion would be reduced by associating a positive or upward sloping function with productivity, therefore an index which is simply the inverse of the unit cost function was used. In other words, an increase in the general productivity index means increased productivity and a decrease in the index would mean that productivity is decreasing.

Q. Can you list the index results for the various components of expense, please?

A. Yes, from Table 18-B, Production shows an over-all decrease of 2.18% per year in the index; Transmission a 6.69% increase; Distribution a 4.65% increase; Customer Accounts a 1.31% increase; Administrative and General a 3.05% increase in the productivity index.

Q. Would you please explain the apparent loss in productivity in the area of production?

A. Many factors contribute to such a result, including the fact that due to deferrals of new capacity, older units are being called on to provide capacity at a correspondingly higher cost. Also, programs aimed at increasing the capacity factor of the more cost efficient fuel units result in savings in the fuel area but at a cost of higher maintenance in the short run.

Q. Table 18-B delineates the general productivity index by components of labor and the remaining portion of the expense. Could you explain what conclusions can be reached based on that table?

A. The labor productivity as measured by the general productivity index exceeds 3% per year and is even higher in the test years which explains the reason for the low escalation in over-all costs included in this showing?

Q. Is the general productivity index all that is needed to demonstrate the effectiveness of Edison's productivity effort?

A. No. Testimony by previous witnesses indicates the planning of specific programs aimed at improving productivity and the testimony of Mr. Horton underscores the commitment of Edison's management to the effort of productivity improvement.

Q. Mr. Larson, insofar as the material contained in Chapter 18 is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as the material represents opinion, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Rodney L. Larson

Exhibit No. (SCE-2)_____, Chapter 19, Parts I - III

Q. Please state your full name for the record.

A. My name is Rodney L. Larson

Q. Mr. Larson have you previously testified in this proceeding?

A. Yes, I have.

Q. Mr. Larson, are you also testifying with respect to Parts I, II, and III of Chapter 19 of Exhibit No. (SCE-2)_____ for identification?

A. Yes.

Q. Directing your attention now to Chapter 19 of Exhibit No. (SCE-2)____ were Parts I-III of that chapter prepared by your or under your supervision?

A. They were.

Q. Please briefly indicate what Part I of Chapter 19 shows.

A. Part I develops first the cost allocation between FERC and CPUC jurisdictions and then continues a more detailed allocation of the CPUC jurisdictional costs to the six retail customer groups. The jurisdictional separation including ECAC related revenues and expenses is summarized on Table 19-A, Sheet 1 of 2. Table 19-A, Sheet 2 of 2 summarizes the jurisdictional separation excluding related ECAC revenues and expenses. The six customer group allocation is summarized on Table 19-B, Sheets 1 through 4. Sheets 1 of 4 and 3 of 4 include ECAC related revenues and expenses while Sheets 2 of 4 and 4 of 4 exclude these revenues and expenses. Table 19-A, Sheet 1 of 2, begins with the estimated revenues, expenses and rate base for the test year 1981, shown in Table 18-A, Sheet 1 of 2, Column 8. Before an allocation of costs can be made to resale and the six CPUC retail customer groups, it is necessary to exclude from system total the costs of facilities, revenues, and expenses associated with non-customer group service.

Q. What comprises the non-customer group service?

A. Basically, these are contract, interchange, nonelectric service revenues, and certain special rate schedules.

Q. What special rate schedules are you referring to?

A. Fringe accounts and service to Catalina Island.

Q. Will you please explain what is contained in Column 3, Pacific Intertie?

A. The Pacific Intertie, as far as Edison is concerned, is the transmission system used to transmit energy between the Pacific Northwest and the Edison system. The Pacific Intertie is made up of two 500 kV AC lines and one 800 kV DC line from the Pacific Northwest. In addition to transmitting power to and from the Edison system for the benefit of Edison's customers, the two AC lines are used to provide EHV transmission service to the United States Bureau of Reclamation and the State of California Department of Water Resources. The figures appearing in Column 3 are Edison's portion of the Pacific Intertie revenues, costs, and rate base items that are allocated to such public agencies' transmission service under the Company's EHV contract with these public agencies. As shown in this column, the rate of return is projected to be 4.48% for test year 1981. This represents a deficiency of approximately $1.1 million in revenue requirements given the requested rate of return of 11.18%. This deficiency represents unrecoverable costs borne by Edison's shareholders.

Q. Will you please explain the next four columns?

A. Column 4, labeled "Other Electric Revenue", consists of revenue-producing assets which do not involve the sale of electric energy. Such items would include, among others, added facility revenue, joint pole rentals, service establishment charges, and rentals of Edison transmission rights-of-way. The rate of return on these facilities is assumed to be equal to the rate of return on the total system, excluding Santa Catalina Island.

Columns 5 through 7 involve the sale of electric energy under various contracts. These would include the State Water Plan and Fringe contracts. The revenues from these contracts are used as a direct offset to system costs.

Q. How is the cost allocation between jurisdictions made?

A. First, the Total To Be Allocated, Column 8, is calculated by subtracting Columns 2 through 7 from Column 1.

Second, the amounts in this column are then assigned to the following two systems: the Power Pool System, which is further classified into Commodity - Column 9, and Demand - Column 10, and the Distributing System - Column 11. The Power Pool System consists of expense and rate base related to all generation, including fuel handling facilities, and all transmission facilities down to and including 66 kV lines. Such expense items would include fuel and purchased power costs, operation and maintenance costs related to production and transmission facilities, and all associated overhead items, namely, depreciation, taxes, and return related to production and transmission facilities. The Distributing System includes all facilities below 66 kV. Such expense items would include the operation and maintenance accounts for Distribution, Customer Accounts, and Customer Service and Informational, and all associated overhead items related to distribution facilities. There is an allocation to both the Power Pool and Distributing Systems of costs related to Rate Base - General, Rate Base - Working Capital, Depreciation - General, Misc. Taxes - Other, and Administrative and General expenses.

Q. How is the classification of Power Pool System costs determined in Columns 9 (Commodity) and 10 (Demand)?

A. The first component, Commodity, is made up of 100% of the Production - Fuel expense, that portion of the Purchased Power expense computed by the energy charge, and certain items from the Production - Other expense, as explained below. Fifty-two percent of all Hydro costs are assigned to Commodity, including Hydro Operation and Maintenance expense, Administrative and General expense, Depreciation, Ad Valorem Taxes, Income Taxes, Return, and the Rate Base associated with Hydro. The 52% factor applied to Hydro has been developed from the ratio of kilowatthours produced under adverse-year conditions to the kilowatthours produced under average-year conditions.

Also included in Commodity are 50% of Steam Account 510 (Maintenance supervision and engineering) and 100% of Steam Accounts 512 (Maintenance of boiler plant), 513 (Maintenance of electric plant), and 514 (Maintenance of miscellaneous steam plant). In like manner, included in Commodity are 50% of Nuclear Account 528 (Maintenance supervision and engineering) and 100% of Nuclear Accounts 530 (Maintenance of reactor plant), 531 (Maintenance of electric plant), and 532 (Maintenance of miscellaneous nuclear plant).

Q. Are there some specific facilities allocated to Commodity?

A. Yes. Costs associated with Fossil Fuel Handling Facilities including the fuel oil transportation and storage system and the coal and ash handling facilities, are assigned to Commodity. These costs include the allocated portion of Administrative and General expense, Depreciation, Ad Valorem Taxes, Income Taxes, Return, and the Rate Base

Q. What costs are classified as Power Pool System - Demand, Column 10?

A. The remainder of all Production - Other expense; Purchased Power expense; Production rate base; all Transmission expense and rate base; and the associated overhead items (namely, Administrative and General, Depreciation, and Taxes - Other) related to the above mentioned Production and Transmission rate base.

Q. What costs are included in Column 11, the Distributing System column?

A. The Distributing System includes all O&M and associated overhead costs related to Distribution rate base together with the operating expense accounts for Customer Accounts, and Customer Service and Informational. In addition, there is an allocation to the Distributing System, portions of Rate Base - General, Rate Base - Working Capital, Depreciation - General, Misc. Taxes - Other, and Administrative and General Expenses.

Q. How were Income Tax and Return allocated?

A. Income Tax and Return were first allocated to Power Pool and Distributing System in proportion to rate base, for system total, excluding Santa Catalina Island. Noncustomer group income tax and return were then subtracted from the totals to arrive at the income tax and return for Power Pool System, Column 9 and Column 10, and for Distributing System, Column 11.

Q. What is the next step in the cost allocation procedure?

A. After the total to be allocated to customer groups is assigned to Commodity, Demand, and Distributing System, all Commodity costs, Column 9, are allocated between Resale and Other Than Resale on the basis of the ratio of the annual kilowatthours at Power Pool level of each to the total Resale and Other Than Resale kilowatthours at power pool level. It is estimated that for 1981, Resale will account for 7.153% of the total sales at Power Pool level.

Q. How were Demand costs allocated?

A. Demand costs, Column 10, have been allocated between Resale and Other Than Resale on the basis of a 12-month weighted average peak responsibility method. Recorded data for 1972 through 1978 was available for defining the contribution of resale at the time of the monthly system peaks. Based on a linear regression of recorded data, a percentage of Resale to total net main system was developed at the Power Pool level of demand for the estimated year. In this study, it is estimated that Resale will account for 7.882% of the demand at the Power Pool level in 1981.

Q. What adjustments have you made to this power pool cost of service procedure that warrant further explanation?

A. As I have previously noted, the Power Pool system extends to the end of the 66 kV voltage level. In the past, there has not been significant sales to customers above that level; however, currently there are significant resale sales at the 220 kV level, which warrant an adjustment to our previous cost of service procedure. The adjustment is needed to correctly allocate 66 kV facilities to wholesale and retail sales. In 1981, the adjustment requires a transfer of approximately $8 million worth of rate base out of the resale cost of service into the retail cost of service. In addition, O & M and overhead costs related to the $8 million rate base have been transferred.

Q. How were the Distributing System costs allocated?

A. Primarily, the cost of the Distributing System allocated to Resale has been a direct assignment of costs associated with the Distribution facilities used to serve the Resale customers.

Q. How are the totals for each jurisdiction developed?

A. The summation of the Commodity, Demand, and Distributing System allocations to Resale appears in Table 19-A, Column 12, and To Other Than Resale in Column 13.

The Jurisdiction totals are the accumulation of prior allocations. The FERC Jurisdiction Total, Column 14 of Table 19-A, is made up of Pacific Intertie - Column 3, Pooling Contracts - FERC - Column 7, and To Resale - Column 12. The CPUC Jurisdiction Total, Column 15, is made up of Santa Catalina Island - Column 2, Other Electric Revenues - Column 4, Fringe - Column 5, Pooling Contracts - CPUC - Column 6, and To

Other Than Resale - Column 13.

Q. Mr. Larson, please describe what is shown in Table 19-A, Sheet 2 of 2.

A. Table 19-A, Sheet 2 of 2, shows the jurisdictional separation excluding ECAC revenues and expenses. As shown in Column 1, Operating Revenues have been adjusted for the removal of approximately $2.5 billion in ECAC revenues. In addition, fuel and purchased power expense, uncollectibles, and franchise fees have been adjusted to reflect this revenue loss. Fringe (Column 5) has also been adjusted to exclude all related ECAC revenues and expenses.

Since ECAC is not applied to resale, all adjustments were made To Other Than Resale and CPUC Jurisdiction (Column 13 and 15).

Q. Turning now to Table 19-B of Chapter 19, Cost Allocation Between Customer Groups, would you briefly describe that information?

A. Table 19-B is the allocation of costs to the six customer groups under the jurisdiction of the California Public Utilities Commission. The summary of that allocation is found on Table 19-B, Sheets 1 through 4.

Q. Please describe what is shown in Table 19-B, Sheet 1.

A. Table 19-B, Sheet 1 of 4 shows the allocation of Other Than Resale costs (including ECAC revenue and expense) under the present retail customer groupings, which consist of Domestic; Lighting and Small Power; Large Power customers with demands between 200 - 1,000 kW; the TOU customer group with demands of 1,000 kW and above; Agriculture and Pumping, and Street Lighting. The Total To Be Allocated - Column 1, is the same as To Other Than Resale - Column 13, in Table 19-A, Sheet 1 of 2. The allocations of classified costs in Table 19-A, Sheet 1 of 2, To Other Than Resale becomes the basis of the cost allocation to the six customer groups. The six customer group portion of the Power Pool System classified as Commodity is allocated to the customers' group on an energy or kilowatthour basis. The six customer group portion of the Power Pool System classified as Demand is allocated to the customer groups on a 12-month weighted average peak responsibility method. Distributing System costs and rate base were allocated to Commodity, Demand, and Customer components based on both prior allocation of costs and direct studies which weight the number of customers among customer groups.

Q. What does Table 19-B, Sheet 2 of 4 show?

A. Table 19-B, Sheet 2 of 4, shows the allocation of the Other Than Resale costs under the present retail customer groupings, modified to remove all ECAC revenues and expenses. The Total To Be Allocated, Column 1, is the same as To Other Than Resale - Column 13, in Table 19-A, Sheet 2 of 2.

Q. What does Table 19-B, Sheet 3 of 4 show?

A. Table 19-B, Sheet 3 of 4, shows the allocation of Other Than Resale costs (including ECAC revenue and expense) under the proposed retail customer groupings. The difference between the proposed and present retail customer groupings is that the TOU customer group is proposed to contain customers with 500 kW demands and above, instead of 1,000 kW demands under present customer groups. Commensurate with this, the Large Power customer group contains customers with demands from 200 - 500 kW under proposed customer groups instead of 200 - 1,000 kW under present customer groupings. There is also a slight shift of Agricultural and Pumping customers with demands of 500 kW and above into the TOU customer group under the proposed scheme.

Q. Please describe Table 19-B, Sheet 4 of 4.

A. Table 19-B, Sheet 4 of 4, shows the allocation of Other Than Resale costs under the proposed retail customer groupings, modified to removal all ECAC revenues and expenses. The cost allocation methodology is the same as that used in the previous tables.

Q. What results do you obtain from the cost allocation study shown in Table 19-B, Sheet 1 of 4?

A. Under presently effective tariffs for present customer groups at the estimated level of sales, revenues, expenses, and rate base estimated or the test year 1981, the over-all composite rate of return for the six customer groups under California Public Utilities Commission jurisdiction would be about 7.6%.

Considered individually, the rate of return for the customer groups as shown in the table would be: Domestic, 1.9%; Lighting and Small Power, 13.2%; Large Power, 10.0%; TOU, 15.3%; Agricultural and Pumping, 7.7%; and Street Lighting, 4.7%.

Q. What results do you obtain from the cost allocation study shown in Table 19-B, Sheet 2 of 4?

A. Under both the presently effective tariffs excluding ECAC revenues and expenses, the present customer groups, the estimated level of sales, and rate base for the test year 1981, the over-all composite rate of return for the six customer groups under California Public Utilities Commission jurisdiction remained about 7.6%.

Considered individually, the rate of return for the customer groups as shown in the table would be about: Domestic, 4.3%; Lighting and Small Power, 12.2%; Large Power, 8.2%; TOU, 11.4%; Agricultural and Pumping, 6.5%; and Street Lighting, 4.7%.

Q. What results do you obtain from the cost allocation study shown in Table 19-B, Sheet 3 of 4?

A. Under presently effective tariffs using the proposed customer groups, the rates of return for the six customer groups are approximately as follows: Domestic, 1.9%; Lighting and Small Power, 13.2%; Large Power, 9.1%; TOU, 14.3%; Agricultural and Pumping, 7.7%; and Street Lighting, 4.7%. Under the proposed rates contained within this filing, the rates of return are approximately as follows: Domestic, 5.6%; Lighting and Small Power, 18.0%; Large Power, 13.2%; TOU, 16.5%; Agricultural and Pumping, 12.5%; and Street Lighting, 8.0%.

Q. What results do you obtain from the cost allocation study shown in Table 19-B, Sheet 4 of 4?

A. Under both the presently effective tariffs excluding ECAC revenues and expenses and proposed customer groups, the rates of return for the six customer groups are approximately as follows: Domestic, 4.3%; Lighting and Small Power, 12.2%; Large Power, 7.5%; TOU, 10.9%; Agricultural and Pumping, 6.5%; and Street Lighting, 4.7%. Under the proposed rates contained within this filing, the rates of return are approximately as follows: Domestic, 8.0%; Lighting and Small Power, 17.0%; Large Power, 11.5%; TOU, 13.1%; Agricultural and Pumping, 11.3%; and Street Lighting, 8.0%.

Q. The rate of return by group varies significantly between the calculation at the total cost level and that with ECAC revenues and expenses removed. To what is this difference attributed?

A. The difference is the result of the mismatch of ECAC revenues and expenses at the customer level. Since Domestic lifeline customers are subsidized in their ECAC billings, the spread of ECAC expenses and ECAC revenues to all customer groups do not balance by customer group. In addition, ECAC treats all customers as though they received energy at the same voltage level. If one customer takes service at 66 kV while another at 220 kV, this treatment causes the first customer to subsidize in part, the losses for the low voltage customers. These two factors combine to increase the rate of return to non-lifeline customers and reduce the rate of return to lifeline and the Domestic group in total.

Q. Would you briefly indicate the need and the application of the Net-To-Gross

Multiplier?

A. In developing the gross revenue increase needed to develop a specific rate of return, the first step is to develop the required net revenue increase which is determined by subtracting the return amount at present rates from the return amount required to obtain the target rate of return. The target rate of return is equal to the cost of money plus the attrition allowance factor of 0.4%, and the net revenue is developed by multiplying the rate base by the target ROR. The next step is to develop the gross revenue increase needed to produce this net revenue increase, considering incremental taxes, franchise fees, and uncollectibles. This is accomplished by use of a net-to-gross multiplier. The development of this factor is shown in the text in Chapter 19.

Q. Turning now to Part III of Chapter 19, would you describe its contents?

A. Part III of Chapter 19, graphically and editorially describes the rate of return shortfall the Company has experienced over the recorded years 1966 through 1978 (See Chart 19-A), and estimated into 1979 through 1981. The two major reasons for this shortfall is what I have called deficiency and attrition. Deficiency is defined as both an over-estimate, by the Commission, of the Company's test year earnings at existing rates and the result of untimely Commission decisions (regulatory lag). The Commission has recognized regulatory lag and has formulated a regulatory lag plan which will help offset part of the deficiency. On the other hand, the Commission has persisted in overstating the Company's test year earnings at existing rates, thereby, perpetuating the deficiency problem. The Commission could help alleviate this problem by recognizing the fact, that from an historical perspective, even the Company's test year estimates of earnings at existing rates have tended to overstate such earnings and, thereby, give greater weight to the Company's Results of Operation's estimates.

Q. Turning to the second component, which you referred to earlier as attrition, to what do you attribute th s impact?

A. Attrition results from increases in financing costs, expenses, and rate base beyond the test year not accompanied by offsetting revenue increases sufficient to allow the Company to earn it's authorized rate of return on rate base. Attrition is primarily the direct result of factors beyond the control of the Company. Such factors would include; the effect of general inflation, additions to rate base which reflect both inflation and increased environmental costs, increased regulatory costs, and increased embedded costs of senior capital made necessary by both inflation in capital costs and the need to finance additional capital additions to enable the company to satisfy the increasing energy requirements of the public. Such costs are offset somewhat by productivity increases. Both attrition and deficiency are graphically illustrated on Chart 19-B. This chart shows that out of the Company's total request of $340.2 million, $18.9 million was the result of the 1979 test year deficiency and $226.4 million was due to attrition. Out of the total attrition amount, $171.4 million was due to operational attrition and $55.0 million was due to financial attrition. To overcome the impact of attrition in the year beyond the test year 1981, we have included an attrition allowance to be added to the Company's total request for rate relief which is in addition to the 15.0% Return on Common Equity requested for test year 1981.

Q. What is the basis for such an attrition allowance?

A. The attrition allowance was calculated based on 9 years of recorded CPUC jurisdictional cost data (1970-1978). Unit cost (mills/kWh) trends were calculated for two different periods, namely, 1970-1978 and 1974-1978. Specific trends were calculated for (1) O&M expenses, excluding fuel, purchased power, and customer service and informational expenses, (2) depreciation expense, (3) taxes - other expense, and (4) rate base. Fuel and purchased power expenses were excluded from the attrition allowance because they are essentially recovered through ECAC although a component of approximately $26 million is not covered by ECAC. Customer service and informational expenses were eliminated because it was felt that for this type of expense item, costs incurred beyond the test year would be a function of what the Commission authorizes in the test year.

Q. Mr. Larson, you indicated that you used unit costs instead of total dollars in calculating the various trend rates, what was the reasoning behind this?

A. Unit costs (per kWh) were trended instead of total dollar figures so that attrition could be analyzed apart from the impact from the rate of increase in kWh sales and revenues resulting from increased kWh sales. It should be noted that a productivity component is incorporated in the attrition allowance since productivity gains are included in the recorded costs (1970-1978). The 9-year CPUC jurisdictional unit cost data and the calculated annual trend rates are shown in Chart 19-C.

Q. How are the attrition factors calculated?

A. First, the historical annual trend rates shown in Chart 19-C for O&M expenses, depreciation expense, and taxes-other expense have been applied to the corresponding estimated unit cost data shown for test year 1981 to estimate the projected annual change in these expense items beyond the test year. 0.1 minus the effective incremental tax rate is then applied to those expense items deductible for income tax purposes to arrive at the effective after-tax annual incremental change in return. When this incremental change in return is subtracted from the requested return and divided by the test year 1981 rate base, the resultant impact on rate of return on rate base can be determined. This resultant rate of return is then subtracted from the requested rate of return to derive the attrition factor. The attrition factors for the aforementioned expense items are shown on page _____ of SCE-2_____. Detailed calculations are shown in Appendix A attached to my testimony.

Q. How was attrition calculated for rate base?

A. Attrition associated with rate base was calculated in the same manner as expense, with the exception that attrition was offset somewhat by including the effect of increased interest deductions related to increases in rate base. Specifically, the attrition caused by rate base is calculated by applying the trend rate to the test year rate base in order to derive the annual change in rate base. The test year return is then divided into components, the first of which is related to the test year rate base while the second is due to the incremental change in rate base to derive the impact on rate of return caused by the incremental change in rate base. This impact is offset somewhat by including the interest deduction related to changes in rate base. This resultant impact on rate of return is then subtracted from the requested rate of return to derive the attrition factor. The rate base attrition factor for the 1970-1978 period was 0.28% and for the 1974-1978 period was -0.05%. These calculations are also shown in Appendix A attached to my testimony.

Q. Mr. Larson, there appears to be a wide discrepancy in the rate base attrition factor calculated for these two time periods. What, in your opinion, are the reasons for this?

A. The 1974-1978 rate base attrition factor was influenced by a reduced rate of increase in plant expenditures and by increased depreciation rates. On the other hand, the 1970-1978 period reflects both the 1974-1978 period and the pre-1974 period, which was marked by a higher rate of plant expenditure increases. Future rate base trends beyond the test year would, in my opinion, be higher than both periods given the impact of San Onofre on future rate base calculations. The 1970-1978 period provides the better "fit" in the trend analysis.

Q. You mentioned earlier that attrition includes increased financing costs. What amount of attrition have you included in the attrition allowance related to financing costs?

A. I have included in the attrition allowance 15 basis points for increased financing costs, which is the recommendation provided in Mr. Christie's testimony.

Q. Would you please summarize your attrition allowance recommendation?

A. Yes. The calculated annual attrition factors are summarized below:

	Time Period	
Source of Attrition	1970-1978	1974-1978
O&M Expenses	0.54%	0.43%
Depreciation Expense	0.11%	0.10%
Taxes-Other Expense	0.02%	0.04%
Rate Base	0.28%	(0.05%)
Subtotal	0.95%	0.52%
Financing Costs	0.15%	0.15%
Total	1.10%	0.67%

The large discrepancy between these two period is largely the result of rate base. As discussed previously the 1970-1978 period is a better representation of the attrition factor associated with rate base, however, to be on the conservative side, an average of these two time periods results in an annual attrition allowance, excluding financing costs, of 0.735%. The averaging of these two time periods results in very little attrition being associated with rate base. The effect of this procedure is to eliminate the future impact of San Onofre in the requested attrition allowance for rate base. The 0.735% attrition allowance can be compared to the estimated attrition in CPUC jurisdictional rate of return between the estimated period 1979-1981 of 0.885% (1.77% ÷ 2). Adding the financial attrition of 0.15% to both these numbers results in a calculated attrition allowance based on historical costs of 0.885%, and an attrition allowance based on estimated costs between the 1979-1981 period of 1.035%. An annual attrition allowance of 0.8% is recommended and as shown from the previous analysis is certainly conservative.

Q. Mr. Larson, how would this recommended annual allowance for attrition be included in the Company's increased rate request before this Commission?

A. Given the policy of this Commission (CPUC Decision No. 89711, Pages 129-130), that base rate increase requests should occur at a minimum of two year intervals, for the Company to be allowed to earn its authorized rate of return during this two year interval, the Company would have to be allowed to increase its rates by 38.0 million or, by 0.4% rate of return on rate base in the test year. This is because in the year following the test year the Company's return on rate base would be expected to decrease by approximately 0.8% due to attrition. The Company, therefore, would earn at a level of 0.4% rate of return on rate base above the 1981 test year cost of capital and at a rate of return level of 0.4% below the test year cost of capital in the year following the test year. The net result would be that the Company, over this two year interval, would be realistically afforded the opportunity to earn the authorized rate of return on rate base.

Q. Mr. Larson, insofar as the material in Parts I, II, and III of Chapter 19 of Exhibit No. (SCE-3)______ is factual in nature, do you believe it to be accurate?

A. Yes, I do.
Q. And insofar as it represents opinion, does it reflect your best judgment?
A. Yes, it does.
Q. Does this conclude your prepared testimony?
A. Yes, it does.

OPERATIONAL ATTRITION CALCULATIONS

1. Formulas: $AF(x) = ROR - \dfrac{(ROR)\ (RB \text{ Per kWh}) - (x \text{ Per kWh})\ (Ax\%)\ (1 - t)}{RB \text{ Per kWh}}$

$$AF(RB) = ROR - \frac{(ROR)\ (RB \text{ Per kWh}) + RB\ (A_{RB}\%)\ (\text{Debt Ratio})\ (\text{Debt Cost})\ (t)}{RB + RB\ (A_{RB}\%)}$$

Where: AF(x) = Attrition factor for (1) Expense, excluding Fuel, Purchased Power, CS&I, and Taxes - (E), (2) Depreciation-(Depr.), (3) Taxes-Other, (T-O).

AF(RB) = Attrition Factor For Rate Base

ROR = Rate of Return

RB = Rate Base

x = Attrition items mentioned under AF(x)

Ax% = Annual Trend Rate For Expense

t = Combined Tax Rate = .51184

$A_{RB}\%$ = Annual Trend Rate For Rate Base

Debt Ratio = 47%

Debt Cost = 9.75%

OPERATIONAL ATTRITION CALCULATIONS

II. Calculations:

A. 1970-1978 Trended Data

(1) $AF(E) = 10.78\% - \frac{(10.78\%)\ (76.092) - (9.124)\ (9.172\%)\ (1 - .51184)}{76.092}$

$AF(E) = 10.78\% - 10.24\% = 0.54\%$

(2) $AF(DEPR) = 10.78\% - \frac{(10.78\%\ \ (76.092) - (3.309)\ (4.972\%)\ (1 - .51184)}{76.092}$

$AF(DEPR) = 10.78\% - 10.67\% = 0.11\%$

(3) $AF(T\text{-}O) = 10.78\% - \frac{(10.78\%)\ (76.092) - (1.207)\ (2.113\%)\ (1 - .51184)}{76.092}$

$AF(T\text{-}O) = 10.78\% - 10.76\% = 0.02\%$

(4) $AF(RB) = 10.78\% - \frac{(10.78\%)\ (76.092) + (76.092)\ (3.483\%)\ (47\%)\ (9.75\%)\ (.51184)}{76.092 + (76.092\ \ (3.483\%)\ )}$

$AF(RB) = 10.78\% - 10.50\% = 0.28\%$

Summary	
AF(E)	0.54%
AF(DEPR)	0.11%
AF(T-O)	0.02%
AF(RB)	0.28%
Total	0.95%

OPERATIONAL ATTRITION CALCULATIONS

B. 1974-1978 Trended Data

(1) $AF(E) = 10.78\% - \dfrac{(10.78\% \; (76.092) - (9.124)\;(7.253\%)\;(1 - .51184)}{76.092}$

$AF(E) = 10.78\% - 10.35\% = 0.43\%$

(2) $AF(DEPR) = 10.78\% - \dfrac{(10.78\% \; (76.092) - (3.309)\;(4.547\%)\;(1 - .51184)}{76.092}$

$AF(DEPR) = 10.78\% - 10.68\% = 0.10\%$

(3) $AF(T\text{-}O) = 10.78\% - \dfrac{(10.78\% \; (76.092) - (1.207)\;(4.679\%)\;(1 - .51184)}{76.092}$

$AF(T\text{-}O) = 10.78\% - 10.74\% = 0.04\%$

(4) $AF(RB) = 10.78\% - \dfrac{(10.78\% \; (76.092) + (76.092)\;(- .543\%)\;(47\%)\;(9.75\%)\;(.51184)}{76.092 + (76.092)\;(- .543\%)}$

$AF(RB) = 10.78\% - 10.83\% = (0.05\%)$

Summary	
AF(E)	0.43%
AF(DEPR)	0.10%
AF(T-O)	0.04%
AF(RB)	(0.05%)
Total	0.52%

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Warren E. Ferguson

Exhibit No. (SCE-2)_____, Chapter 19 (Parts IV - VI)

Q. Please state your full name.

A. My name is Warren E. Ferguson.

Q. Mr. Ferguson, have you previously testified in this proceeding?

A. Yes, I have.

Q. Were Appendices B, C, and F to the application prepared by you or under your supervision?

A. Yes, they were.

Q. Are you testifying with respect to Chapter 19 of Exhibit No. (SCE-2)_____ for identification?

A. Yes, I am. Part IV, Part V, and Part VI of Chapter 19.

Q. Were those parts, that is, Parts IV, V, and VI, prepared by you or under your supervision?

A. Yes.

Q. What do those parts cover?

A. Part IV covers ratemaking considerations which include the following: A - Rate History, B - Revenue Stability, C - Marginal Cost, D - Value of Service and Competitive Considerations, E - Environmental Factors, F - Comparisons with Other Utilities, G - Cost Allocation, H - Conservation and Load Management, and I - Lifeline. Part V covers the Proposed Tariff Schedules, and Part VI covers Typical Bill Comparisons between Present and Proposed Rates.

Q. With respect to Part IV of Chapter 19, please summarize the factors which influenced you in connection with the changes that are now being proposed.

A. The determinations of the proposed changes in rate schedules were based on the requirements for additional revenues, and revenue increases were distributed to customer groups and rate schedules after giving consideration to the various factors which I listed, together with reliance on judgment and experience in applying such factors to reach a conclusion as to what is believed to be a reasonable and proper tariff schedule.

Q. Were all of the factors given equal consideration in your rate design?

A. No. In the case of certain rate designs, some of the factors may have had little or no influence, while in others, one single factor might have predominating importance.

For example, the lifeline legislation, as implemented by the Commission, is an almost totally overriding consideration in domestic rates and, except for the revenue deficiency from the lifeline sales which must be removed from other sales, of no importance in designing nondomestic rates.

One consideration in this rate design which has not previously been a significant factor, was marginal costs. To the extent practicable, marginal costs were considered in establishing the level of rates proposed for most of the rate schedules. Also of considerable concern in both our rate design and the allocation of revenues by customer group was revenue stability. During 1979, as a result of the rates authorized in Decision No. 89711, we have had a significant transfer of customers from Schedule No. A-7 to Schedule No. GS-2. Although I do not believe there is anything sacred about a particular rate schedule, I do believe it is important that the rate design either minimize transfers between rate schedules or reflect, in the over-all sales and revenue estimate, the impact of such revenue transfers.

Q. With respect to Part V of Chapter 19, please summarize briefly the significant changes proposed.

A. All of the changes proposed in the tariffs are shown in Appendix C of the application. Table 19-E, Sheet 3 of 3, indicates the estimated revenue increase proposed for each schedule, and Table 19-F, Sheets 1 to 15, summarizes the changes proposed in the level of rates.

For most schedules the only changes are in the level of rate. For Schedule Nos. A-7, GS-2, and PA-2, the existing energy blocks have been eliminated and replaced by a single energy charge. The lifeline discount for Schedule No. DMS has been increased to 15%. Schedule No. PA-1 has been changed to a monthly schedule from an annual rate. This has resulted in several changes in the Special Conditions for that schedule.

It is also proposed that Schedule No. P-1 be withdrawn. That schedule has been closed to new customers since September 10, 1969. There are presently less than 2,500 customers on the rate. It is proposed that these customers be transferred to Schedule No. GS-1 or any other applicable rate.

Decision Nos. 90146 and 90475 authorized the implementation of time-of-use rates for customers with demands in excess of 1,000 kW. By this application, the Company is proposing to extend Schedule No. TOU-8 to customers with demands in excess of 500 kW.

Other minor changes have been made in the wording of some schedules to reflect the impact of the changes proposed herein.

Q. Will you please turn to Table 19-E and indicate how the $340,183,300 total increase is broken down by schedule classifications?

A. At the estimated 1981 level of sales, the increase proposed for customers remaining on General Service Schedule No. A-7 is $28,748,800, which is an average increase of 9.6%.

For Schedule No. D. the increase is $149,932,200, which is an average increase of 13.5%.

For Schedule No. GS-1, the increase is $19,286,800, which is an average increase of 11.4%.

For Schedule No. GS-2, the increase is $69,729,400, which is an average increase of 10.1%.

For customers who are now on, or are proposed to be transferred to Schedule No. TOU-8, the increase is $43,928,900, which is an average increase of 3.5%.

For the other schedules which involve lesser amounts of money, the increase in dollars and percentages is also shown.

The total increase for all rate schedules is $340,183,300, which an average increase of 8.4% on total electric sales (9.0% on CPUC jurisdictional) for the 1981 estimated test year.

Q. Are any changes proposed for the lifeline level of usage under the Domestic Schedules?

A. Yes. Since the average system rate has increased by more than 25% over the January 1, 1976, level, I believe it is appropriate to increase rates for lifeline sales. Moreover, I believe that it will be necessary in future proceedings to propose increases in these rates. As a result, I would recommend that the Commission adopt a standard in this proceeding, setting the lifeline rate at approximately 75% of the nonlifeline domestic rate, as we have proposed in this application. However, in developing the rate design in this proceeding for domestic customers, the primary increase in lifeline rates is in the elimination of the existing lifeline tail block, so that all lifeline kilowatthours are billed at a uniform rate, which is just .097¢ per kilowatthour greater than the existing basic lifeline rate, and in an increase in the customer charge to more nearly reflect minimum meter reading and billing costs.

Q. Are there any schedules for which you propose no change?

A. Technically, certain overlay schedules are not being changed. These include

Schedule Nos. D-APS, DE, DM, UCLT, S, SCG-1, SCG-2, SCG-3, and TOU-8-1. However, customers served on these rate schedules will receive an increase in rates since the underlying rates are being changed.

No changes are proposed in the contract for fringe service with the City of Los Angeles and in the interchange and standby contracts with other electric utilities and for sales to the State of California for Department of Water Resource requirements. No change is proposed in the contract with the U.S. Department of Interior for Sequoia National Park. No changes are proposed for Catalina customers.

For certain other customers served on special onctracts, indicated in Part V of Chapter 19, no changes are proposed in those contracts, other than the level of rate as therein indicated.

Q. Are you not proposing to transfer Catalina customers to mainland system electric rates?

A. Not in this proceeding. However, in Application No. 58331, one of the proposals under consideration is to transfer Catalina electric customers to mainland system rates. That case has been submitted and was awaiting decision when this application was being prepared. We do not know whether the Commission will act favorably on that proposal prior to a decision in this case. If they were to do so, this proceeding could result in an increase in rates for those customers. However, we have not included the revenue which would be derived from those customers at proposed system rates in our calculations. Present and proposed revenues are derived assuming the existing Catalina rates.

Q. Will you please explain the material contained in Part VI of Chapter 19?

A. Table 19-G contains comparisons of Typical Electric Bills calculated at present rates, including provision for the estimated Energy Cost Adjustment, and at proposed rates. Comparisons are made for Schedule Nos. A-7, D, GS-1, GS-2, LS-1, P-1, PA-1, PA-2, and TOU-8. The levels of use for these bill comparisons are the industry standards established by the Federal Energy Regulatory Commission for such comparisons, where appropriate, and for such other levels as deemed appropriate to demonstrate the impact on customers having relatively typical sized loads. The Table, in addition to showing the amount of bills calculated on present and proposed rates, indicates the amount and percentage of the increases.

Q. Mr. Ferguson, how have you handled the Energy Cost Adjustment in designing the proposed base rates?

A. Revenues from the Energy Cost Adjustment Clause have been estimated based upon our estimate of fuel and purchased power costs during the test year. The revenues for 1981 are the same for both present rates and proposed rates, except for a minor increase as a result of the DMS change mentioned earlier. However, in order to properly establish the revenue requirement, an adjustment was made to revenues to reflect the estimated change in the balancing account as a result of either undercollections or over-collections of fuel and purchased power expense as a result of the operation of the Energy Cost Adjustment Clause.

Q. In Decision No. 90488, the Commission directed the Company to consider the transfer of the State Water Plan revenue deficiency to base rates. Is that deficiency being recovered in your proposed base rate design?

A. No, it is not. When one looks at the level of fuel and purchased power expense for 1981, I think it becomes clear that a relatively small error in estimating that expense, the level of sales, or the level of purchases can result in a substantial change in the level of dollars to be recovered as a result of those transactions. I think it is only necessary to look at the substantial increase in oil prices in 1979 to understand the potential margin of error in this expense for 1981.

Since obviously, this estimating error can be either high or low, it can work to the detriment of the ratepayer, just as much as the Company.

And, since the Commission has already concluded that the ratepayer, having received the benefits of that agreement, should also bear whatever burden may exist, we believe that burden is most equitably measured through the implementation of the ECAC.

To do otherwise can only result in either the ratepayer receiving a greater detriment than is experienced by the Company or the Company being saddled with a burden, which the Commission has already concluded should be borne by the ratepayers.

Q. Mr. Ferguson, insofar as the material contained in Appendices B, C, and F of the Application, and in Parts IV, V, and VI of Chapter 19 of Exhibit No. (SCE-2)______ is of a factual nature, do you believe it to be accurate?

A. Yes, I do.

Q. Insofar as it represents opinion, does it represent your best judgment?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

Prepared Testimony of Ronald Daniels

Exhibit No. (SCE-2)______, Chapter 20

Q. Will you please state your name and address for the record?

A. Ronald Daniels. My business address is 2244 Walnut Grove Avenue, Rosemead, California.

Q. What is your position with the Company?

A. I am Manager of Revenue Requirements.

Q. Please refer to Exhibit No. (SCE-3)______ for identification, entitled "Qualifications of Witnesses". Directing your attention to the page entitled "Qualifications of Ronald Daniels", does that portion of the exhibit accurately set forth your background, training, and experience?

A. Yes, it does.

Q. Are you testifying with respect to Chapter 20 of the Results of Operation exhibit referred to as Exhibit No. (SCE-2)______ for identification?

A. Yes, I am.

Q. Was the material in Chapter 20 prepared by you or under your supervision?

A. Yes, it was.

Q. What is the purpose of this testimony?

A. The purpose of my testimony is to summarize what has been set forth in the Results of Operations, the Financial Characteristics, and other supplemental exhibits which have accompanied our Application. It is also intended to indicate reasons for adopting certain positions and variations from past ratemaking procedures.

Q. In Part A of Chapter 20 of Exhibit (SCE-2)______ and on Chart 20-A you indicate various degrees of shortfalls of revenue occurring between 1970 and 1980. Please explain how Chart 20-A was developed.

A. The required rate of return has been assumed to be the rate of return authorized by the Commission in those years when a test year period existed. In years between test years, a straight line relationship between test years was assumed to determine a rate of return for the intermediate years.

For 1980, the required rate of return was developed by using a return on equity of 15.0% with projected embedded costs of debt and preferred stock applicable for that year. The rate of return realized on a recorded basis for CPUC jurisdictional sales is shown under the column designated "achieved". The difference between the rate of return required and achieved is multiplied by the CPUC jurisdictional rate base which is then multiplied by the net-to-gross factor resulting in the shortfall of revenue for each period. The bar graph at the right of the chart graphically presents the magnitude of the dollar shortfall from 1970 to 1980. In those periods which were not test years, the bar graph has been divided into two portions. The solid portion represents the shortfall resulting from the deficiency in rate of return when comparing the achieved with that authorized rate of return granted in the prior test year period, and the cross-hatched area represents the shortfall based on the incremental increase in rate of return so determined for the years following the test year.

Q. What conclusions do you draw from Chart 20-A?

A. It is apparent that, on a recorded basis, revenues have been deficient every year since 1970 and, therefore, have not achieved the authorized rate of return granted by the CPUC. Even in the test years, the shortfall on the average, in rate of return exceeds 0.7%. While it is recognized that the Commission is desirous of setting rates at the lowest reasonable level, it is inappropriate to establish a record in which rate of return on a recorded basis always falls below authorized rate of return. In some years, the rate of return should exceed the so-called authorized level, otherwise, even an unsophisticated investor would become doubtful of the Company's potential to earn the return authorized by the Commission. It should be recognized that the so-called authorized rate of return should fall someplace within a range considered the reasonable rate of return.

Q. With regard to Chart 20-B of Exhibit (SCE-2)______, please explain the purpose of including this chart.

A. Chart 20-B has been included as part of Chapter 20 to illustrate the relationship between the revenue effect of the increase request in our Application as compared to (1) the increase in revenue requirement associated with the addition of SONGS 2, (2) the further increase in revenue requirement which would result from the inclusion of CWIP in rate base, and (3) the revenue effect of rates based on marginal costs.

Q. What do the top two blocks demonstrate?

A. The top block shows the results of operation on existing rates for the total system. As indicated on the chart, this information has been developed in Chapters 7 through 18 of the Results of Operations Exhibit (SCE-2)______.

The next block reflects the allocation of expense to the CPUC jurisciational sales. It is further subdivided into the base rate revenues of $1.274 billion and ECAC revenues of $2.526 billion.

Q. Do the next two blocks represent the bases for the $340.2 million rate request?

A. Yes. The third block from the top of the page indicates a required increase of $302.2 million to bring the rate of return from present rates up to a level which would produce a rate of return of 10.78% on rate base.

The fourth block reflects the need for an additional $38.0 million increase in revenue which represents the additional requirement to meet attrition occurring in the period 1981-1982. The sum of these two items produces the $340.2 million rate increase request.

Q. Please explain the two blocks referring to SONGS 2.

A. It is anticipated that SONGS 2 will become commercially operational on July 1, 1981. If we were to utilize traditional ratemaking procedures and reflect the effects of adding SONGS 2 in this filing, the revenue requirements for test year 1981 would only reflect one-half year of SONGS 2 operation. The block indicating one-half year shows the $79.0 million of additional revenue which would be necessary for test year 1981 if the unit were included in the general rate case. Because of the significant addition to rate base and expenses and the impact on fuel savings, it has been determined that this unit should not be included as part of the general rate case request for rate relief but rather the costs associated therewith should be accumulated in a balancing account with base rates increased when the unit comes on line with offsetting reductions in the ECAC rate to reflect the lower fuel costs associated with the unit.

The block indicating full year operation of SONGS 2 shows that an additional $108.3 million of base rate increase above the $79.0 million previously described would be required at the time of commercial operation of SONGS 2. This means that instead of the $79.0 million going into effect on January 1, 1981, base rates would be increased by $187.3 million on July 1, 1981. Concurrently, a reduction of the ECAC of an equal amount would be implemented. Further discussion of the principles underlying this proposal will be provided in other testimony supporting the request to be made by separate application for a balancing account procedure for dealing with this plant addition.

Q. What are the purposes of the lower two blocks on this chart?

A. In recent years, much discussion has been held regarding the application of marginal costs in the development of rates to give customers appropriate pricing signals. The two blocks shown at the bottom of this chart give an indication of the rate changes necessary to reflect full marginal costs. The block representing the total inclusion of CWIP in rate base (excluding SONGS 2) provides information regarding the effect of this component of capital investment in rate base. The impact of CWIP in rate base has been presented because inclusion of such plant would be a method of reflecting marginal cost since this plant investment reflects current costs of construction as opposed to the accumulated historical costs included in the traditional development of rate base. Allowing rates to be based on the inclusion of CWIP in rate base would allow the setting of rate levels to be one step nearer to a full marginal cost signal in rate design.

Q. Do you have any recommendations regarding inclusion of construction work in progress in rate base?

A. The Company has not proposed that construction work in progress be included in rate base in the preparation of this case. I would, however, like to suggest for the Commission's consideration the potential of moving in the direction of marginal cost rates to the extent of the additional revenue requirements resulting from the inclusion of CWIP in rate base which could permit a significant degree of marginal cost pricing without any windfall to the utility, and with ultimate significant ratepayer benefits. The higher rate levels would be providing the ratepayer with a better price signal which would then allow him to decide whether he wanted additional service in the future at the higher price levels.

Three key points could be satisfied by such inclusion in rate base: (1) the rates applied could be significantly nearer to marginal costs, thus more nearly providing the price signal the economist seeks,

(2) the rate base for future years would be reduced by the elimination of AFUDC, and (3) the Company's financial position would be improved since earnings would be based on real earnings instead of a portion being supplied by AFUDC.

Q. Chart 20-C of Exhibit No. (SCE-2)______ indicates several types of attrition. Please explain what is shown on this chart.

A. As described in the text of Chapter 20, the 1979 projected results indicate that the rates as approved will not produce the return authorized by the Commission in the last general rate decision. In order that 1979 be placed on an authorized return basis, it would have been necessary to increase rates by $18.9 million as of January 1, 1979. Even if 1979 results were to reflect authorized return, approximately $226.4 million of attrition occurs between 1979 and 1981. As can be seen in the middle of the diagram, this $226.4 million is composed of increases to labor, other operation and maintenance, capital-related (rate base) costs, and financial attrition. This attrition has been offset in part by higher revenues. The financial attrition referred to here is based on the increased cost of new debt issues as well as preferred stock issues.

At this point, the return on equity is still considered to be the 13.49% authorized in Decision No. 89711. The attrition allowance requested for the year after the test year of $38.0 million in test year 1981 revenue requirements is conservative when compared to the earnings loss due to attrition of about $113.2 million per year between 1979 and 1981 absent rate relief. As indicated in the text, this $38.0 million is one-half of a full year of attrition and would be recovered in each of the two years, 1981 and 1982, under the Company's proposal to produce about $76.0 million. If we were to base a comparable figure on the attrition occurring between 1979 and 1981, we would be proposing an increase of approximately $56.6 million per year for an attrition allowance.

Q. Do you believe that with the implementation of the Energy Cost Adjustment Clause (ECAC) and the Regulatory Lag Plan, the risk faced by the Company has declined from previous periods?

A. No, I do not believe that the absolute level of risk has diminished. As a matter of fact, other factors have resulted in significantly higher risks; however, these two actions taken by the Commission have ameliorated what would have greatly increased risks of this Company in their absence. As has been shown in the test of this chapter, significant shortfall of revenue exists at the present time as well as being projected into the future. The revenues being collected through the ECAC are projected to represent approximately 66% of the total revenues collected. Had it not been for the implementation of the ECAC with its balancing account, the Company would have faced a potentially severe problem in those time periods when fuel prices were rising rapidly. Further, it is necessary for companies of Edison's size to be making decisions which require substantial funds to investigate innovative solutions to current and anticipated supply problems through installation of pilot plants. These include such projects as coal gasification, geothermal, and solar energy. While it is true that other organizations such as the Department of Energy have shared in some of these risks with Edison, there exists concern that the Company's judgment might be questioned when attempting a project which results in a relatively high cost of production. Further, under the provisions of PURPA, the Company will be required to provide new services, the resultant impacts of which are difficult to assess at this time. An example is the simultaneous buy-sell arrangements with cogeneration customers.

Q. In Paragraph 18 of Chapter 20, you referred to a contract with the Department of Water Resources under which sales of energy are made at a rate below the system average cost of energy. Do you have an opinion with regard to the inclusion of expenses relating to DWR being included in base rates?

A. Yes, it is essential that the expenses of making these sales in excess of revenues be recovered either in ECAC revenues or in base rate revenues. However, it seems to me, there is a decided advantage to recovering them in the ECAC instead of in base rates. My reason for this recommendation is that purchases and sales from DWR vary substantially from year to year which makes it difficult to estimate such transactions for 1980 and 1981 and subsequent years. If the expense associated with the sales to DWR in excess of revenues recovered were included in the ECAC, a precise accounting of the related expenses would occur since the actual sales to DWR would be utilized in calculating the expenses charged to the ratepayer through ECAC. This would also correctly recognize the fuel expense associated with such sales as opposed to being fixed on test year estimates. Further, a problem, such as the one indicated in Paragraph 18, could be handled through an ECAC adjustment.

Q. Please explain the purpose of Chart 20-D.

A. Chart 20-D has been included in Chapter 20 to provide a convenient illustration of the impact on the various customer groups. The blocks show the average price per kilowatthour (including the ECAC provision) with and without the rate increase. The dotted line labeled "ECAC" shows the amount of the price per kilowatthour which relates to ECAC. For the domestic group, two levels are shown, approximately 2.9¢/kilowatthour for lifeline sales and 4.1¢/kilowatthour for the average of the group including lifeline. Also shown on this chart is the rate increase percentage and the rate of return for each customer group.

Q. Why is the price per kilowatthour for service to the street lighting group so much higher than the other groups?

A. In the case of street lighting service, the investment in street lighting equipment requires significant revenue to cover the investment-related expenses for the street lighting installations. This is the only service where the Company provides the utilization equipment. As a result, the fuel component of the total expense is much smaller than for other customer groups.

Q. What is the purpose of Chart 20-E?

A. Chart 20-E demonstrates the impact of environmental costs on a bimonthly residential bill between 1969 and projected 1981. Also shown on the respective blocks is the amount of increase in cents per kilowatthour that has occurred for both environmental expense and for all other costs.

Q. Does the increase of environmental costs recognize expenditures which may result from current legislation regarding conversion to coal-fired generation and limitations on burning oil from foreign sources?

A. No, the costs reflected on this chart are based on the mode of operation currently in effect and does not represent the potential additional environmental costs if it is necessary to install additional facilities to meet stricter air and water quality standards. An example of such a potential requirement would be the installation of scrubbers on all of the generating plants in the Los Angeles air basin. It is estimated that the investment necessary to meet such a requirement would approach $2.0 billion. This is another example of the potential risks the Company faces.

Q. Please summarize your recommendations regarding the material in Chapter 20.

A. Based on the material presented in Edison's submittal, I recommend the following:

1. The Commission should accept Edison's estimates of expense since it has been demonstrated that even Edison's estimates

have been conservatively low in the past.

2. The Commission should provide for an attrition allowance to recognize the deficiency in earnings which occurs in the year after the test year under the Regulatory Lag Plan requirement for spacing general rate increases at a minimum of two-year intervals.

3. The Commission should grant a general rate increase effective no later than January 1, 1981, which will produce $340.2 million of additional revenue exclusive of the revenue requirement impact of SONGS 2.

4. The Commission should adopt higher expense estimates and revenue requirements in arriving at the authorized rate increase if, in fact, the wage settlements in 1979 and 1980 exceed the 7% included in the development of this case.

5. In order to allow Edison to participate in alternative energy source pilot plants, a procedure should be allowed, either through implementation of ECAC or through a separate mechanism, which would provide the Company with the cash flow necessary to support alternative energy supply projects which Edison would make between rate cases.

6. Careful consideration should be given to the coupling of any marginal cost pricing policy of the Commission to the inclusion of CWIP in rate base.

Q. Mr. Daniels, insofar as the material contained in Chapter 20 is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as the material represents opinion, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your prepared testimony?

A. Yes, it does.