Process

10

ALJ/rr/bg *

Decision 84-12-068 December 28, 1984

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY for authority to increase rates charged by it for electric service.	Application 83-12-53 (Filed December 29, 1983)
Order Instituting Investigation into the rates, charges and practices of the Southern California Edison Company.	I. 84-10-013 (Filed October 3, 1984)
And Related Matters of San Diego Gas & Electric Company Re: Nuclear O&M Expenses.	Application 83-10-12 (Filed October 6, 1983) Application 83-11-19 (Filed November 8, 1983) Application 84-12-015 (Filed December 17, 1984)

(For appearances see Appendix A.)

Table of Contents

Subject	Page
INTERIM OPINION	2
I. SUMMARY OF DECISION	2
II. INTRODUCTION	4
A. Procedural History	5
B. Public Witness Hearings	8
C. Evidentiary Hearings	11
D. OII 84-10-013	14
III. RATE OF RETURN	14
A. Overview	14
B. Capital Structure	15
C. Cost of Debt and Preferred Stock	15
D. Cost of Equity	17
1. DCF Method	18
2. Risk Premium Method	21
3. Capital Asset Pricing Model	23
4. Price/Book Test	24
5. Comparable Earnings Analyses	24
6. Risk	25
7. Discussion	30
E. Adopted Rate of Return	35a

IV. RESULTS OF OPERATIONS 37

A. Escalation 37

1. Historical Escalation 37

2. Future Escalation 38

a. Labor 38

b. Non-Labor 39

B. Sales and Revenue 40

1. Sales 40

2. Sales Forecasting Methodology 41

3. Residential Sales 42

4. Industrial Sales 43

5. Other Public Authority Sales 44

6. Annual Major Additions Rate (AMAR) Level 45

7. Revenue At Present Rates 45

C. Operating Expenses 49

1. Nuclear Related Expenses 49

a. Depreciation Expense 50

b. Rate Base 50

2. Steam Production Expense 54

a. Steam Adjustment Factor 55

b. Rents 64

c. Fuel Oil Pipeline 64

d. Redondo Beach Units 1-4 64

e. Coal Inventory Write-offs 65

f. Fuel Storage Tank Lease 65

g. Property Damage Expense 66

h. Research, Development and Demonstration Expense 66

3. Hydraulic Production Expense 66
a. Estimating Methodology 67
b. Adjustments 68
(1) Shaver Dam Repairs 68
(2) Hydro Production Rents 69
(3) Property Damage Expenses 69
(4) Research, Development And Demonstration Expense 70
4. Other Production Expense 70
a. Estimating Methodology 71
b. Adjustments 72
(1) Property Damage Expense 72
(2) Research, Development And Demonstration Expense 73
5. Transmission Expense 74
a. Estimating Methodology 74
(1) Account 562, Station Expenses .. 75
(2) Account 570, Maintenance of Station Equipment 76
(3) Account 571, Maintenance of Overhead Lines 77
b. Adjustments 78
(1) Big Creek Transmission Line 78
(2) Wheeling Charges 78
(3) Research, Development, and Demonstration 78

6. Distribution Expense 78
a. Estimating Methodology 79
b. Adjustments 84
(1) Deteriorated Pole Replacement Program 84
(2) Underground Vault Inspection ... 87
(3) Maintenance of Underground Lines 87
(4) CVR Regulator Program 88
(5) RAC/RAM Switches 88
(6) Landscape Care 88
(7) Research, Development and Demonstration Expense 89
7. Customer Accounts Expense 90
a. Estimating Methodology 91
(1) Account 902, Meter Reading Expense 91
(2) Account 905, Miscellaneous Customer Accounts Expenses .. 91
b. Adjustments 92
(1) Customer Service Representatives 92
(2) Customer Accounting System 92
(3) Postage 92
(4) Account 904, Uncollectible Accounts 93
c. Additional Customer Accounts Issues 93
(1) Joint Meter Reading, Billing and Collection 93
(2) Inter-Utility Credit Follow-Up System 95

8. Customer Service And Informational Expense 96

9. Administrative and General Expense 97

a. EEI Dues 98

b. Estimating Methodology 99

c. Summary and Discussion 107

d. Adjustments 111

(1) Westinghouse Litigation Costs .. 111

(2) San Onofre Unit 1 Personnel 111

(3) San Onofre Unit 1 A&G Expense Charged To Others 111

(4) Franchise Fees 112

(5) Pensions and Benefits - Aaccount 926 112

(6) Research, Development And Demonstration Expense 112

e. Lucerne Valley Licensing Costs 113

10. Depreciation Expense 116

11. Tax Expense 116

a. Income Taxes 116

b. Ad Valorem Taxes 117

c. Other Taxes 117

D. Rate Base 118

1. Plant Forecast 118

a. Fixed Capital 118

(1) Big Creek To Magunden Transmission Line 118

(2) Devers To Serrano Transmission Line 121

2. Property Held For Future Use 123

3. Working Cash 123

4. Load Management Programs 127

E. Jurisdictional Allocation 128
F. Net-To-Gross Multiplier 128
G. Summary of Earnings 128
V. COMPETITIVE BIDDING 129
VI. FEMALE/MINORITY BUSINESS ENTERPRISES 130
A. Overview 130
B. Staff's Additional Requirements 131
1. The Establishment of Goals 132
2. Data Requirements 133
3. Additional Funding Required 133
C. Positions of the Parties 134
1. Edison's Position 134
2. Staff's Position 134
3. Position of U.S. Black Chamber of Commerce, et al 136
D. Discussion 137
VII. RESEARCH, DEVELOPMENT AND DEMONSTRATION EXPENSE (RD&D) 140
A. Policy Issues 140
1. Overview 140
2. Guidelines 142
3. Cost-Benefit Evaluation 143
4. Project Ranking Criteria 143
5. Reporting Format 144
6. Third Party Use 145
7. Trend In Funding Levels 146
8. EPRI Expenses 149
9. Issues Related To Edison's 1982 Test-Year General Rate Case Decision 151

B. Test-Year Expenditure Levels 152
1. Acid Rain/Fog Research 152
2. Activities To Be Co-sponsored Or Done By Others 155
3. Activities Which Belong In Other Programs 157
4. Activity Which Should Not Be Performed At Ratepayer Cost 159
5. Expenses Which Should Be In A Different Proceeding 159
6. Other Adjustments 160
C. Discussion 161
D. Time-of-Use (TOU) Metering Research 162
E. Three Year Rate Case Cycle 164
VIII. CONSERVATION AND LOAD MANAGEMENT 166
A. General Policy 166
1. Stay-The-Course Funding 174
2. Program Cost-Effectiveness 180
B. Commercial/Industrial/Agricultural Conservation 183
1. Incentives 185
2. Equal Percentage Energy Savings 187
3. Premium Labor Rate 189
4. Conclusion 191
C. Residential Conservation 192
D. Load Management Programs 196
E. Order of CEC 198

F. Other Programs 201
1. Advertising 201
2. Measurement 202
a. Energy Services Reporting System 203
b. SIC Coding 203
c. Remaining Measurement Issues 204
3. Management/Administration Regulatory Support 204
G. Other Conservation/ Load Management Issues 205
1. Management Flexibility 205
2. Three-Year Rate Case Cycle 208
IX. RESOURCE PLANNING 212
A. Overview 212
B. Reserve Margin Requirement 213
C. Contingent Retirements 215
D. Data Requirements 216
E. Studies to be Undertaken 217
F. Conclusion 218a
X. COGENERATION AND SMALL POWER PRODUCTION 219
A. Progress and Goals 219
B. Other Issues 222

XI. MARGINAL COSTS 225

A. Introduction 225
B. Economic Time-Frame 228
C. Adoption of A Uniform Methodology 230
D. Marginal Cost Components 231
1. Marginal Energy Costs 231
a. Edison's Position 231
b. Staff's Position 237
c. Interested Parties' Positions 241
(1) Computer Model Approach 241
(2) Edison's Alternative Approach (Exhibit 9(A)) 247
d. Discussion 252
2. Marginal Cost of Demand: Generation, Transmission and Distribution 257
3. Marginal Customer Costs and Facilities Charges 263
4. Marginal Costs by Customer Group 264a

XII. REVENUE ALLOCATION 266

A. Revenue Allocation Methodology 266
1. Proposed Methodologies 266
2. Discussion 269
B. Requests for Exclusion from Adopted Revenue Allocation Methodology 272
1. California City/County Street Light Association 272
2. Schools Committee to Reduce Utility Bills (SCRUB) 275
C. Adopted Revenue Allocation 276
D. Intervening Offset Proceedings 278
E. Present Rate Revenues 282

XIII. RATE DESIGN 284

A. Residential Rate Design 286
1. Baseline Allowances 286
a. Commencement of Baseline 288
b. Climate Zone 15 292
c. Baseline for Residential Hotels 296
d. Prorationing 299
2. Residential Rate Design 301
3. Residential Time-of-Use Rates (Schedule TOU-D) 303
4. Submeter Discounts 304
B. Daily Rates 310
C. Commercial and Industrial Rate Design 311
1. Non-Time-of-Use Rates 311
a. GS-1 and GS-2 Schedules 311
b. PA-1 and PA-2 Schedules 313
2. Time-of-Use Rates 315
a. Time-of-Use Issues 316
(1) Edison and Staff Proposed Rate Design 316
(2) TOU-8 Demand Charge 319
(3) TOU-8 Interruptible Rates and Voltage Discounts 321
(4) Exemptions from TOU-8 Rates 327
(5) TOU-PA (Agricultural) and TOU-GS (LSMP) Rate Schedules and Rate Design 328
b. Discussion 329
3. Costing Periods for Time-of-Use Rate Schedules 334
4. Streetlighting 338
5. SCRUB 343

XIV. FINDINGS AND CONCLUSIONS 346

A. Findings of Fact 346
B. Conclusions of Law 366

INTERIM ORDER 366

APPENDIXES

A Appearances
B Results of Operations
C Baseline Quantities
D Rate Schedules
D-1 Rate Schedules
D-2 Rate Schedules

GLOSSARY

INTERIM OPINION

I. SUMMARY OF DECISION

This decision reduces Southern California Edison Company's base rates by $115.8 million or 4.49% for 1985. Base rates cover all costs of doing business except fuel costs.

Edison originally requested an increase in base rates of $453.0 million or 17.57% for 1985. Following hearings which lasted through most of 1984, Edison agreed that as a result of increased sales, transfer of some issues to other proceedings and stipulations to Commission staff estimates for certain expenses, their original request finally amounted to a rate reduction of $15 million.

In comparison, the Commission staff's final position was that rates should be reduced by $186 million.

The Commission's decision in this proceeding will be combined with increases resulting from the following two offset proceedings which the Commission is considering at this time: 1. A.82-02-40 concerning the Major Additions Adjustment Clause for San Onofre Nuclear Generating Station Unit No. 2, and 2. A.84-02-11 concerning the Electric Cost Adjustment Clause procedure. The net effect of the decrease in this proceeding and increases resulting from other proceedings will be reflected in the new electric rates adopted for 1985.

The net effect of all proceedings considered at this time is a revenue increase of $184.2 million. The effect on a typical residential customer's electric bill for 500 kWh is an increase of $1.69/month, according to staff.

Several features of this decision deserve mention. First, Edison's request to increase the return on equity (return on its investment) from the last authorized rate of 16% to 16.75% was denied. Instead the Commission held Edison's return on equity at 16%.

Second, the decision adopts a policy of "holding the line" on expenditure for conservation and load management programs to the same levels authorized for 1984. The decision authorizes $55.2 million

annually for conservation and load management program expenses. While some factors indicate that a less aggressive approach to conservation is appropriate, the Commission declined to dismantle existing programs recognizing that the energy scene may change quickly and dramatically.

Third, the decision provides an expenditure level of $45.1 million for research and development projects. The objective of these programs is to provide short-term and long-term options related to new technologies for clean and efficient generation with minimal environmental social impacts.

Fourth, the decision provides Edison with a 10.4% increase for operation and maintenance expenses. These expenses cover costs of maintaining Edison's generation, transmission and distribution plant.

Fifth, on an overall basis, the decision grants Edison a 17% increase for all expenses including conservation, research and administration but excluding franchise fees, taxes, and return on investment.

The revenue allocation and rate design adopted in this proceeding will have the following impact on Edison's residential customers: the effective rate change for the domestic customer class as a whole will be an increase of 0.14%. To avoid the negative impact of implementing the transition from lifeline allowances to baseline quantities in a single step, the Commission has adopted a phased-in implementation of baseline. Additionally, the Commission has adopted a cap (200 kWh) on the maximum kWh reduction that a customer could experience in their lifeline allowance at any one time due to the transition to baseline.

II. INTRODUCTION

This proceeding was originally assigned to President Leonard M. Grimes, Jr. and on his retirement reassigned to his successor President Donald Vial. Administrative Law Judge (ALJ) Sara Myers conducted the hearings on marginal cost, revenue allocation, and rate design segments. ALJ Bertram Patrick was responsible for the remainder.

Edison filed this application on December 29, 1983, which requested additional revenues of $453.0 million for test year 1985 and an additional $110.3 million for attrition year 1986.

By letter dated March 14, 1984, Edison announced that certain components of its request were being reduced, and that certain other components were proposed to be transferred to other proceedings. The reductions totalled approximately $63 million, which included lowering the requested rate of return on common equity from 17.5 percent to 16.75 percent and downward adjustments in Edison's expense estimates for conservation/load management, depreciation, and taxes. The proposed transfers totalled approximately $70 million, which included deferral of the determination of additional revenue requirement for nuclear decommissioning to OII 86, and transfer of the investment-related cost component associated with San Onofre Units 2 and 3 to the MAAC proceeding. Together, the reductions and proposed transfers lowered Edison's request from $453 million to approximately $320 million.

On May 22, 1984, Edison announced that, upon continued analysis of staff's Results of Operations Report and from use of a more current sales forecast, agreement had been reached regarding certain adjustments recommended by staff. The net effect of these agreements resulted in a further $93 million reduction, bringing Edison's request for test year 1985 to approximately $227 million.

On September 24, 1984, during updating hearings, Edison agreed that, as a result of revised sales estimates and other stipulations to certain expense levels, since the revised sales estimates would generate increased revenue, rather than a rate increase a $15 million revenue reduction was appropriate.

On the other hand, staff contend that, based on the increased sales estimate, a reduction of $186 million is warranted.

The details of the company and staff positions and the Commission's disposition of the various issues, is set forth in this opinion.

A. Procedural History

On October 26, 1983, the Commission accepted Edison's Notice of Intention 110 (NOI 110) to file a general rate increase application for authority to increase base rates for electric service.

Edison filed this application on December 29, 1983.

A Prehearing Conference was held on February 2, 1984, at which a tentative hearing schedule was distributed and it was announced that in addition to the regular evidentiary hearings the Commission would conduct three en banc hearings at intermediate stages during the evidentiary phase of the case. The first en banc hearing took place in Los Angeles on April 11, 1984, during which the parties made oral presentations identifying major issues for the Commission's consideration. The second and third en banc hearings took place in San Francisco on May 22 and July 12, 1984, respectively, during which the parties presented their positions on the issues addressed in the evidentiary hearings. During all three en banc hearings, the parties responded to questions posed by the individual Commissioners on both policy and factual matters.

On February 2, 1984, staff moved that the costs associated with ownership of San Onofre Units 2 and 3 be excluded from consideration in this case. Edison filed its response to staff's motion on Feburary 14, 1984, agreeing with staff's motion to exclude, provided the costs in question be included in Edison's base rates at the earliest practicable date after the Phase 2 reasonableness review in the MAAC proceedings has been completed. On February 27, 1984, the ALJ granted staff's motion, ordering Edison to prepare a separate exhibit containing the tables in each chapter of Edison's Results of Operations Report, adjusted to reflect removal of all nuclear-related plant and expense.

On February 7, 1984, the ALJ ruled that certain incremental heat rate (IHR) data, required to be considered in ECAC proceedings pursuant to Decision (D.) 83-10-093, may be considered in these general rate proceedings as originally filed. The ruling specified that future IHR data filings required pursuant to D.83-10-093 were to be considered in ECAC proceedings, commencing with Edison's 1985 ECAC/Reasonableness Review filing. It should be noted, however, that since the issuance of the ALJ's ruling, the Commission has issued D.84-03-092. By that order the Commission has returned consideration of incremental heat rates, currently referred to as incremental energy rates (IERS), to the general rate case. Thus, future IHR data related to existing operational resources should not be presented by Edison in its ECAC proceedings, but rather in its future general rate case applications.

On March 16, 1984, Edison moved for an exception to the Rate Case Plan, to permit Edison to update its exhibits with respect to Operation and Maintenance (O&M) expenses for San Onofre Units 2 and 3, in compliance with D.84-02-090. Staff supported Edison's request for an exception to the Rate Case Plan on the condition that

Edison's request not result in an increase in revenue requirement and that Edison not be permitted to introduce new material relative to refueling expense, beyond that already filed with Edison's application. On April 18, 1984, the Commission issued D.84-04-051, ordering that the issue of 1985 O&M expenses for San Onofre Units 2 and 3 should be fully explored in this proceeding and that Edison may introduce new material on refueling expense. The revised showing, however, should not produce a new total revenue requirement which would exceed that originally requested and noticed to Edison's customers. Edison submitted its supplemental testimony on the subject of O&M expenses for San Onofre Units 2 and 3 on June 20, 1984. All nuclear-related aspects of this case were deferred to a separate phase of hearings, scheduled for the week of September 17, 1984.

Pursuant to a stipulation executed and filed with the Commission on September 17, 1984, Staff, Edison, and San Diego Gas and Electric Company (SDG&E) agreed to recommend that the Commission adopt the operation and maintenance and administrative and general expense estimates for San Onofre Units 1, 2, and 3 for 1985, 1986, and 1987 as set forth in the stipulation, in lieu of litigating the issues related to those estimates in this proceeding.

The subjects of Female Minority Business Programs, attrition, jurisdictional allocation and updating permitted under the Rate Case Plan, were deferred to hearings scheduled for the week of September 24, 1984. Following the conclusion of these hearings the matter was submitted subject to receipt of certain late-filed exhibits, final briefs due on October 18, 1984 and oral argument before the Commission en banc on November 13, 1984.

B. Public Witness Hearings

Public witness hearings were held in afternoon and evening sessions in Long Beach, Redlands, Palm Desert, Visalia, and Oxnard on March 16, April 17 and 18, and May 14 and 15, 1984 respectively. These sessions were scheduled especially for the purpose of receiving testimony and statements directly from members of the public.

A total of 31 members of the public presented statements, nearly all protested the magnitude of the proposed increase. It was pointed out that people on low or fixed incomes had no ability to absorb the proposed increase and it would mean that these people would have to pay any increase from the little money they had for food. The Commission was asked to look for a way to "fix the rates" for low-income, fixed income, and senior citizens since lifeline rates should be targeted for the people that really need it. Despite the opposition to the increase, there were no complaints regarding Edison's service.

The various school districts in Edison's service area strongly opposed any increase. For example, L.A. Unified School District (LA) pointed out that inspite of an agressive energy conservation program, utility expenses excluding telephone increased from $12.7 million in 1976-77 to $26.5 million in 1982-83, an increase of 110 percent whereas the increase in their budget was only 38 percent. LA emphasized that approval of any rate increase takes dollars away from the educational programs on a dollar-for-dollar basis. However, LA did mention that in some years the cost avoidance through implementing and fine tuning energy conservation measures almost offset the rate increases. Although they were opposed to the increase, all the school districts were appreciative of the assistance provided by Edison in the conservation and load management area and supported continuation and expansion of the incentive programs and time-of-use meters.

The Coachella Valley Association of Governments (CVGA) noted that as a result of its involvement in Edison's prior rate cases, the Commission had increased the lifeline allowance for desert residents and ordered Edison to conduct a "study to determine the effects of seasonal customer residency on average residential usage within its system." They now had two points which they wished this Commission to consider. First, according to CVAG, the new baseline allowances to kilowatt-hours (kWh) cannot be properly determined until the study is completed on seasonal residency. CVAG contends that, if many of the residential units in the area have no people in them during the six hottest months, then these units should not be included in calculating what the baseline allowances should be for residents who have to live there year-round.

CVAG argued that the year-round residents are generally the lower income people who can least afford their monthly electrical bills. According to CVAG, they have to stay put to keep their jobs, or their retirement income is too modest to support another residence in a cooler climate.

The second point raised by CVAG is that it does not appear to be fair to the Coachella Valley residents for Edison to recognize a climate zone larger than the Coachella Valley such as the Lower Desert area which would include also Imperial Valley areas, for the purposes of determining baseline allowances. According to CVAG the Coachella Valley is a distinct climate zone that requires more therms of energy for air conditioning than any other area in the State of California. CVAG submits that tying it to other areas that require less therms for air conditioning will lower their baseline. According to CVAG they need a varying baseline that accurately reflects the greater demand during the hotter months and less demands during the cooler months. CVAG, while noting that both the staff and Edison are proposing such a baseline, believes it needs finer tuning to actual demand than has so far been proposed.

Members of the dairy industry pointed out that their plants run at 100% capacity and do not have the ability shift much load because milk should be processed when received by the plant. They stated that the industry has invested heavily and put a lot of effort into conservation and cogeneration plant but has difficulty staying even since the cost of dairy products has increased only 7 to 8 percent per year while their energy costs have increased 25 percent per year. They commended Edison for its work with the dairy industry.

Several farmers testified that it was impossible for them to take advantage of time-of-use rates since they take water from irrigation canals continuously on a 24-hour basis. They stress that since the marketplace determines the price of their product and because of lack of any margin due to outside competition, the farmers cannot absorb further increases for energy cost. However, the farmers appreciated the service provided by Edison.

In summary, the testimony provided at the public witness hearings is a good indication that while there is strong opposition to any rate increase, the general consenses is that Edison is providing good service, is vigorously pursuing conservation and load management programs and is working with all segments of its ratepayers.

C. Evidentiary Hearings

Hearings on the technical aspects of Edison's request began on March 26, 1984. Fifty three days of technical hearings were conducted through September 28, 1984.

Formal prepared testimony was received in the following areas:

Policy: Edison submitted testimony on management's strategy to manage human and capital resources effectively, the financial requirements of Edison, the research, development and demonstration goals being pursued, and the objectives of the conservation and load management programs, and cogeneration and small power production programs proposed by Edison. Testimony was also presented by Edison and staff on the company's Competitive Bidding Procedures and its Female/Minority Business Enterprise Program.

Financial Considerations: Edison provided forecasts of Edison's financial condition including the cost of capital and required rate of return for the 1985 test year and 1986 attrition year. Staff also presented evidence on financial considerations, as did the California Association of Utility Shareholders (Shareholders), and the Federal Executive Agencies/Department of the Navy (FEA).

Cost of Producing Electricity: Edison provided information on its operation and maintenance expense, administrative and general expense, tax expense, and depreciation expense for test year 1985 and attrition year 1986. Staff reported on Edison's results of operations and recommended certain changes in the treatment or allowance of expenses for the test and attrition years.

Research, Development & Demonstration: Edison provided information on its expenses for research, development and demonstration activities for test year 1985 and attrition year 1986. Staff reported on Edison's proposed activities in this area, and recommended certain minor adjustments in program prioritization and funding levels.

Conservation/Load Management: In addition to the policy evidence on conservation and load management noted above, Edison provided detailed descriptions of the programs it proposes to implement to achieve its goals in these areas. Staff reported on Edison's proposed programs and recommended certain changes to the programs and expense allowances proposed by Edison.

Rate Design and Cost of Service: Edison proposed a rate design to spread the increased cost of service to the various customer groups and rate schedules. Edison also provided calculations of its marginal and avoided costs and proposed an alternative methodology for calculating capacity payments to qualifying facilities (QFs). Staff reported on its own rate design proposals and suggested an alternative method of calculating capacity payments to QF's.

Several interested parties presented evidence with respect to rate design and marginal/avoided cost issues, including: Independent Energy Producers (IEP), Western Mobilehome Association (WMA), California Manufacturer's Association (CMA), Ultrasystems, Inc. (UI), California Large Energy Consumers Association (CLECA), Henwood Associates, Inc. (HAI), Federal Executive

Agencies/Department of the Navy (FEA), Association of California Water Agencies (ACWA), Schools Committee for Reducing Utility Bills (SCRUB), California City-County Street Light Association (CALSLA), and State Energy Assessment Program (SEP).

Concurrent opening briefs were filed in two parts: the first part, addressing cost of capital, on July 31, 1984, and the second part, addressing non-nuclear results of operations, on August 17, 1984. The concurrent reply briefs were filed on September 14, 1984. Final briefs covering the updating phase were filed on October 18, 1984.

Briefs were received from: California Association of Utility Shareholders (Shareholders), Occidental Geothermal, Inc. and Ultrasystems Incorporated (UI), Independent Energy Producers Assn. (IEP), Schools Committee for Reducing Utility Bills (SCRUB), General Motors Corporation and Union Carbide Corporation (GM/Union Carbide), California Farm Bureau Federation (Farm Bureau), Association of California Water Agencies (ACWA), California Manufacturers Association (CMA), Federal Executive Agencies (FEA), California Energy Commission, Federal Paper Board Company, Inc., Department of General Services of the State of California (State), California Large Energy Consumers Association (CLECA), California City-County Street Light Association (CAL-SLA), Western Mobilehome Association (WMA), Public Advocates, Inc.

D. Order Instituting Investigation (OII) 84-10-013

On October 3, 1984, the Commission issued OII 84-10-013 in order to provide a procedural vehicle for consideration of any recommended decrease in Edison's base rate revenues for 1985. In order to provide an evidentiary basis for a decision to be rendered in the OII, the Commission incorporated the rate case record into the OII.

Edison notified the ALJ that it will not be offering further evidence to supplement the record.

Accordingly, the OII should be considered as nothing more than a procedural vehicle for reducing Edison's rates pursuant to the ultimate disposition of this general rate case proceeding.

III. RATE OF RETURN

A. Overview

Testimony on cost of capital was presented by John B. Adams for Edison, Linda Gori for staff, Dr. John B. Legler for FEA and Philip C. Presber for Shareholders. The following table summarizes their recommendations:

Summary of Recommendations on Return on Common Equity and Return on Rate Base (Percent)

	Return on Common Equity	Return on Rate Base 1985	Return on Rate Base 1986
Edison	16.75%	13.05%	13.04%
Staff	15.25-15.75	12.30-12.53	12.22-12.45
FEA	14.6-15.8	12.01-12.55	11.93-12.47
Shareholders	17.0-17.50	-	-

There is a minor issue related to capital structure and cost of new debt which we will address before we discuss the main issue which is cost of equity.

B. Capital Structure

Edison assumed the capital structure shown in the following table in order to estimate its financial requirements:

Capital Structure
Average Year 1985 & 1986

Debt	45.0%
Preferred Stock	10.0
Common Equity	45.0
Total	100.0%

Staff and FEA accepted Edison's target capital structure as reasonable.

Recognizing that the capital structure is only an estimate for a projected period of time and that capital structures do change as a result of external financings and retained earnings, we find the capital structure proposed by Edison to be reasonable and appropriate for this proceeding.

C. Cost of Debt and Preferred Stock

Edison, staff, and FEA submitted evidence on the imbedded cost of debt and preferred stock. The following table summarizes the recommendations:

Parties' Recommended Imbedded Costs of
Debt and Preferred Stock

	Imbedded Cost Debt		Imbedded Cost Preferred	
	1985	1986	1985	1986
Edison*	10.42%	10.40%	8.24%	8.24%
Staff	10.27	10.09	8.17	8.17
FEA	10.27	10.09	8.17	8.17

*Revised estimate.

During the updating hearings Edison revised its imbedded cost of debt. The cost of debt was revised to reflect an estimated 14% average rate for 1985 and 13% for 1986 new issuances of double-A rated utility bonds. Edison does not plan to issue more preferred stock in 1985 and 1986.

Regarding preferred stock, since there are no proposed offerings for 1985 and 1986, we will adopt the cost rate of 8.17% proposed by staff. This rate will be reflected in the adopted rate of return calculation set forth at the end of this section.

Although FEA's witness accepted the staff's projected cost of new debt, he warned that the 12% AA bond rate assumed by staff for new issuances might be too low. He recommended that the Commission re-evaluate interest rate projections later in the year.

Staff argues that it is true that at first blush it appears that a 12% AA utility bond rate may understate interest rates for the test period; however, Edison's total financing package for the test period includes very low interest pollution control bonds (Exhibit 50, Table No. 5) and access to the Eurobond market which produces measurable savings over debt issues in the domestic market. Accordingly, staff contends that the 12% forecast is not unreasonable.

Edison and Shareholders argued that the company assumed refinancing of $950 million of high-coupon debt during the 1984 through 1986 time period. Edison and Shareholders submit that since interest rates have not declined as expected, much of this refinancing may not be cost effective. Therefore, they believe Edison's imbedded cost of debt in 1985 and 1986 will remain high. Accordingly, Edison and Shareholders request that the Commission consider the most recent data on the cost of debt and preferred stock at the time it renders its decision in this proceeding.

Also, during the updating hearings, Edison noted (in Exhibit 155) that because of the anticipated higher interest rates Edison assumed "$150 million of the refundings shown in 1985 will not be cost-effective in 1985 or 1986. Moreover, the remaining $300 million of refundings shown in 1985 will not be cost-effective until 1986. These changes have been reflected in (Edison's) updated estimates of imbedded costs."

We will reflect, in our cost of debt calculation, only those refundings that are cost-effective based on the adopted rate for new debt.

On the subject of pollution control bonds, Edison noted that it is the company's practice to use tax-exempt financing to the maximum extent possible for pollution control facilities in order to minimize the cost to its customers. In Edison's initial filing (Exhibit 2) it was assumed that $196 million of tax-exempt financing for San Onofre would be issued and drawn down in 1984. For reasons set forth in late-filed Exhibit 156, Edison concludes that for 1984 instead of $196 million as originally expected, Edison will issue $162 million of these tax exempt bonds. We will reflect this change in our calculation of Edison's cost of long-term debt.

The adopted cost of new debt is addressed in the discussion section of this chapter.

D. Cost of Equity

First, we will evaluate the quantitative analysis presented in this proceeding, and then evaluate the qualitative discussion of risk presented by the parties, in order to decide where within the range Edison's market rate of return lies. Our final determination will reflect our best judgment concerning the relative weight of all the factors presented in this case.

1. DCF Method

The following table summarizes the estimates provided by the parties:

Party	DCF Estimate: Expected Dividend Yield	Expected Growth Rate	Total DCF Estimate
	%	%	%
Edison	10.0	6.0-8.0	16.0-18.0
Staff	9.45-9.50	5.75-6.25	15.20-15.75
FEA	10.5	5.0-5.5	15.5-16.0
Shareholders			

As applied by the witnesses in this proceeding, the DCF model is based on the premise that the cost of common equity is equal to the expected dividend yield plus the expected growth in dividends. The witnesses agree with this general definition; however, they disagree as to how the expected dividend yield and growth assumptions should be determined.

In its simplest form the model assumes that a company has a constant payout ratio and its earnings are expected to grow at a constant rate. Thus, if a stock has a market value of $50 a share and an expected annual dividend in the coming year of $5 a share, and its earnings were expected to grow at 5% per year, then the cost of equity for the company is the 10% dividend yield plus the growth rate of 5% or a total of 15%. This is the version of the model utilized by the witnesses.

Turning to the mechanics of the DCF method, there are two components which must be determined: the expected dividend yield and the expected dividend growth rate.

We will first discuss the growth rate which is the most difficult aspect of implementing this theory. There are essentially three methods generaly used to estimate growth rate: (1) analysis of historical growth rates, (2) projections of analysts, and (3) the calculation of a sustainable growth rate by use of the formula where the growth rate is calculated by multiplying the expected retention rate times the expected return on book equity.

As the basis of its estimate of growth rate, staff relied upon the composite average historical 5 and 10-year recorded growth rates in earnings and dividends of 24 "comparable" or equivalent risk utilities plus Edison. Staff also used the projections of dividend growth published by Value Line Investment Survey (Value Line).

Both FEA and Edison declined to use the historical approach to estimate growth rate because they consider Edison's past trend in growth volatile.

Staff argues that its use of a composite average of 24 comparable companies plus Edison mitigates the error in using recorded data related only to the one company under review. Staff chose the 24 utilities based on three different risk criteria: bond ratings, common stock betas, and equity ratios and found the sample to be "comparable" in risk to Edison. Consequently, staff believes investors would expect similar returns. Further, staff argues that Edison's dividend yield (one component in the DCF return) was found to be similar to the average of the group so that an expected growth rate derived from the composite would result in a reasonable growth rate for Edison.

However, Edison argues, at great length, that the "comparable" utilities used by staff are not comparable with Edison in terms of risk. According to Edison, because of changes in the environment of electric utilities, historical growth rates are not reasonable proxies of current expectations.

In preparing its estimate of growth rate, FEA considered the three methods mentioned above, but its primary reliance was on the "retention growth rate" approach.

This method assumes that the estimate of future growth is the percentage of earnings retained (retention rate) multiplied by the return on equity. For example, if a company earns 10% on equity, but pays all the earnings out in dividends, the "plowback" factor will be zero and earnings per share will not grow. Conversely, if the company retains all its earnings and pays no dividends, it would grow at an annual rate of 10%. FEA agrees that this simplistic approach requires certain basic assumptions, but FEA believes that reasonably stable average rates will produce an acceptable estimate of long-term growth rates.

Based on forecasts by Value Line and Merrill Lynch, Pierce Fenner & Smith Inc. (Merrill Lynch), FEA adopted a retention rate of 35% and future return on equity of 15.5% - 16% to derive an adopted growth rate of 5.0% - 5.5%.

Edison argues that FEA has misused the data from Value Line and Merrill Lynch. Edison points out that the direct estimates of dividend growth were 7.0% by Value Line and 5.0% by Merrill Lynch. Rather than relying on these direct estimates of dividend growth, FEA used the data provided to develop their own "retention growth rate" which worked out to be 5.4% from Value Line data and 5.6% from the Merrill Lynch data. In view of these growth rates calculated by FEA, Edison questions the appropriateness of FEA's adopted range of 5.0%-5.5%.

Edison further argues that estimates by independent financial analysts demonstrate that the dividend growth rates estimated by staff and FEA are unreasonably low. Edison refers to projections published by eight financial analysts which it used, (Exhibit 3, Table 12). Edison notes that these projections had the following distribution:

Number of Financial Analysts	Range of Expected Dividend Growth Rates (Percent)
1	5.0 to 5.9
2	5.0 to 6.9
3	7.0 to 7.9
4	8.0 to 8.9

The projections of these independent financial analysts averaged 7.0%. Based on these projections Edison concludes that investors expect dividend growth of between 6 and 8 percent.

On the other hand, FEA contends that growth rates published by investment houses are too high to be used in the context of the DCF model which requires a long-term sustainable growth rate. FEA notes that based on a growth rate of 8% and retention rate of 37.5% adopted by Edison, the required sustainable return on book equity is 21.3%. FEA does not believe that this is a reasonable expectation on the part of investors. FEA observes that for a lower return on book equity to produce this growth rate (on a sustainable basis), Edison would have to sell equity at well above book value which FEA submits, investors will not expect to occur.

2. Risk Premium Method

The basic assumption for this method is that corporate equity securities would have a higher return than its debt. The theory usually is implemented by adding a "risk premium" to the yield on a company's long-term debt or utility bonds of the same rating. The problem is the calculation of the risk premium. There is disagreement between the parties as to the time period to use and how the risk premium should be determined.

Under FEA's approach, the expected risk premium is the difference between a DCF calculated return on equity and the then current bond yield. For the DCF calculation, FEA developed an expected growth rate based on 10 years of projected data for earnings per share, dividends per share and return on equity from Value Line's reports towards the end of each year on Edison. On this basis FEA's calculated expected risk premium averaged about 5.3% relative to the December 20-year Treasury bond rate and 4.1% relative to Moody's Aa utility bond rate of the preceeding year for the period from 1973 to 1984. Also, FEA determined that the risk premium for the last five years (1980-1984) averaged 3.9% relative to the Treasury rate and 2.3% relative to the Aa rate. Then, FEA added the average risk premium for the last five years to the current yield as of March 30, 1984, (Treasury Bond rate 12.34% and Aa utility rate 13.73%) to derive an estimated required return of about 16.0%-16.2%.

However, FEA expressed reservations about the risk premium method and cautioned the Commission, for many reasons, to not rely on this approach especially if it is not supported by the estimates produced by other methods.

Edison points out that the capital market during the 1979 to 1982 period was characterized by extreme volatility and uncertainty. Therefore, in Edison's opinion it would be inappropriate to use the 1979 to 1982 period by itself to estimate the risk premium for 1985 through 1987. Accordingly, Edison contends that to mitigate market perturbations such as those existing during the 1979 to 1982 period, the risk premium must be determined over a long period of time. Edison used thirty years for earned returns and seven years in its prospective DCF approach. Edison notes that had consistent data been available, it would have used a longer period for both analyses. According to Edison, its analyses indicates the risk premium should be between 698 and 726 basis points.

For purposes of comparison, if Edison's risk premium is added to the current yield for debt instruments as used by FEA the resulting estimated required return is about 19.5%-20.8%. FEA argues that such expected returns resulting from the risk premium calculated by Edison are unrealistic.

Shareholders provided a historical risk premium analysis based on the cost of equity being equal to Edison's earnings to price ratio. Their approach to developing a risk premium, was to generate a ratio of recorded annual earnings per share to an average price derived by taking two points (the annual high and low market price) in time and comparing this ratio to Aa utility bond yields. The resulting "risk premium," varies from 9.77% to 0.97% in the 10 years of data analyzed. Because of the volatility of the 10-year period analyzed, Shareholders developed an average risk premium for ten years, two separate five-year periods, and three years. Then Shareholders averaged the two five-year periods and the three-year period to derive an adopted risk premium of 4%, which added to a projected interest cost for Moody's Aa Utility Bonds resulted in a recommended return on common equity of 17.0%-17.5%.

FEA and staff argue that Shareholders analysis is nothing more than a earnings/price ratio for each year on recorded earnings and it is deficient on its own merits.

3. Capital Asset Pricing Model (CAPM)

FEA provided a CAPM analysis in response to encouragement given in the last PG&E general rate case decision (D.83-12-068 p. 28c). However, FEA had reservations regarding its use in this proceeding, other than as a check on the reasonableness of estimates produced by other methods.

The CAPM model estimates the return on common equity by adding a risk premium to the yield on risk free securities. It is similar to the risk premium analysis discussed previously but CAPM determines the risk premium in a two-step process which requires the analyst to employ judgment in estimating: (1) the risk-free rate, (2) the utility's beta and (3) the market risk premium.

The approach used by FEA resulted in an estimated cost of equity of 12.9% to 15.6%.

Edison argues that the data used by FEA to estimate the risk-free rate, beta and the market risk premium, are drawn from very different time periods. Edison notes that FEA used a short-term Treasury bond rate, betas calculated over 5-years, and a market risk premium estimated over more than 50 years. Edison contends that this results in a complete misspecification of the CAPM with unknown and unknowable impacts on the model results.

4. Price/Book Test

Edison included a market-to-book analysis in its showing purely as a check of the reasonableness of its Risk Premium and DCF analysis. Because of unstable historic recorded returns, Edison used an approach based on 1983 recorded data to derive an estimated return on common equity of 14.6%-17.6%.

Both FEA and staff contend that Edison's analysis has no merit.

5. Comparable Earnings Analyses

Edison declined to provide the usual Comparable Earnings Test because, according to Edison, the returns earned by electric utilities have not been adequate for nearly a decade. Instead Edison, as a test for reasonableness, used the Risk Premium and DCF methodologies applied to the required return for Moody's double-A electric utilities.

FEA provided an analysis of the allowed rates of return on common equity of other electric utilities throughout the country. FEA does not suggest that the Commission should adopt the average allowed rate of return of other electric utilities, but merely suggests that, taking into consideration the trends in allowed rates of return over time and risk differences among companies, allowed rates of return are important in forming reasonable expectations regarding rates of return on common equity that comparable companies are likely to achieve. According to FEA the comparative returns indicate that Edison's request is too high.

6. Risk

In supporting its request for 16.75 percent return on common equity, Edison argues that it faces risk arising both from financial and economic uncertainties, and from conditions which are specific to the Company.

With respect to financial and economic uncertainties, the Company cautions against giving undue weight to the recent drop in interest rates, pointing out that numerous respected financial analysts expect interest rates to rise significantly in 1985 and 1986. Edison also points out that the massive federal deficit is projected to persist, with consequent upward pressure on interest rates.

With respect to the conditions of risk which are specific to Edison, the Company's position is that although the types of risk which it faces today differ in part from those two years ago, the overall level of risk has not declined and is in several significant areas greater. Edison states that in evaluating the overall level of risk of a particular company investors consider regulatory climate, quality of management, fuel costs and associated risk, nuclear investments, and other factors specific to that

company. Edison points out that since its last general rate case decision in 1982 this Commission has implemented, or considered, certain regulatory procedures which investors consider to have increased the uncertainty of recovery of the Company's operating and capital costs.

One of the procedures referred to by Edison is the implementation of the Target Capacity Factor (TCF) at San Onofre Units 2 and 3. Edison argues that from an operational standpoint the TCF adopted by this Commission is negatively skewed, with the chance of incurring a penalty much greater than receiving a reward. Edison contends that the TCF ignores the fact that the number of full-power days per operating cycle for the first three refuelings limit the maximum potential production to an 85 percent capacity factor. Edison further contends that such a capacity factor would require operation at a 100 percent capacity factor during the full scheduled operating period which the Company considers unrealistic. Edison's conclusion is that there is substantially more risk in the operations of San Onofre Units 2 and 3 than there would otherwise be if the TCF penalty provision was capped, if the TCF reflected initial core operation, and if the TCF's deadband was in the 55 to 75 percent range for operation after the initial core is exhausted.

Edison identified other risks as the future rate treatment for San Onofre Unit 1 and the hearings on the reasonableness of construction costs for San Onofre Units 2 and 3. Edison also notes that events around the country in the last two years relating to nuclear plants under construction suggest that from an investor point of view, the risk associated with the Company's investment in Palo Verde Units 1, 2, and 3 is substantially greater

than could have been foreseen when the last general rate case was decided. Finally, Edison contends that the expansion of the Annual Energy Rate (AER) from 2 to 10 percent also has operated to increase the uncertainty of recovery of fuel-related operating costs, with consequent increase in risk as perceived by investors.

FEA evaluated the relative riskiness of Edison in comparison to a group of 24 double A-rated electric utilities on the basis of financial risk and business risk.

FEA evaluated financial risk on the basis of proportion of debt in the company's capital structure. The higher the proportion of debt, or conversely the lower the proportion of common equity, the greater the financial risk. Compared to a group of double-A rated electric utilities, FEA concludes that Edison would be judged to be about average risk with respect to financial risk.

FEA defines business risk as the uncertainty involved in the projections of future operating income. As one indicator of business risk FEA examined the volatility of returns on common equity for a group of double-A electric utilities over the 1972-1983 period. On this basis FEA judged Edison about average.

According to FEA, based on other measures of risk such as Value Line's ratings, Edison's beta approximates the group average, its safety rank is below average, but its financial strength rating is better than 22 of the 24 other double A-rated companies. FEA contends that these indicators are further support for its conclusion that with respect to financial risk, Edison is about average.

Edison argues that, as demonstrated during cross-examination, FEA made a mathematical error in its analysis. However, after correcting for the error, Edison's coefficient of variation is substantially above the group's average coefficient of variation. Edison points out that this indicates that compared to the average of the comparable group, Edison is riskier.

Notwithstanding FEA's and Edison's position, we do not place much weight on measuring risk based on book returns on equity. It would seem that a better measurement would be to assess the volatility in market returns.

In contrast to FEA's evaluation, which is based only on published financial indices and reports, staff's evaluation of the relative risk of Edison is more company specific.

Staff argues that in addition to the highly favorable economic picture for the test period, the Commission must objectively scrutinize the regulatory environment in which the utility operates, with particular attention to the regulatory mechanisms which have a direct impact upon risk. Included among these are the Energy Cost Adjustment Clause (ECAC) which protects the utility from the variability of fuel costs; the Electric Revenue Adjustment Mechanism (ERAM) which insulates the utility from the vagaries of electric system sales; the Commission's Rate Case Plan (RCP) and the Attrition Rate Adjustment (ARA) mechanism, which insure timely processing of utility rate cases and recovery of utility costs through rates; the Major Addition Adjustment Clause (MAAC) procedure which provides timely rate recognition for major capital projects. All of these devices have been created by the Commission to address problems associated with the vast changes that the energy utility business has experienced in the last decade. These devices, staff notes, have also served to mitigate the risks associated with the energy utility enterprise.

According to staff, not the least significant factor to consider is Edison's recent financial performance. Staff notes that earnings in 1983 were at record levels for the third straight year. Staff further notes that over the same 3-year period (1981-1983) Edison's earned return on equity was at or above that authorized by the Commission.

Staff further argues that a substantial degree of risk is removed from Edison's future by reason of the completion of construction, licensing and commercial operation of San Onofre Nuclear Generating Station (SONGS) Units 2 and 3. More importantly, staff notes, Edison is receiving base rate MAAC revenues from SONGS 2 and 3 to the tune of nearly $500 million (D.83-09-007, D.83-11-91, and D.84-03-059 in A.82-02-040). According to staff, the fact that Edison has managed to bring the SONGS units on-line during this difficult period of nuclear plant cost escalation, refittings, cancellations and defaults and receive interim rate recognition from this Commission is a major accomplishment, one that reduces Edison's risks vis-a-vis other utilities with nuclear projects under construction.

Further, staff submits that the completion of SONGS 2 and 3 has many other salutary effects. According to staff, the major decrease in construction expenditures diminishes Edison's appetite for capital, it reduces the need for external borrowings, it permits growth of Edison's equity capital ratio, which tends to make a greater percentage of earnings available for payment of dividends, it improves the company's cash flow and interest coverages, and it results in improved quality of earnings since non-cash Allowance for Funds Used During Construction (AFUDC) becomes a smaller proportion of Edison's net income.

Regarding the question of safety of the shareholders' investment, staff argues that, the commercial operation of the SONGS units is a crucial milestone for Edison and is the single most important development within the company bearing upon risk since the last general rate case. Staff notes that in public pronouncements, Edison's management point with pride to the completion of SONGS 2 and 3 as a major accomplishment which has immeasurably strengthened the company:

> "In the face of the most difficult nuclear licensing and construction period in the history of our nation, which is threatening the financial integrity of many utilities completing nuclear facilities, your Company experienced a successful year and strengthened its ability to meet its public service responsibility to customers and its financial stewardship to shareholders." (Letter to Shareholders, Southern California Edison Company's 1983 Annual Report, p.5.)

According to staff, these indications of strength impact directly on the safety of SCE's shareholders' investment and diminish rather than increase, the risk associated with that investment. Therefore, staff submits these qualitative indicators all point to a reduction in the cost of capital.

7. Discussion

In evaluating the recommendations presented by the witnesses, we have carefully examined all the quantitative and qualitative analyses presented in this case.

Turning first to the question of the future cost of long-term debt, at the outset of these hearings, both Edison and staff estimated 12% yields for 1985 and 1986 on double-A rated public utility bonds. FEA and Shareholders noted that this rate understated the rates observed in the marketplace. Subsequently during the updating hearings in September 1984, Edison stated there was no indication that rates would decline to 12% as hoped and based on various forecasts by the investment bankers, revised its estimate to 14% for 1985 and 13% for 1986.

We agree with FEA and Shareholders that based on the latest observations in the marketplace 12% is low. However, we find Edison's forecast of 14% for 1985 high. While we do not place reliance on any particular forecasting service, consideration of the updated forecasts along with other current information, leads us to conclude that a rate of 13% for 1985 and 1986 represents a more reasonable estimate of Edison's incremental debt costs in the test period. For 1984, actual debt costs will be used. These costs will be applied to the 1985, and 1986 projections of Edison's financings, presented in late-filed Exhibit 156, p. 4.

Turning to the cost of common equity, the Commission's objective is to authorize a return to common equity owners that will be commensurate with the market returns on investments having corresponding risks during the test period. We believe that, in establishing an authorized return which appropriately reflects the market cost of capital, we are placing utility management on a sound financial footing in terms of competing for and attracting capital. This does not mean, however, that Edison or any utility will necessarily earn its authorized rate of return during the test year--that depends on the ability of Edison's management to effectively and efficiently utilize its resources over both the short- and long-term, and the reasonableness of the expense estimates and allowances for the test period.

The task before us, then, is to estimate the cost of Edison's capital, in particular the cost of equity capital, in the market over the next three years. To do so, we must identify the risks for which investors require compensation, evaluate the relative magnitude of these risks for Edison over the test-year period, and quantify these observations into an authorized rate of return on common equity and total capital. We are guided by the following three major considerations, which were set forth by the Commission in D.83-12-068, PG&E's test year 1984 general rate case decision.

"First, we believe that, all other things being equal, the cost of equity capital varies in the same direction as changes in the general level of inflation and interest rates. Although the absolute magnitude of that relationship or 'risk premium' is an issue of controversy, the general principle is not only consistent with financial theory, but also acknowledged by this Commission and the parties to this and prior rate of return proceedings. Second, we recognize that the market cost of equity capital for a particular utility reflects other risks, such as the exposure of a utility's earnings to variability in fuel costs, sales levels, as well as uncertainties regarding the technical feasibility and/or cost recovery of prior capital investments. Hence, our determination of an appropriate rate of return must also take into consideration the extent to which these risks have abated, increased, or remained unchanged, and the probable direction of change during the test year period.

"Finally, we believe that the judicious application and intepretation of financial models can aid us in quantifying the overall balance of these risks, and the market cost of equity capital during the test period. It must be emphasized, however, that the models themselves may not accurately reflect all of the intricacies of financial markets. Further, the assumptions used in applying a financial model or formula must be carefully evaluated for reasonableness before this Commission places substantial weight on the numeric results." (D.83-12-068, mimeo. p. 10.)

Keeping the above in mind, we will first review the testimony based on financial models. A tabulation of the various analyses submitted by the witnesses is set forth below:

Quantitative Analysis
Return on Equity

Method	Edison %	Staff %	FEA %	Shareholders %
DCF Company Specific:				
Average Price	17.0	15.20-15.75	15.5-16.0	-
Spot Price	-	-	15.8-16.3	-
DCF Double A Electrics:				
Average Price	16.1	15.24-15.22	14.25	-
Spot Price	-	-	14.61	-
Risk Premium	18.7	-	16.0-16.2	17.0-17.5
CAPM	-	-	12.9-15.6*	-
Price/Book Test	16.1	15.25-15.75	-	-
Comparable Earnings	-	-	13.1-13.6	-
Final Recommendtion	16.75	15.25-15.75	14.6-15.8	17.0-17.5

*Provided with reservations.

The witnesses basically used either the Discounted Cash Flow (DCF) model or the Risk Premium model, or both, to develop their recommendations. Other techniques (Market/Book Ratio, Comparable Earnings Analysis, Capital Asset Pricing Model) were used as a check upon the results of the models by some of the witnesses, but the DCF and risk premium models were the primary tools employed.

Regarding Edison's Risk Premium Analysis, we find the application of theory reasonable, yet are not convinced, considering the result obtained that use of the long period of premiums does resolve the problem of extreme volatility in the historical data, which was one of Edison's criticisms of FEA's risk premium approach.

Consequently, we have reservations regarding Edison's average risk premium considering this average is based on past premiums ranging from approximately -20.00% to +50.00%.

Unlike Edison, FEA in its Risk Premium Analysis, uses the DCF model combined with treasury bond rates and double-A utility rates to calculate a "prospective" risk premium. This approach tends to mitigate the volatility of the premiums (versus calculating recorded premiums). We note the FEA witness has reservations about this approach and will give it appropriate weight in our final determination.

Regarding Edison's DCF analysis, we note that it relies solely on financial analysts' forecasts of dividend growth and there is no insight into what these forecasts are based upon, especially time horizon and earnings growth assumptions to support dividend growth. We recognize that an assumed growth rate averaging 7%, assuming Edison's retention rate of 37.5%, implies a return on equity of 18.67%, which seems unreasonable considering Edison's revised request of 16.75% and Edison's relative risk since its last rate case decision.

However, we note that the lower end of the range yields a DCF return on equity of 16% which we consider is in the reasonable range.

The staff's DCF analysis, we conclude, is somewhat biased towards a lower return on equity because of the growth rate developed from its "comparable" utilities. Nevertheless, the staff's analysis is useful, although it may not appropriately recognize company-specific risk for Edison. On the other hand, we do not entirely agree with Edison's criticism about the noncomparability (with

Edison) of the 24 utilities used in staff's DCF analysis. We agree that staff's use of bond ratings, common stock betas and equity ratios, as measures of risk is reasonable; however, use of comparable utility data for calculating company specific cost of equity may not fully reflect the company specific components.

We find FEA's DCF analysis most useful. While staff's and FEA's DCF analyses provide comparable results, FEA's analysis appears to better reflect the risk factor for Edison as evidenced by the results of its Company Specific and its Double A Electrics approach. We do not give much weight to FEA's CAPM analysis and Comparable Earnings test.

Regarding Shareholders Risk/Premium Analysis, we share staff's criticism of the averaging of three different premiums from three different time periods. Also, we have reservations regarding the theoretical appropriateness of this approach. We conclude that Shareholders Risk/Premium Analysis is a earnings/price ratio for each year on recorded earnings and it produces results which do not reflect realistic market expectations.

On the subject of risk, we have to disagree with staff that simply because San Onofre Units 2 and 3 are operational, Edison's problems have disappeared. Edison has the burden of keeping these plants on line and that responsibility cannot be lightly dismissed, particularly in light of our recent decision on A.82-02-40 where we adopted a target capacity factor without any earnings cap beyond a 50-50 sharing of risk outside the established dead-band. Finally, Edison is still facing Commission scrutiny in our upcoming reasonableness review for the recovery of investment-related costs. However, we agree with staff that Edison has less need for external borrowings and cash flow and interest coverages should improve.

Finally, we note that economic and market conditions (inflation and interest rates) have remained fairly stable since the last general rate case decision when Edison was allowed 13% for new debt and granted a return on equity of 16%.

There is no precise method of quantifying and incorporating all the above considerations into a specific return on equity. However, in this case we do believe that a reasonable return lies within the 15.5% to 16% range.

E. Adopted Rate of Return

After weighing the evidence in this proceeding, we are of the opinion that keeping Edison at a 16.00% return on common equity is reasonable. This results in a rate of return on rate base of 12.70% for 1985 which will enable Edison to attract the necessary capital to provide reasonable service at reasonable rates to its customers. We believe that our adopted rate appropriately captures the market trends and financial risk of Edison over the next three years. In making our deliberations, we specifically considered the emerging trend of our regulatory policies to increase risk sharing between shareholders and ratepayers.

The following table sets forth the adopted rate of return which assumes that all new long-term debt for 1985 and 1986 will sell at an interest cost of 13%. Since no new preferred stock will be issued we will reflect the imbedded cost.

Adopted Rate of Return

Test Year 1985

Component	Capital Ratio	Cost Factors	Weighted Cost
Average Year 1985	%	%	%
Long-Term Debt	45.0	10.40(a)	4.68
Preferred Stock	10.0	8.17	.82
Common Stock Equity	45.0	16.00	7.20
Total	100.0%		12.70

Attrition Year 1986

Average Year 1986			
Long-Term Debt	45.0	10.25(a)	4.61
Preferred Stock	10.0	8.17	.82
Common Stock Equity	45.0	16.00	7.20
Total	100.0%		12.63

(a) Exhibit 156, p. 4

After Tax Interest Coverage 1985

$$\frac{12.70}{4.68} = 2.71 \text{ times}$$

After Tax Interest Coverage 1986

$$\frac{12.63}{4.61} = 2.74 \text{ times}$$

IV. RESULTS OF OPERATIONS

A. Escalation

1. Historical Escalation

In order to compare recorded expense levels over several years, it is necessary to adjust the recorded data for the effects of inflation in the various years. Therefore, recorded and estimated expenses are adjusted to base year dollars so that comparisons of expense levels over time can be made on a comparable basis. Differences in adjusted historical expenses occur as a result of the use of different rates in escalating prior years' recorded expenses to the base year. In this case, 1982 was generally used as the base year.

The difference between Edison and staff due to historical escalation amounts to a net downward adjustment of $62,000 to Edison's estimates. Certain accounts adjust upwards and others downwards. The reason for the dollar difference is that staff disagreed with Edison on a few of the various components that make up the historical escalation rate.

The historical escalation rates are generally developed by averaging various published indexes of wages and prices. These indexes are weighted differently before being averaged, depending upon the specific services or materials which each index represents. The weighting process ensures that the average of various indexes accurately represents the "bundle" of services and materials for which expenses have been and will be incurred. The weighting process involves judgment in the selection of a weighting method, and reasonable persons may disagree with respect to the selection of particular indexes.

Because such disagreement usually concerns relatively few of the indexes, the dollar differences which result from different historical escalation rates tend to be negligible. We believe it is advantageous from the perspective of regulatory efficiency for parties to agree to specific historical escalation rates in advance, thereby eliminating the need to litigate and track a multitude of minor adjustments. We should note that the same inconvenience was experienced in PG&E's general rate case and here again, the magnitude of difference was about the same. This leads us to conclude that all the complications introduced during the rate case proceeding as a result of the utility and staff using differing historical escalation rates are not justified. Unless there are serious disagreements, we expect Edison and staff to resolve such minor differences at the NOI stage. Therefore in future general rate case proceedings, we expect agreement on this issue before final estimates are presented.

For the sake of expediency and since the differences will get "lost in the rounding", we will adopt Edison's historical escalation rates for purposes of this proceeding.

2. Future Escalation

a. Labor

Edison and staff assumed different labor escalation rates, as illustrated below:

Comparison of Edison and Staff Labor Escalation Rates

	Edison	Staff
1983	6.0%	6.0%
1984	5.7%	5.5%
1985	6.4%	5.5%

Edison bases its labor escalation rates on the forecsted changes in the Index of Compensation per Hour (Non-Farm Business Sector).

Staff recommends that the negotiated union contract percentage increase be used.

Edison argues that the staff recommendation does not reflect the average wage increase for all employees since the union wage agreement is applicable to only about one-half of Edison's employees. Also, Edison argues that the union wage agreement alone does not address a number of labor cost items which are also negotiated. Among these labor cost items are overtime and holiday pay, vacations, foreman's compensation, shift differential pay, and compensation for board, lodging, transportation and travel time. Edison contends that its average wage does increase at 1.10 - 1.11 times the CPI-U or Edison's union wage agreement.

We conclude that since Edison has the opportunity to control the increase of nonunion wages and the other items mentioned, we see no reason to allow a greater rate of increase for these items than that allowed under Edison's union wage agreement. Accordingly, we adopt the staff recommendation.

Turning to the attrition years, as recommended by staff in Exhibit 83, if a contract percentage increase has been negotiated, we will use that rate as the labor escalation factor if it appears reasonable. On the other hand, if the contract escalation factor appears to be unreasonably high, or no contract agreement has been reached, we will use the DRI forecasted consumer price index (CPI-Urban) as the labor escalation factor.

b. Non-Labor

Pursuant to the Rate Case Plan, Edison updated its forecast of non-labor escalation rates. Edison and staff are in agreement on the methodology used to develop the non-labor escalation rates, and further agree with respect to the 1983, 1984, and 1985 rates recommended for adoption in this case, as shown below:

Recommended Non-Labor Escalation Rates

	Edison	Staff
1983 (recorded)	2.92	2.92
1984 (estimated)	2.87	2.87
1985 (estimated)	4.49	4.49

These rates were based upon the DRI Control Forecast dated August 25, 1984, which was published in September, 1984.

We will adopt the above rates.

B. Sales and Revenue

For 1985 total sales, Edison forecasts 64,095 GWh while staff forecasts 65,201 GWh, staff being 1106 GWh or 1.7% higher than Edison. This difference translates to a jurisdictional revenue requirement at "present rates" of $46.7 million.

1. Sales

Both Edison and staff presented revised sales forecasts for test year 1985. A comparison of the Edison and staff forecasts and the adopted figures are presented below. Differences occur only in the Residential, Industrial, and Other Public Authorities Revenue Classes. We will discuss these differences.

1985 Average Year Sales Forecast
(Millions of kWh)

Revenue Class	Edison	Staff	Adopted
Residential	18,300	19,052	18,300
Agricultural	1,000	1,000	1,000
Commercial	18,950	18,950	18,950
Industrial	16,600	17,004	16,757*
Public Authorities-Other	4,650	4,600	4,650
Resale	3,960	3,960	3,960
Net Edison	63,460	64,566	63,617
Resale-Special	635	635	635
Total	64,095	65,201	64,252

* 15,643 x 1.035 x 1.035

2. Sales Forecasting Methodology

Both Edison and staff forecast kilowatthour sales separately for each of the above Revenue Classes. Sales are forecast utilizing econometric models which relate sales to the following key economic or demographic variables: (1) economic indicators, (2) customer growth, (3) conservation, (4) electricity prices, and (5) weather conditions. The forecasts are adjusted to reflect new conditions such as closure or re-opening of large industrial facilities, installation of new cogeneration facilities, and recent trends in recorded sales data.

While Edison and staff used a similar forecasting method, staff updated its estimate by making percentage adjustments to reflect staff's perception of growth in sales trends based on the most recent recorded figures. The differences are discussed below:

3. Residential Sales

Edison's updated forecast for 1985 residential sales is 18,300 GWH, while staff is 752 GWH or 4.1% higher at 19,052 GWH.

Edison argues that one way to check the reasonableness of a sales forecast is to compare the forecast growth rate to recent growth rate trends. Edison emphasises that in the case of residential sales, which have significant heating and air conditioning loads, it is necessary to adjust recorded data to normal-weather before making comparisons in order to remove any weather-induced bias.

Edison notes that compared to recorded 1983 sales, its updated forecast yields an average growth rate between 1983 and 1985 of 3.2 percent per year. However, if the 1983 residential sales level is normalized to average weather conditions, then the forecast yields an average growth of 3.5 percent per year over the normalized 1983 sales.

In comparison, Edison notes that staff's forecast yields an average growth rate of 5.3 percent per year from 1983 to 1985, or 5.6 percent per year when starting from a weather-normalized 1983 basis.

According to Edison, on a recorded basis, July 12-month ended sales grew 6.4 percent over the previous 12-month period. However, after the data is normalized to average weather, 12-month ended residential sales grew only 3.6 percent. If instead of 12-month ended, the year to date sales through July 1984 are considered, the growth is almost the same--3.4 percent, weather-adjusted.

Thus, Edison argues that on a weather-adjusted basis, its forecast of a 3.5 percent growth rate closely reflects recent growth trends of 3.4 percent to 3.6 percent per year growth, while the staff forecast of 5.6 percent per year growth over estimates recent trends. The forecasts are set forth below for comparison.

Comparison of Residential Energy Sales
(Growth Rates Based on Weather-Adjusted Recorded Data)

Growth Rates, As of July, 1984		Forecast Average Annual Growth Rates	
12-Month Ended	Year-to-Date	Edison	Staff
3.5%	3.4%	3.5%	5.6%

While staff correctly points out that recent recorded non-adjusted residential sales show unusual growth, we agree with Edison that test year residential sales estimates should generally be prepared on a weather normalized basis. Therefore, we will adopt Edison's estimate for purposes of this proceeding.

4. Industrial Sales

The Edison forecast for 1985 industrial sales is 16,600 GWh. The staff forecast is 17,004 GWh, which is 404 GWh (2.4%) higher than the Edison forecast.

Edison argues that, as in the residential sector, one test of reasonableness is to compare the forecast growth rate to recent trends. When compared to 1983 recorded industrial sales of 15,643 GWh, the Edison forecast of 16,600 GWh yields an average annual growth rate from 1983 to 1985 of 3 percent. (There is no significant weather adjustment to be made in the industrial sector.) When similarly compared, the staff forecast of 17,004 GWh yields an average annual growth rate of 4.3 percent. On a 12-month ended basis through August, 1984, the recorded Edison industrial sales grew 3.5 percent over the previous 12-month period.

Compared to the recent growth trend of 3.5 percent, Edison projects a 2-year (1983 to 1985) average growth rate of 3.0 percent, while staff projects a 2-year average of 4.3 percent. These rates are set forth below:

Comparison of Industrial Sales Growth Rates

Growth Rates		Forecast Average Annual Growth Rates	
12-Month Ended August, 1984	Year-to-Date (June, 1984)	Edison	Staff
3.5%	3.5%	3.0%	4.3%

Edison argues that its industrial sales forecast, which predicts a slowing in the growth rate, is consistent with the economic outlook of a lower growth rate in 1985 than in 1984.

On the other hand, we note that staff expects some increase in the growth rate.

While there are indications of a slowdown in growth of the economy, we conclude that Edison is being unduly pessimistic regarding the effect of the slowdown on energy sales. On the other hand, we find the staff forecast overly optimistic. We consider it reasonable, for purposes of this proceeding, to use the current 3.5 percent average annual rate of growth. On this basis, the adopted estimate for industrial sales is 16,757 GWh.

5. Other Public Authority Sales

The Edison forecast for OPA sales is 4,650 GWh, 50 GWh higher than staff's forecast. We will adopt the Edison estimate.

6. Annual Major Additions Rate (AMAR) Level

The issue is whether AMAR should be included in base rates because of rate design considerations and the Commission's stated goal of designing rates as close as possible to marginal cost. Updated estimates of revenue at present base rate levels plus revenue at present AMAR level were also provided by Edison and staff. AMAR relates to the non-investment-related costs of San Onofre Units 2 and 3. Edison and staff used the same AMAR rate levels. Currently AMAR is treated as a separate offset and is not part of the rate design for base rates.

Edison notes that revenue at present base rate levels plus revenue at present AMAR level is estimated by adding the revenue at present base rate levels to the revenue at present AMAR level, by rate schedule. Edison further notes that should the Commission wish to include in their decision a rate design change which would combine the revenues associated with AMAR into base rates, the base rate levels need to be re-designed to take into account the various minimum charges, voltage discounts, and other base rate level-related charges since the AMAR, as an offset, is not subject to these adjustments, and therefore cannot simply be added to the current present base rate levels.

We agree with Edison and conclude that AMAR should be included in total revenues for base rate design, since excluding these revenues causes distortion from true marginal cost based rates.

7. Revenue At Present Rates

Present base rate revenues are the revenues which are estimated to be billed for service rendered during test year 1985 absent the rate relief requested in this application. ECAC revenues, MAAC revenues, and Conservation/Load Management Adjustment Clause (CLMAC) revenues are not reflected in present base rate revenues.

Estimates of present base rate revenues were presented by Edison and Staff.

Staff's estimate of present rate revenues is approximately $46.7 million higher than Edison's estimate. This difference is largely a function of the differences between Edison and staff with respect to forecasted kWh sales as previously discussed, however, there are other factors called "billing determinants" which do impact the revenue calculation to a lesser extent.

The calculation of revenues from the sales estimate relies upon judgment and computer models which simulate usage patterns and customer data. As part of this methodology it is necessary to develop appropriate billing determinants for each rate schedule.

In this regard there was a difference between Edison and staff due to: (1) Rate Schedules Nos. D and DE because of different estimates of kWh sales and bill months; (2) Rate Schedule No. GS-1 because of different estimates of kWh sales; and (3) Rate Schedules Nos. GS-2 and TOU-8 because of different estimates of kWh sales and kilowatt-months. We have discussed the estimates of kWh sales but did not address the question of billing months. The reason for staff's disagreement on this point is unclear. Therefore, we will adopt Edison's method of calculating billing determinants for the sake of expediency.

Edison requests that this opinion set forth the adopted billing determinants, so that a check could be made on whether the adopted rates will generate the adopted revenues. To accommodate Edison's concerns, the workpapers (provided by staff), which calculate the revenue requirement adopted in this opinion, will be included in the formal file and become part of the record in this proceeding. These workpapers will be available for inspection by the parties.

Staff's updated estimate of revenue at present base rate levels plus revenue at present AMAR level for the Five Major Customer Groups is approximately $46.7 million higher than Edison's estimate. The differences in updated revenue at present base rate levels plus revenue at present AMAR levels are set forth by Customer Group in the table below.

Difference Between Edison and Staff
Updated Revenue at Present
Base Rate Levels Plus Revenue
At Present Amar Levels
($000)

	Edison Estimate	Staff Estimate	Staff Exceeds Edison ($000)	Staff Exceeds Edison (%)
Five Major Customer Groups				
Domestic	827,761.3	862,341.2	34,579.9	4.2
Lighting-Small & Medium Power	875,770.2	879,497.8	3,727.6	0.4
Large Power	700,087.8	708,440.2	8,352.4	1.2
Agricultural & Pumping	71,098.4	71,098.4	0.0	0.0
Street & Area Lighting	50,363.4	50,363.4	0.0	0.0
Subtotal-Five Major Customer Groups	2,525,081.1	2,571,741.0	46,659.9	1.8
CPUC Jurisdictional Other				
Fringe	297.1	297.1	0.0	0.0
MWD	6.5	6.5	0.0	0.0
OOR	27,117.6	27,814.0	0.0	0.0
Subtotal-Other	28,117.6	28,117.6	0.0	0.0
CPUC Jurisdictional Total	2,553,198.7	2,599,858.6	46,659.9	1.8
Resale				
TOU-R	125,150.0	125,150.0	0.0	0.0
Resale-Special	1,270.0	1,270.0	0.0	0.0
OOR	14,390.0	14,390.0	0.0	0.0
Subtotal-Resale	140,810.0	140,810.0	0.0	0.0
TOTAL	2,694,008.7	2,740,668.6	46,659.9	1.7

Source: Exhibits 170 and 171.

The adopted revenue, based on the adopted sales estimate, is set forth in the Summary of Earnings contained in Appendix B.

C. Operating Expenses

Operating expenses are all costs associated with operating the utility, including the cost of operating and maintaining the utility's facilities.

1. Nuclear-Related Expenses

Nuclear related expenses were treated as a separate phase in this proceeding. Therefore, separate expense estimates were developed by Edison and staff to cover these nuclear-related items: Nuclear Power Production Expense; Transmission Expense; Administrative and General Expense; and Tax expense.

Pursuant to a Stipulation on September 17, 1984, staff, Edison and SDG&E agreed to recommend that the Commission adopt the O&M and A&G expense estimates for San Onofre Unit Nos. 1, 2, and 3 (stated in 1982 dollars) for 1985, 1986, and 1987 described in the Stipulation, in lieu of litigating the issues related to those estimates in this proceeding.

As noted in the Stipulation, Edison and SDG&E do not concede that staff's proposed adjustments to Edison's estimates are correct or valid, except that staff, Edison and SDG&E agree regarding the appropriate methodology for determining Payroll Tax expense. While agreeing to accept the staff-recommended O&M and A&G expense levels, Edison and SDG&E do not concede that the O&M and A&G expense levels developed by staff and recommended to the Commission, represent either the best estimate of such expenses for Unit Nos. 1, 2, and 3 in 1985, 1986, and 1987, or the O&M and A&G expense levels which will actually be required to operate and maintain Unit Nos. 1, 2, and 3, in 1985, 1986, and 1987. The Stipulation was made solely for the purpose of expediting hearings in this proceeding.

Accordingly, Edison recommends that the Commission adopt (1) the level of O&M (excluding refueling) and A&G expense estimates; (2) the refueling expense estimates; (3) a methodology for determining the 1985, 1986, and 1987 O&M, A&G, and Payroll Tax expense levels based on the expense estimates described in (1) and (2) above; and (4) a methodology for determining SDG&E's level of O&M and A&G expenses for its 1988 Attrition Year, all as described in the Stipulation which is part of the record in this proceeding.

We commend Edison for the spirit of cooperation it has shown throughout this proceeding. Edison was helpful in expediting hearing on the many complex issues and thereby saving valuable time. We conclude that the stipulation is reasonable and should be adopted.

a. Depreciation Expense

Edison's estimate of nuclear depreciation expense including decommissioning for 1985 is $17,027,000 as compared to Staff's estimate of $16,767,000. The difference between Edison and staff of approximately $260,000 is due to the methodology used in developing an interim retirement rate for Account 325, Miscellaneous Power Plant Equipment.

Edison computed the interim retirement rate for this Account at one percent, based upon recorded data. On the other hand, staff proposes an interim retirement rate of one-fourth of one percent, which appears to be based solely on staff's judgment. Edison argues that its proposed interim retirement rate is supported by historical data and, in Edison's opinion, is more reasonable.

We conclude that Edison's one percent retirement rate should be adopted since this rate is supported by historical data.

b. Rate Base

In Edison's original application, Edison included $124 million of direct costs for San Onofre Unit No. 1 in Construction Work in Progress (CWIP). This amount was included in plant additions projected

to be completed and included in rate base as of mid-1983. During hearings in the nuclear phase of this proceeding, Edison revised its estimate of the direct Unit 1 CWIP to $113,507,000 with a projected completion date of year-end 1984 to reflect the latest available information at that time. With the inclusion of other indirect costs and an Allowance For Funds Used During Construction (AFUDC), the present estimate of the Unit 1 investment to be included in rate base is $145,556,000.

During the nuclear phase of this proceeding staff testified that because it had not had an opportunity to evaluate the work performed by Edison, the investment should not be accorded rate base treatment until staff can perform such an evaluation in the San Onofre Unit No. 1 Order Instituting Investigation (OII) proceeding.

On receipt of staff's testimony, Edison suggested a proposal for interim ratemaking treatment to accommodate the concerns expressed by staff that it be given the opportunity to review these costs. According to Edison, its proposal allows staff an opportunity to conduct a review of the Unit 1 investment, and further would deny any cash rate relief until the Commission issues a decision approving recovery of these costs. Edison's proposal for interim ratemaking treatment is that:

> "...the Commission grant Edison authority to establish a Specified Major Addition in its Major Addition Adjustment Clause ("MAAC") and to accrue the revenue requirement associated with the SONGS 1 investment as of the date that the unit achieves full power operation and satisfies the Commission's criteria for restart, and continue in effect until such time that the Commission determines the reasonableness of the investment in SONGS 1 and thereby sets base rates pursuant to a Commission decision in the SONGS 1 OII."

Because staff had considerable doubts regarding the operation of SONGS 1, staff believes that:

> "...until there is some assurance that SONGS 1 will not only return to service for the first refueling, but continue in service, that the ratepayer should not be at risk for the Company's full rate of return".

As a counter-proposal, staff recommends that the SONGS 1 investment receive AFUDC treatment until a decision is rendered by the Commission in the San Onofre Unit 1 OII as to the prudency of the expenditures at issue.

Edison argues that the staff proposal is punitive since Edison is not provided an opportunity to earn its authorized rate of return on the retrofit investment once Unit 1 resumes full power operation. Edison points out that in the best of circumstances, the company would only be allowed to recover a lesser amount equivalent to AFUDC on its investment (as if the investment were still in CWIP) until the Commission issues a final decision on the reasonableness of the investment in Unit 1. Edison further points out that this would occur despite the fact that the Commission may eventually determine that the costs were reasonably and prudently incurred and the plant returned to service as currently projected.

Edison notes that once Unit 1 resumes full power operation, Edison will close the current Unit 1 CWIP balance to plant in service, since the plant will be used and useful. As of that date, under FERC accounting rules, Edison must cease accrual of AFUDC for financial accounting purposes and begin treating the investment as plant in service. That is, Edison must record current period depreciation accruals and accrue taxes which will be assessed against the property.

Edison further argues that under the staff proposal Edison's investors will receive only a return on investment in accordance with the AFUDC rate (currently 10.24 percent), as opposed to the rate of return on investment which the Commission will ultimately authorize in this proceeding. During the interim until the Commission issues a final decision on the reasonableness of the investment, Edison's investor will be permanently disadvantaged by the amount of the property taxes accrued and the differential rate of return on the investment which Edison incurs. According to Edison, under the staff proposal, there is no mechanism for ever compensating the company for these losses and staff has no proposal for making Edison's investors whole if the Commission finds that all or a part of the Unit 1 investment is reasonable.

We note that the Edison proposal is generally identical to the procedure which the Commission has authorized in D.83-09-007 in the MAAC proceeding. We further note that Edison's proposal affords the staff adequate opportunity to review the investment in Unit 1 and make the appropriate recommendations as to the appropriate investment amount for inclusion in rates, provides the ratepayer with adequate protection on that portion of the Unit 1 investment which may ultimately be determined by the Commission to have been unreasonable or unreasonably incurred, and protects the investor from erosion of the opportunity to earn a reasonable return on his or her investment. Accordingly, we conclude that the Edison proposal, which accrues all costs in a memorandum account rather than a balancing account, until such time as the Commission issues a decision, is reasonable and should be adopted.

2. Steam Production Expense

One of the significant issues in this proceeding is the staff recommended adjustment to Edison's Steam Production Expense estimate for test year 1985. In 1982 dollars, Edison requested $188 million, staff recommends $169 million.

All expenses are stated in 1982 dollars unless otherwise noted. The adopted levels of expenditure for the test year will be increased by the escalation factors discussed previously.

The differences between Edison and staff and the adopted levels of expenditure are set forth in the following table:

Steam Production Expense
(Thousands of 1982 Dollars)
Test Year 1985 - System Expense

Issue	Edison	Staff	Adopted
Estimating Methodology			
Steam Adjustment Factor	157,737	140,922	144,850
Rents	218	214	218
Adjustments			
Fuel Oil Pipeline Deprec. Expense	4,815	4,512	4,516*
Duplicate Expenses - Redondo Beach	243	0	243
Coal Write-off	34	34	34
Fuel Tank Lease	3,068	3,068	3,068
Property Damage Est.	5,185	5,185	5,185
Research, Development and Demonstration	15,989	14,349	15,514
Subtotal	29,334	27,148	28,560
Uncontested	692	692	692
Total	187,981	168,976	174,320

*Reflects staff correction.

a. Steam Adjustment Factor

Edison developed its estimate of Steam Production Expense by utilizing historical averages of various recorded years (as appropriate) on an account-by-account basis. According to Edison, both recorded and future years' data were adjusted to account for significant activities that were considered non-routine and for which expenses would not be accurately estimated by either the averaging or trending method.

Staff adjusted Edison's Steam Production Expense estimate by removing the expense items for RD&D, property damage, rents, leases, and ad valorem taxes and depreciation on the fuel oil pipeline (all of which staff estimated separately). Staff then adjusted the remaining Steam Production Expense, by account, by the ratio of 1983 recorded expense to 1983 estimated expense. These adjustments equate to a recommended 10.7% reduction amounting to $16.8 million.

Staff's basic assumption in using the adjustment factor approach is that whatever caused Edison's 1983 recorded steam production expenses to be lower than what was estimated by Edison for 1983, will affect 1985 Edison-estimated expenses in the same manner. Since Edison estimated 1983 and 1985 expenses in this rate case using the same methodology, staff maintains this assumption is entirely reasonable.

Regarding differences in actual operations for test year 1985 as compared to recorded 1983, staff argues that while recorded 1983 values may have had some abnormal activity, Edison's estimating methodology accounts for this by the use of various adjustments.

According to the staff witness, possible explanations for the difference between 1983 recorded and Edison's estimates for 1983, are:

"a. The portion of expenses which are averaged or trended may include historic expenses such as those which the utility regards as abnormal and non-recurring and which the utility budgets separately for in the test year. Unless all similar historic expenses are removed from the portion of expenses averaged or trended, the utility would be estimating the same item twice; once in the trended or averaged category and once in the budgeted abnormal, non-recurring category.

"b. The assumptions made by the utility regarding its operations may have changed. For example, in the steam production category, the utility has assumed for normal O&M expenses that averages of historic years are appropriate in estimating like expenses for the years 1983 through 1986. It is possible that in 1983 there was less of a load imposed on its steam plants than was anticipated. This could be because of an above normal purchased power year or the addition of SONGS Unit 2.

"c. Items budgeted separately for 1983 as abnormal or non-recurring expenses may not have been performed in 1983."

Staff argues that it is impossible to know the reasons for Edison's inability to estimate 1983 expenses more accurately in this current rate case proceeding. As far as staff is concerned, the validity of Edison's methodology has never been proven. According to staff, at this time, 1983 recorded data is the best available measure of the accuracy of Edison's estimating methodology.

According to staff, the following table shows that, Edison's oil and gas operating mode is undergoing a significant change. Staff notes that the shift is not surprising, given the addition of the SONGS units to Edison's system and the increased availability of and reliance upon off-system purchases. Staff further notes that the energy estimated to be produced by Edison's oil and gas generation in 1985 (based on staff forecasts contained in Exhibit 52) is only about 40% of the peak oil/gas production during the drought year of 1977.

Oil and Gas Generation (Billion kWh)

Years	Total Energy
1976	43
1977	53
1978	45
1979	50
1980	44
1981	43
1982	34
1983	31
1985	22 (est.)

Staff further argues that while it does not maintain that there is a direct linear relationship between plant usage and all O&M expenses, staff believes that (reduced) usage will effect expenses to some degree. Staff contends that averaging historic expenses where oil/gas plant usage has been declining and is expected to decline further may not be appropriate. While neither staff nor Edison can quantify the dollar effect of the reduced use of the oil and gas plants, staff believes its adjustment factor does correct in 1985 for overall differences between 1983 estimated and 1983 recorded. Moreover, staff submits that since oil and gas plant usage in 1985 is estimated to be significantly less than 1983 recorded, any adjustment related to plant usage may be construed as being extremely conservative.

Edison argues that staff's basic assumption implies that 1983 can be considered typical, and is appropriate as a reference year for making future years' steam production expense estimates. In essence, according to Edison, this amounts to staff using only one year to estimate the future.

In assuming that the occurrences and situations present in 1983 will also be present in exactly the same manner in 1985, Edison argues that staff has not given sufficient consideration to the circumstances which impacted steam production expense in 1983 and which caused 1983 to be atypical.

Edison notes that the period 1981-1982 witnessed a drastic reduction in expenditures to levels comparable to the 1976 level of expenditures. This reduction was the result of a determined action by Edison's management to contain expenses within the level adopted in the 1981 test year general rate case, an amount considered by Edison management to be inadequate to properly operate and maintain the system.

Edison further notes that economic conditions present in 1983 allowed Edison to seize upon short-term cost containment opportunities that are not expected to be available in 1985 through 1987. For example, Edison's witness testified that, as a method of containing contract labor costs, Edison was able to initiate the use of temporary employees (up to the journeyman level) to supplement its work force. This compares to the traditional method of going through a service contractor or using additional full-time employees. However, Edison's witness testified that the long-term availability of these part-time workers is uncertain since many of these workers will be able to obtain full-time employment, thus reducing the ready pool of qualified personnel which has been available over the past two years. Accordingly, Edison contends that the short term cost containment opportunities available in 1983 will not be available during the test year.

Edison emphasizes that long-term cost containment is implicit in Edison's expense estimates for the test year. According to Edison, refinements in the development of work scope and detail in bid specifications has allowed Edison to request firm price bids for a greater portion of the work that is done. Also, more definitive original bid specifications have reduced the number of costly addendums to original bid awards. Edison states that the company has also introduced innovation in the use of the competitive bidding process with respect to emergency services. Emergency services requiring contractor assistance historically have been directed without competitive bids, often with a premium added for emergency response. Prospective contractors are now required to offer competitive rates for both planned and emergency work.

Edison notes that implicit in its estimate of steam production expense is the displacement of contractor services by expanded Edison sources. For example, Edison has established its own machine shop which has the capability of performing work on large equipment such as turbine rotors. This capability was previously limited to outside machine shops, which might charge premium fees in order to meet Edison's time schedules for return service. According to Edison, since Edison can now perform much of its own machine shop requirements, the outside shops have responded with more competitive rates for that portion of work still referred to outside shops.

Finally, according to Edison the company's maintenance planning organization, using a computer assisted maintenance management system, has been successful in increasing effectiveness of its maintenance forces. According to Edison's steam production expense witness the company has one of the most sophisticated overhaul maintenance management systems of any utility

in the country. Through that system Edison has been able to reduce the cost of an overhaul by reducing the number of person-days that it takes to accomplish a given amount of work. However, according to Edison these long-term cost containment measures are not expected to have as great an impact in 1985 through 1987 as they did in 1983.

Edison submits that the above cost savings resulting from innovations in the competitive bidding process are reflected in its forecasts for 1985 through the judgment exercised by the steam production personnel analyzing each individual steam production account. Edison argues that to reduce the 1985 forecast as recommended by staff would amount to a "double counting" of Edison's efforts to control costs.

Turning to Edison's other major argument, Edison contends that staff did not recognize the impact of changed operating conditions on O&M expense in assuming that 1983 was a year of operating conditions which will be repeated in 1985. Edison points out that 1983 nuclear production reached a four-year high, and that coal, hydro, and purchased power levels reached all time highs in that year, as well. According to Edison, it is unreasonable to assume that the same combination of conditions that occurred in 1983 will occur in 1985.

Moreover, Edison contends that staff has not taken into account several very significant events which will affect system operation throughout the 1985-1987 period, and which in particular will change the way Edison has traditionally operated its oil/gas units. According to Edison, this change in operation may result in a short-term interruption and reduction in some operating expenses; however, inevitable thermal and mechanical stress caused by more frequent unit startups and shutdowns, frequent major load cycles from minimum to maximum load, and difficult minimum load operations, present new concerns for future maintenance.

Edison argues that these concerns are increased when one considers the availability of nuclear generation from San Onofre Units 2 and 3 now available and the addition of Palo Verde Units 1, 2, and 3 in 1985, 1986, and 1987. Edison emphasizes that although the additional nuclear capacity will enable it to shut down more oil/gas units, the remaining oil/gas units will experience far heavier duty in terms of thermal cycling and attendant mechanical stresses. Edison points out that due to continually changing system requirements, different oil/gas units must periodically be removed from service and replaced by other oil/gas units previously off-line. This alternating of on-line units is needed to allow for planned and unscheduled maintenance, changes in minimum loads and economy energy availability, local voltage support, transmission contingencies and line loadings. Thus, on-going rotation of active units subjects nearly all the units to start-up, shut-down, and cycling stresses. Edison's witness testified that these operating requirements will entail higher O&M expenses.

According to Edison's witness, oil/gas units are used to meet the swings in load which occur between the low-load early morning hours and the peak-load afternoon or early-evening hours. The addition of large amounts of baseload nuclear capacity allows the displacement of some oil/gas capacity. Thus, a reduced number of operating oil/gas units must meet the low-load to peak-load swing and will thus be necessarily subject to greater rates of change of generating levels. In addition, Edison contends that with fewer oil/gas units on-line, forced outages will increase the severity of oil/gas load swings. In both cases there will be resultant increases in equipment stresses, and higher O&M costs. This impact comes at a time when the availability of large amounts of purchased power has tended to aggravate rather than alleviate the cycling requirements of the oil/gas units.

Edison cited specific examples of O&M expenses that are expected to increase as cycling duty increases; water and chemical requirements will be larger; there will be more corrosion of air preheater surfaces; more wear and tear on valves, motors and pumps; and insulation will deteriorate more rapidly.

In summary, it is Edison's contention that operation of the system under minimum load conditions will have a profound impact on the differences in O&M expenses between 1983 and 1985.

On the other hand, we believe staff certainly has a strong argument concerning the disparity between Edison's estimates for 1983 steam production expense and actual recorded 1983 expenses.

After reviewing the extensive testimony presented by both Edison and staff, we generally agree with staff that Edison's estimates for steam production expense are on the high side. At the same time we recognize the new operating conditions and as we did in the last general rate case, that Edison's oil/gas units are on the average 20 years old and naturally require more maintenance to maintain the same level of efficiency and reliability. In addition units that are off-line will still have to be maintained in order to meet unforeseen contingencies such as forced outages on larger units or lower than expected hydro or purchased power availability. Therefore we agree that it is reasonable to expect some overall increase in O&M expenses for the fewer oil/gas units operating during the 1985 through 1987 period. Moreover, keeping in mind that these oil/gas units are designed for baseload operation, it is to be expected that operation in a cycling mode over an extended period will result in increased wear and tear with consequent increased maintenance expense. On the other hand, we have no indication as to how soon the cycling mode of operation will be reflected in increased O&M costs.

We commend staff for its analysis of Edison's Steam Production Expenses but conclude that the $16.8 million or 10.7% downward adjustment recommended by staff is excessive. At the same time, we conclude that Edison should be able to provide reliable service with a lesser expenditure. The Administrative Law Judge recommended that we reduce Edison's request by 5%. We will reduce this recommendation by an additional $5 million. On this basis the adopted level of expenditure for the items covered by staff's steam adjustment factor is $144,850,000.

Returning to the subject of underspent (or overestimated) 1983 steam production expenses adopted in the last general rate case, we note that Edison provided a reconciliation of its 1983 recorded O&M expenses with the adopted expenditure levels included in rates (Exhibit 29). Edison's exhibit shows that for Hydro, Nuclear, and Other Production Expense, Customer Accounts and A&G expense, in the aggregate, Edison spent more than was estimated in rates. Overspending in these accounts offset the underspending for Steam Production Expense, so that, total recorded expenses amounted to $856.6 million while the amount adopted in rates was $844.1 million. Staff points out that included in the 1983 expenditures is an amount of some $19.8 million for deferred maintenance. Since staff has highlighted the fact that Edison seriously underspent the amount allowed in rates for 1983 Steam Production Expenses, we mention the above in case there is concern that Edison's shareholders benefited as a result of the under-expenditure on the 1983 steam production expenses.

b. Rents

The difference between Edison and staff is $4,000. This item includes rents for rights-of-way and land used for steam power plant operations. Staff applied its adjustment factor approach to this account. Edison argues that there is no reason why a contractually-determined expense should be adjusted by such a factor. We agree with Edison.

c. Fuel Oil Pipeline

The difference between Edison and staff is $303,000.

Edison based its estimate of depreciation expense for the fuel oil pipeline system on its plant in service estimate. Edison estimated test year 1985 depreciation expense on the fuel oil pipeline to be $4,815,000. Staff estimate was $4,512,000. The difference between Edison and staff is due to different estimates of book depreciation accrual rates as described in the section on Depreciation Expense. Although Edison takes exception to staff's estimate of book depreciation accrual rates, it is willing to accept staff's estimate with respect to the fuel oil pipeline.

We will reflect the staff estimate on the adopted results.

d. Redondo Beach Units 1-4

Edison included $243,000 in its steam production expense estimate for test year 1985, for the repair of boiler insulation at Redondo Beach Units 1-4. Staff excluded these expenses on the basis that the repairs to units 1-4 were included in Edison's 1983 general rate case. Arguing that the money for this activity (i.e., repair of units 1-4) was not spent in 1983, staff states that to include it again in test year 1985 funding would give the company money for the same expense twice.

According to Edison, the workpapers establish that funding requested in the 1983 test year general rate case was for boiler insulation repair for Redondo Beach Unit No. 6, not Unit Nos. 1-4. Also, Edison states that in response to a specific data request, staff was advised that repairs to boiler insulation of Unit No. 6 were postponed because insulation deterioration did not require immediate replacement and that Edison intends to perform the boiler insulation repair for Redondo Beach Unit No. 6 during a subsequent overhaul.

We expect insulation repairs to units 1-4 and Unit 6 to be completed by the time of Edison's next general rate case. On this basis, we will adopt Edison's estimate which covers Unit Nos. 1-4.

e. Coal Inventory Write-offs

Staff has included $34,000 in Account 501, Non-ECAC Fuel-related Expense, for both the test year and the attrition years to cover two coal inventory write-offs at the Mohave Generating Station. Edison requested recovery of this expense in its current ECAC proceeding, with respect to dump pond coal that had been contaminated. Staff proposes that this expense, which it considers reasonable, be recovered in the general rate case, rather than in the ECAC proceeding.

We will adopt the staff recommendation.

f. Fuel Storage Tank Lease

Edison leases land and forty fuel storage tanks from Texaco. Edison originally requested authorization of $10,080,000 for test year 1985 for this expense item.

Subsequently Edison negotiated with Texaco to lease only 20 tanks for 1985. Staff recommended that the actual negotiated expense amount for this item, $3,068,000 be included in test year expenses.

We will reflect this amount in the adopted results.

g. Property Damage Expense

Staff estimated property damage expense by averaging 1976-1983 recorded expenses, thus arriving at an estimate of $5,185,000 for test year 1985. Edison accepts staff's estimate for property damage expense. We will reflect the staff estimate in the adopted results. However, in future rate case proceedings we expect the number of years used to develop an average for this account to be standardized. We see no reason to litigate this account in every rate case.

h. Research, Development and Demonstration Expense

A complete discussion of RD&D expense is included in the section entitled Research, Development And Demonstration Programs.

3. Hydraulic Production Expense

Edison's estimate, the staff's recommendation and the adopted level of expenditure are set forth below.

Hydraulic Production Expense
(Thousands of 1982 Dollars)
System Expense

Issue	Edison Estimated	Staff Estimated	Adopted
Estimating Methodology:			
7-Year Average vs. 3-Year Average for Accts. 535, 538, 541 and 545 (Labor)	3,645	3,362	3,645
Adjustments:			
Shaver Dam Repairs	193	0	0
Rents	173	163	163
Property Damage	753	753	753
Research, Development and Demonstration	50	42	42
Uncontested	8,661	8,661	8,661
	13,475	12,981	13,264

a. Estimating Methodology

Edison used a seven-year (1976-1982) average to estimate 1985 labor expenses for Accounts 535, Operation, Supervision and Engineering; 538, Electric Expenses; 541, Maintenance Supervision and Engineering; and 545, Maintenance of Miscellaneous Hydro Plant. Staff based its estimate of labor expense for these accounts on a three-year (1980-1982) average. Use of different historical averages by Edison and staff results in a difference of $283,000.

The controversy relates to the amount of labor charged out to capitalized projects. Although the hydro work force has remained essentially constant since 1976, hydro power production expenses have varied, on a constant dollar basis, because of these labor amounts charged elsewhere. Edison states that for 1976 through 1979, the average amount charged to Non-O&M expenditure by the hydro work force was 7% of total payroll dollar; however, the amount was 10% in 1980 and 1981 and 18% in 1982. For 1983, the amount charged elsewhere went back down to 8%.

Staff argues that by using a three-year average rather than seven years of data, most of the gains in productivity shown by a declining trend line from 1976 to 1982 will still be reflected in its 1985 estimates. According to staff, if the decline in expenses is for reasons other than productivity the use of three years' data will normalize the estimate.

We conclude that the three years used by staff (1980-1982) are not representative since those years reflect the highest charges to capitalized Non-O&M expense accounts. Accordingly, we will adopt Edison's estimates for Accounts 535,538, 541, and 545 (Labor) since Edison's figures reflect a more typical allocation of labor to capitalized projects.

b. Adjustments

(1) Shaver Dam Repairs

Edison requested $193,000 for remedial repairs at Shaver Dam. Staff has excluded the full amount, stating that if, after a pending review by an independent board of consultants to assess the dam's structural integrity it is determined that major repairs are required, the repairs will probably be made during the period of the next general rate case. Edison agrees with staff's adjustment of this expense. We will adopt the staff adjustment.

(2) Hydro Production Rents

Edison estimated rent expense for test year 1985 to be $173,000, by averaging rents for the period 1976 through 1982 in 1982 constant dollars. Staff, on the other hand, included 1983 data by averaging 1976 through 1983 rents in 1982 constant dollars.

We agree that since these particular rents cannot be estimated on the basis of the contracts, it is reasonable to use an averaging approach. However, we see no reason for argument in each rate case over the number of years used to obtain the average. We note staff used an average of 8 years in this account and 7 years in the account which we will discuss next. It could be argued that staff selects the number of years which yields the lowest estimate. This is not fair and staff should adopt a consistent approach. However since Edison stipulated to the staff estimate, we will adopt the staff estimate for purposes of this proceeding.

(3) Property Damage Expenses

Edison estimated property damage expense to be $708,000 for test year 1985. Staff estimated this expense item to be $753,000, by averaging 1976 through 1983 recorded expenses in 1982 dollars. Edison agrees with staff's estimate of this expense item.

We note staff used a 7-year average of the most recent recorded data. This is another account where a consistent number of years should be used for the reasons discussed above. Edison and staff, in this instance, both used 7 years of recorded data but staff had 1983 data which was not available to Edison. We will adopt the staff estimate since it includes the latest recorded information.

(4) Research, Development and Demonstration Expense

A complete discussion of RD&D expense is included in the section entitled Research, Development, and Demonstration Programs, below. The difference between Edison and staff in RD&D expense for Hydraulic Production activities is $8,000 in 1982 dollars.

4. Other Production Expense

Edison's estimate of Other Production Expense exceeds staff's estimate by $609,000 in 1982 dollars. The table below provides details of the differences.

Other Production Expense
(Thousands of 1982 Dollars)
System Expense

Issue	Edison Estimated	Staff Estimated	Adopted
Estimating Methodology:			
Averaging Methodology	7,910	7,583	7,684
Adjustments:			
Property Damage	1,910	1,109	1,109
Research, Development and Demonstration	4,755	4,505	4,505
Uncontested	9,607	9,607	9,607
Escalation:			
Historical Escalation			
Nonlabor	0	(32)	0
	23,381	22,772	22,905

a. Estimating Methodology

Edison used a combination of averages and trends to estimate 1985 expenses (labor and non-labor) for Account 546, Operation Supervision and Engineering; Account 549, Miscellaneous Other Power Expense; Account 552, Maintenance of Structures; and Account 554, Maintenance of Miscellaneous Other Power Plant. Staff based its estimate of expenses for these accounts on an average of 1981 and 1982 recorded data, resulting in the following recommended adjustments, by account:

Differences Between Edison and Staff
Other Production Expense
(Thousands of 1982 Dollars)

Account	Labor	NonLabor	System Total	Adopted
546, Oper. Super. & Engrg.	26	26	52	26
549, Misc. Other Power Expenses	45	156	201	156
552, Maintenance of Structures	7	(9)	(2)	(9)
554, Maint. of Misc. Other Power Plant	23	53	76	53
Difference Due to Averaging Trending Methodology	101	226	327	226

The above difference of $327,000 relates to an Edison estimate of $7.9 million and a staff estimate of $7.6 million for these accounts.

Edison argues that the activities and related expenses in the above accounts are fixed or routine in nature and/or would tend to be incurred at a generating station regardless if a unit or units at that station were on-line and in normal operation.

The controversy hinges on the effect on recorded expenditures due to placing in operation certain new combined cycle plants as follows:

Long Beach Unit 8	12/31/76
Cool Water Unit 3	3/31/78
Cool Water Unit 4	8/31/78
Long Beach Unit 9	4/30/79

The largest area of difference with regard to this issue is in Account 549 (non-labor). Materials and expenses included in this category are those which staff believes are associated with the start-up of a new generating facility rather than normal reecurring expenses. Staff notes that the recorded averaged portion of these expenses used by Edison in establishing this account in constant 1982 dollars are as follows:

1979	$844,000
1980	466,000
1981	346,000
1982	337,000

We agree with Edison's argument related to the labor portion of these expenses. However, the above recorded data for the nonlabor portion shows that 1979 and 1980 are unusual years and there is a declining trend to these expenses which supports staff's argument. Accordingly, we will adopt the staff estimate for nonlabor expenses.

b. Adjustments

(1) Property Damage Expense

Edison estimated property damage expense on a budgetary basis, arriving at an estimate of $680,000. Staff incorporated 1983 data into an average of 1976-1983 historic expenses, resulting in an estimate of property damage expense of $1,109,000. Edison agrees with staff's estimate of property damage expense.

While we agree with the use of an average for estimating this account, we note staff used 8 years of recorded data. Seven years of data was used in Edison's last general rate case. As we pointed out previously, for this type of account, there is no reason to change for every rate case the number of years used to calculate the average. For purposes of this proceeding, we will adopt the staff estimate.

(2) - Research, Development And Demonstration Expense

The difference in RD&D expense for other production is $250,000 in 1982 dollars. It relates to the Wind Energy Conversion Program. This issue is discussed in the section entitled Research, Develoment and Demonstration Programs.

5. Transmission Expense

Edison's estimate of Transmission Expense exceeds staff's estimate by approximately $4.9 million in 1982 dollars. The following table provides details of the differences between the company and staff and sets forth the adopted levels of expenditures:

Transmission Expense
(Thousands of 1982 Dollars)

	System Expense		
	Edison	Staff	
Issue	Estimate	Estimate	Adopted
Estimating Methodology			
Averaging/Trending	7,957	6,429	7,577
Adjustments			
Big Creek T/L Ground Clearance	2,859	0	2,889
Account 565 - Wheeling Charges	13,883	13,883	13,883
Research, Development, and Demonstration	712	500	500
Uncontested	37,535	37,535	37,535
Escalation			
Historical Escalation Nonlabor	0	(82)	0
Total	62,976	58,265	62,384

a. Estimating Methodology

With the exception of Account 565, Transmission by Others, Edison estimated transmission expense by adjusting 1976-1982 historical expenses to exclude unusual expenditures and the effects of accounting changes, rejecting historical labor or nonlabor expense from one or more years in those accounts where such expense was considered unrepresentative, and then applying either an averaging or trending methodology depending upon the company's judgment of future activity with respect to each account. Finally, Edison adjusted these test year estimates to reflect the initiation or cessation of specific programs and expected changes in activity levels.

Staff estimated transmission expense by using a similar combination of averages and trends. However, staff disagreed with Edison's exclusion of certain years from the estimating basis for various accounts, and also disagreed with respect to whether certain accounts should be averaged or trended.

(1) Account 562, Station Expenses

Edison averaged 1980, 1981, and 1982 historical expenses to estimate the labor component of this account for test year 1985. Staff based its estimate of the labor component on 1982 recorded expense. Although Edison disagrees with staff's methodology for estimating labor expense for this account, upon further review of the estimated labor requirements for this activity in the test year, Edison concludes that staff's estimate is acceptable.

Turning to the nonlabor component, Edison's estimate is $1,760,000 and the staff estimate is $1,536,000. Recorded 1982 is $1,747,000 and recorded 1983 on the same basis is $1,759,000.

Edison used a single year, 1982, to estimate the nonlabor component of this account. Staff inquired as to the reasons for the exclusion of all previous years from the estimating methodology for this account. In response to staff's data request, the company stated:

> "Historically, the 'other' costs to this account have varied and are generally unpredictable. A variety of expenditures are included in the account (janitorial work and supplies, station meter and instrument supplies, utility bills, meals, travel time, etc.); in general, everything that is not specifically provided for in other operating accounts. Recent malicious damage incidents (equipment damaged by gunshots at several locations) indicate that we will experience the need for greater surveillance and security expenditures in future years. The year 1982 was judged to be more representative of future needs, therefore, the years 1976 through 1981 were deleted for estimating purposes."

Staff based its estimate of nonlabor expense for this account upon an average of 1976-1982 expense. Staff concludes that the existence of several incidents of malicious damage occurring in 1982 do not indicate the "initiation of a siege of continued vandalism against SCE property."

Edison further states that in recent years the increases in Account 562 have been largely due to contract security personnel hired to increase surveillance during periods of suspected vandal activity. It is Edison's judgment that it would be prudent to secure temporary security personnel to increase surveillance from time to time on a consistent basis henceforth.

We conclude that Edison should be allowed the additional expense for contract security personnel. Also we note that both 1982 and 1983 expenses have maintained a constant level, which supports the reasonableness of Edison's estimate. Accordingly, we will adopt Edison's estimate for the nonlabor portion of Account 562.

(2) Account 570, Maintenance Of Station Equipment

The only issue with respect to this account involves the nonlabor component. Edison based its estimate of nonlabor expense on a four-year average of historical data for the period 1979-1982. Staff used a seven-year declining trend to estimate the nonlabor component of this account, relying largely upon the statistical significance of the R-Squared value of the trend. Staff also relied upon Edison's response to a staff data request, which staff considers an admission of a trend toward reduction of certain activities in this account.

Edison argues that staff did not consider the corporate budget constraints which prevailed during the years 1981 and 1982.

Edison's estimate for the nonlabor component is $4,613,000; staff's estimate is $3,685,000. 1982 recorded is $2,882,000. 1983 recorded on the same basis is $5,016,000; however, this figure adjusted for deferred maintenance on the staff basis is $4,892,000; then adjusted for 1985 growth and the SONGS stipulation is $4,943,000.

We conclude that based on 1983 recorded adjusted expenses, Edison's estimate is reasonable and should be adopted.

(3) Account 571, Maintenance Of Overhead Lines

The only issue between Edison and staff with respect to this account involves the labor component. Edison utilized an average of recorded expense for the years 1976-1982 to estimate the labor component of this account. Staff used 1982 recorded expense as their estimate of the labor component, resulting in a downward adjustment of $380,000.

Edison argues that as was the case with respect to staff's adjustment of the nonlabor component in Account 570, staff did not consider the corporate budget constraints that were in effect in 1981 and 1982. Edison contends that by utilizing 1982 recorded expense to forecast 1985 test year expense for this activity, staff, in effect, perpetuates those budget constraints. Edison submits that average-year conditions are implicit in Edison's use of averaging to estimate the labor component of this account. Edison points out that since the company included the budget-constrained years of 1981 and 1982 in its historical average, the company's test year estimate already incorporates a significant element of conservatism.

Edison's estimate for the labor component is $3,188,000; the staff's estimate is $2,808,000. 1982 recorded is $2,808,000 and 1983 recorded on the same basis is $2,485,000.

We conclude that based on 1983 recorded, the staff's estimate is reasonable and should be adopted.

b. Adjustments

(1) Big Creek Transmission Line

Edison has undertaken a program to improve the ground clearance of conductors on the Big Creek to Magunden Transmission Line, by replacing insulators on the line with new insulators of a different configuration. Edison proposes expense treatment of this activity. Staff considers this activity to constitute a "substantial addition," and recommends that it be capitalized. This recommendation results in a downward adjustment, as discussed in the section entitled Rate Base, below.

(2) Wheeling Charges

Wheeling expense includes the cost of transmission of energy by others where the rate charged is independent of the amount of energy transmitted. Edison accepts the methodology used by staff in estimating this expense, which reflects the terms of the individual contracts assumed to be in effect in 1985.

We will adopt the staff estimate.

(3) Research, Development, and Demonstration

A complete discussion of RD&D expense is included in the section entitled Research, Development, and Demonstration Programs, below. The difference in RD&D expense for Transmission is $212,000 and is related to Account 566 - Miscellaneous Transmission Expense.

6. Distribution Expense

Edison's estimate of Distribution Expense exceeds staff's estimate by approximately $10.2 million in 1982 dollars. The following table sets forth the company's estimate, the staff estimate, and the adopted levels of expenditure.

Distribution Expense
(Thousands of 1982 Dollars)

Issue	System Expense Edison Estimate	Staff Estimate	Adopted
Estimating Methodology			
Averaging/Trending	67,687	58,772	60,525
Adjustments			
Deteriorated Pole Replacement Program	2,300	1,270	2,300
Underground Inspection Program	694	694	694
Maintenance of Underground Lines - 1.5% Growth Adjustment	273	0	156
CVR Regulator Program	1,028	1,028	685
RAC/RAM Switches	139	139	139
Landscape Care	1,237	1,237	1,237
Research, Development, and Demonstration	50	0	0
Uncontested	54,918	54,918	54,918
Escalation			
Historical Escalation Nonlabor	0	113	0
Total	128,320	118,165	120,648

a. Estimating Methodology

Edison generally used a seven-year historical average (1976-1982) to estimate 1985 test year distribution expense. According to Edison, this methodology was used in order to properly reflect the severe fluctuations in recorded expense that occurred during the years 1981 and 1982. These fluctuations were influenced by an effort on the part of Edison's management to contain corporate expenditures within the level adopted in the 1981 test year general rate case. Edison contends that this resulted in distribution expense levels being significantly curtailed during 1981 and 1982. In addition, Edison notes that severe storm damage further impacted the fluctuation of 1982 recorded expense.

Edison used the seven-year historical average to estimate seven of the accounts, Accounts 582, 583, 584, 586, 592, 593, and 594, respectively. Staff generally used a trending methodology to prepare these estimates.

According to Edison, staff views the curtailment of distribution expenses that occurred during 1981 and 1982 as "productivity improvements." By utilizing recorded 1976 through 1982 expense data in their analysis, and focusing on 1982 as a base, staff obtained declining trends upon which the adjustments (with the exception of Account 598, Maintenance of Miscellaneous Distribution Plant) were based.

Edison argues that had staff considered recorded 1983 expense data in its analysis, it would have necessarily concluded that the downward trend projected from the 1981 and 1982 recorded expenses did not continue into 1983. Edison submits that consideration of 1983 recorded data demonstrates that a recovery from the two years of curtailed distribution expenditures was taking place. However, Edison notes that this recovery did not reach the level that was originally projected by the company because of severe storm damage that occurred during the first quarter of 1983, which limited the company's ability to recover to the extent anticipated.

We will first discuss the group of seven accounts mentioned previously. After reviewing the testimony, we conclude that both Edison and staff have a reasonable basis for their estimates. Therefore, as a compromise, we will use 1983 recorded labor and nonlabor expenses as the basis for making a decision on which estimate to adopt. On this basis we conclude that Edison's estimate for Account 582, should be adopted. For the same reasons we conclude that staff's estimates for Accounts 583, 584, 586, 592, 593, and 594 should be adopted.

Turning to Account 597--Maintenance of Meters, Edison used a seven-year linear trend (1976-1982) to reflect the constant rate of growth, which it contends is being experienced within that account. According to Edison, utilization of a historical average for Account 597 would have been inappropriate considering the consistency of the growth pattern.

Staff used a seven-year average to estimate this account. Staff argues that the R^2 values of Edison's estimates are .50 and .49, respectively. Staff points out that this is well below its R^2 = .60 criterion.

Based on 1983 recorded expenses, we conclude that Edison's estimate is reasonable and should be adopted.

Edison estimated expense for Account 591--Maintenance of Structures, using a two-year historical average. According to Edison, the two years of recorded expense reflected in the average are reasonably consistent, and were relied upon in lieu of attempting to adjust the prior years' recorded expense to reflect the complex accounting adjustments between Account 591 and Account 588, Miscellaneous Distribution Expenses, that took place during the years 1976-1980.

Since Edison made no accounting adjustments affecting this account after 1979, staff did include 1979 and 1980 in its estimate which is also based on an average.

Based on 1983 recorded we conclude that Edison's estimate is reasonable and should be adopted.

Turning to Account 598--Maintenance of Miscellaneous Distribution Plant, staff's estimate is approximately $2 million lower than Edison estimate, due to the use of different historical average periods in the estimation of storm damage expense. Edison used a five-year historical average (1978-1982) to estimate storm damage, whereas staff based its estimate upon a seven-year historical average.

Edison notes that a five-year historical average has been the consistently used and adopted estimating methodology for storm damage expense for at least two prior Edison general rate cases. We see no reason to change to a seven-year average. Also, there is a need to be consistent regardless of whether a five-year or seven-year average is used. Accordingly, we will be consistent and use the latest five-year average which includes 1983 recorded. On this basis the adopted expense level for the labor component is $29,000 and $14,965,000 for the nonlabor component.

For Account 580--Operation Supervision and Engineering, staff's estimate is approximately $936,000 lower than Edison's estimate. Staff's estimate of expense for Account 590--Maintenance Supervision and Engineering, is approximately $491,000 lower than Edison's estimate. These differences are due to differing estimating methodologies used by Edison and staff with respect to the two Clearing Accounts upon which the expense estimates for Accounts 580 and 590 are derived.

Clearing Accounts 184.3 and 184.4 are corporate accounts which are intended to capture overhead costs that are subsequently cleared to appropriate FERC accounts through an allocation process. Allocations from both Clearing Account 184.3 and Clearing Account 184.4 are made to both Account 580 and Account 590 based upon the direct labor that is charged into Accounts 580 and 590.

Edison estimated the level of expense in Clearing Account 184.3 by using a seven-year (1976-1982) historical average. Staff estimated the level of expense for Clearing Account 184.3 by using a seven-year (1976-1982) linear trend. Staff's use of the trend for this Clearing Account was based upon calculation of a high R-Squared statistic.

Edison argues that by relying exclusively upon the statistics associated with its trending methodology, staff did not take into account the distribution expense curtailments that occurred during 1981 and 1982. Edison contends that, as with respects to the other eight distribution accounts which staff adjusted based on use of different estimating methodologies than the company's, the declining trends found by staff resulted in part from the curtailments that occurred during 1981 and 1982. Edison submits that recorded 1983 data demonstrates that a recovery from the years of curtailed expenditures was taking place, which leads to the conclusion that reliance on a declining trend is inappropriate.

Edison based its estimate of the expense level in Clearing Account 184.4 upon a seven-year (1976-1982) linear trend. Staff based its estimate of the expense level for Clearing Account 184.4 upon a seven-year (1976-1982) historical average because it observed a low R-Squared statistic in a trending of that account.

Although Edison is cognizant of the low R-Squared in the trend for Clearing Account 184.4, it is the company's position that this statistic was caused by the curtailment of distribution expenditures during the years 1981 and 1982, as previously discussed. Edison argues that exclusion of the years 1981 and 1982 from the trend of this account would, as with other accounts adjusted by staff, demonstrate recovery in expense level, and in this account would have resulted in an extremely high R-Squared statistic. For this reason, Edison contends that use of a linear trend in estimating the expense level for Clearing Account 184.4 was reasonable.

Returning to Accounts 580 and 590 -- we conclude that it is appropriate to consider the overall reasonableness of the estimates for these accounts rather than the amounts contained in the clearing accounts. Therefore, based on 1983 recorded labor and nonlabor expenditures -- we conclude that the staff estimates for Accounts 580 and 590 are reasonable and should be adopted.

For Account 589 -- Rents, staff's estimate is approximately $22,000 lower than Edison's estimate. The company based its estimate of expense for this account upon a seven-year (1976-1982) historical average. Edison selected this methodology due to the fluctuations in timing of rental payments for real property, distribution rights of way, and overhead railroad crossings, including the renewal of leases, which result in year-to-year variations in the expenses that are charged to this account.

Staff based its estimate of expense for this account upon an average of the four most recent years (1979-1982), based upon the contention that expenses in this account are dependent upon the contracts which are in effect.

We note that 1983 recorded exceeds both Edison's and staff's estimate. We conclude that it is reasonable to use the recorded 1983 figure for the test year estimate.

b. Adjustments

(1) Deteriorated Pole Replacement Program

Edison estimated its expense for test year 1985 for the deteriorated pole replacement program to be $2,300,000. Staff's estimate of this expense for test year 1985 is $1,270,000, resulting in a recommended $1,030,000 downward adjustment.

Edison notes that the Commission authorized the implementation of the company's deteriorated pole replacement program in its decision in the 1983 test year general rate case. This original program, which commenced in 1983, assumed that all wood poles set prior to 1930 were deteriorated past repair and would be replaced over a ten-year period at a rate of 4,600 poles per year. The original program also assumed that 40% of all wood poles set between 1931 and 1940 (42,000 poles) required inspection to determine which were in need of replacement. Beginning in 1984, the 1931-1940

poles needing replacement would be replaced over a ten-year period at a rate of 1,680 poles per year. The annual expense for the original deteriorated pole replacement program was estimated to be $2,295,000.

During 1983, Edison undertook to inspect a systemwide representative sample of poles. After inspecting 11,207 poles, Edison projected the number of poles needing replacement, and the number of poles which, though decayed, could have their useful lives extended through reinforcement (stubbing) or treatment. As noted in the staff's Results of Operations Report, this information enabled Edison to propose an improved deteriorated pole replacement program with the following annual activity levels beginning in 1984 (and assuming a 15-year activity cycle): (1) inspection and treatment of 77,800 poles; (2) replacement of 3,890 poles; and (3) reinforcement of 3,633 poles. Edison estimated the annual expense associated with the improved deteriorated pole replacement program to be $2,300,000, which is reflected in Edison's estimate of test year 1985 distribution expense.

Staff has agreed that the improved deteriorated pole replacement program is an improvement over the original program, and staff further agrees with respect to the proposed activity levels and total associated costs. However, staff contends that because the replacement activities under the original program did not proceed as quickly during 1983 as originally anticipated, and because the poles which were not replaced in 1983 will be replaced under the improved program, Edison is requesting funds for activities for which funds have already been authorized. Accordingly, staff applied a reduction of $1,370,000 to Edison's expense estimates for test year 1985 and attrition year 1986. This reduction represents the difference between the funds authorized for the original program in Edison's 1983 test year general rate case

decision, and the amount actually spent during the original program. Applying the reduction evenly over test year 1985 and attrition year 1986, staff arrived at a downward adjustment to the Edison's test year 1985 expense estimate of $685,000.

Edison argues that the implication of staff's recommendation is that, had Edison proceeded with a program that has been acknowledged to be less effective than the improved program, Edison would not be faced with a downward adjustment for this expense item. According to Edison, such an adjustment would penalize the company for attempting to develop a more reasonable and prudent pole replacement program and therefore should be rejected.

The remainder of staff's downward adjustment for deteriorated pole replacement expense in test year 1985 is approximately $340,000. Staff recommends this downward adjustment because Edison added the total annual expense of its proposed improved deteriorated pole replacement program to its base estimate for this account developed from a seven-year historical average and the company did not make a compensating adjustment to historical expense to account for pole replacements accomplished during the historical period. Staff recommends this downward adjustment in order to avoid what it considers double counting of incidental pole replacement expense.

Edison agrees that it did not adjust its recorded expense average to reflect incidental pole replacements. According to Edison, incidental pole replacements have and will continue to be made outside of the formal deteriorated pole replacement program, as a result of normal rebuilding activity, street widening, and replacements resulting from storms and vehicular damage. Therefore, Edison contends that the company's estimate of expense for deteriorated pole replacement program does not double-

count pole replacement expense. Moreover, according to Edison the incidental pole replacements are considered routine rather than unusual events for which recorded data used in an average should not be adjusted.

In summary, we should note that the issue in this instance is not deferred maintenance; rather, it is whether the utility should have the flexibility to shift earmarked funds if it is in the ratepayers' interest to do so. We conclude that if the utility has a valid reason based on economic or other considerations, then it should have the flexibility. This is simply prudent management.

Accordingly, we will adopt Edison's estimate for the pole replacement program.

(2) Underground Vault Inspection

Edison and staff are in agreement with respect to the recommended level of expense for this activity, which is estimated for test year 1985 to be $694,000.

(3) Maintenance of Underground Lines

Edison included a growth adjustment of 1.5% to its estimate of expense for maintenance of underground lines, based on the increased level of underground inspections that are being performed in conjunction with the company's five-year program to inspect all of its underground facilities.

Edison argues that because of the increase in the level of underground inspections being performed, it is reasonable to expect that there will also be a certain amount of increase in the maintenance expense associated with these inspections. Moreover, according to Edison it is also reasonable to assume that there will continue to be an increase in underground line maintenance due to growth of the underground distribution system. Accordingly, the company adjusted its estimate of expense for maintenance of underground lines by 1.5%, which resulted in an increase in the estimate of $273,000.

Staff does not accept the company's adjustment, on the basis that historical expense data for this account do not display a significant corresponding increasing trend.

Edison argues that staff has agreed that there have been and will be increases in the number of customers and the miles of underground line in the company's distribution system from 1982 to 1985. Moreover, staff agreed that increases in the number of customers and miles of underground line will result in increased underground line maintenance expenses. Edison contends that considering the curtailment in distribution expense during 1981 and 1982 which has been previously discussed, reference only to the historical expense data for this account would not display an increasing trend.

Based on 1983 recorded we conclude that a 1% growth rate is reasonable. Accordingly, we will adopt the staff estimate adjusted for a 1% growth rate.

(4) CVR Regulatory Program

Edison and staff are in agreement with respect to the level of test year 1985 expense for this activity, which is estimated to be $1,028,000 per year for two years. We will spread this adjustment over three years since Edison's rate case cycle has been extended to three yers.

(5) RAC/RAM Switches

Edison and staff are in agreement with respect to the recommended level of expense for this activity, which is estimated for test year 1985 to be $139,000. We will adopt this amount.

(6) Landscape Care

Edison's estimate of 1985 test year expense for Account 588 (Miscellaneous Expenses) includes an estimate of landscape care expense of $1,231,000. Staff accepted the company's estimate of landscape care expense. We will adopt Edison's estimate.

(7) Research, Development, and Demonstration Expense

A discussion of research, development, and demonstration expense is included in the section entitled Research, Development, and Demonstration Programs.

- 89 -

7. Customer Accounts Expense

The following table sets forth Edison's estmate, staff's estimate and the adopted level of expenditure for the test year. The difference between Edison's estimate and staff's estimate is $511,000 excluding uncollectible expenses.

Customer Accounts Expense
(Thousands of 1982 Dollars)
System Expense

Issue	Edison Estimated	Staff Estimated	Adopted
Estimating Methodology			
Account 902, Meter Reading Expense	988	477	477
Account 905, Misc. Customer Accounts Expenses	2,530	2,530	2,530
Adjustments			
Customer Service Representatives	3,049	3,049	3,049
Customer Accounting System	939	939	939
Postage	8,278	8,278	8,733
Uncontested	53,819	53,819	53,819
Total (Excluding Uncollectibles)	69,603	69,092	69,547

a. Estimating Methodology

(1) Account 902 Meter Reading Expense

The difference between Edison and staff relates to the number of additional meter readers needed in the test year.

Edison used 1982 recorded expense, adjusted to reflect an anticipated 2 percent increase in customers, to estimate meter reading expense in test year 1985. Staff based its estimate on 1983 recorded expense, adjusted to reflect staff's 1985 forecast of customers. Staff's methodology resulted in a recommended $511,000 downward adjustment in this account.

Edison notes that as determined by staff, the historical average increase in the percentage of customers during the period 1978-1982 was 2.34 percent. Edison argues that its estimate of meter reading expense is conservative, when considered in light of the historical trends in customer growth.

While Edison's estimating methodology appears reasonable, the end result is not reasonable in light of 1983 recorded expense. Based on 1983 recorded expense, which is below 1982 recorded, we conclude that the staff estimate for total meter reading expense is reasonable. The staff recommended adjustment should be adopted.

(2) Account 905, Miscellaneous Customer Accounts Expenses

Edison used a two year (1981-1982) average to estimate expense for this account for test year 1985. Staff used a three year average by including 1983 recorded expense in arriving at its estimate. The difference between Edison and staff due to the use of different averaging periods is $4,000.

Although Edison does not concur with staff's use of a different averaging period, after further review, and considering the nominal amount remaining at issue in this account, Edison accepts staff's estimate of Miscellaneous Customer Accounts expense for test year 1985.

We will adopt the staff estimate.

b. Adjustments

(1) Customer Service Representatives

Staff estimated the total level of expense for test year 1985 for Edison's Customer Service Representative training program to be $3,049,000. Edison accepted staff's estimate of expense for this item.

We will adopt staff's estimate.

(2) Customer Accounting System

Staff estimated the total level of expense for test year 1985 for Edison's Customer Accounting System to be $939,000. Edison accepted staff's estimate of expense for this item.

We will adopt staff's estimate.

(3) Postage

Edison states that it has historically considered postage expense to be a nonlabor expense item, subject to applicable nonlabor escalation rates. According to Edison, this approach eliminated the necessity of adjusting the estimate for customer growth or increases in postage expense. Based on Edison's nonlabor escalation estimate for the test year 1985, test year postage expense was estimated to reflect an approximate increase of 2 cents.

Staff maintains its traditional position, recommending that no increase in postage should be included in test year 1985 expense unless an increase in postage rates is definitely known. Accordingly, staff has removed postage expense from nonlabor expense in Account 903--Customer Records and Collection Expense, and included that expense in another category, which is not subject to escalation. However, staff did consider an additional increase in postage expense to reflect customer growth. Moreover, staff recommended that postage expense be adjusted in attrition year 1986 if an increase in postage rates in 1985 actually takes place.

Edison and staff agree, that should a postage increase occur prior to a decision being rendered in this case, that increase should be reflected in the adopted level of postage expense. Since it is now clear that a postage increase will go into effect on February 17, 1985, we will increase our adopted postage expense by $454,780. This represents the prorated amount of an estimated annual $521,996 increase.

The staff calculation of postage expense is set forth in Exhibit 67. We will adopt the staff recommendtion. Also, we will adjust postage expense during the attrition years if an increase takes place in the prior year and it is not reflected in rates.

(4) Account 904. Uncollectible Accounts

Edison and staff base their estimates of uncollectible expense on an uncollectible factor of 0.226 percent. The difference between Edison and staff's estimates of uncollectibles expense is a direct function of their different estimates of present rate revenues.

We will use the same factor in calculating uncollectible expense for the adopted results of operations.

c. Additional Customer Accounts Issues

(1) Joint Meter Reading, Billing and Collection

Edward Duncan, an Intervenor in this proceeding inquired regarding joint meter reading, billing and collection. Edison stated its position with respect to this matter in a letter to the ALJ dated June 22, 1984.

In July, 1980, Edison, in conjunction with Southern California Gas Company (SoCal Gas) contracted with the firm of Ernst and Whinney to undertake a preliminary determination of the feasibility of joint meter reading by Edison and SoCal in their overlapping service territories. This preliminary feasibility study

was conducted because of staff's belief that meter reading conditions of the two companies were similar enough that joint meter reading might be feasible and could result in significant meter reading economies for both companies. The study was completed in February, 1981.

-93a-

Edison states that the company has carefully reviewed and validated the findings of the report, which conclude: (1) that joint meter reading is not financially viable during the five year to ten-year planning horizon, and (2) that conversion to joint meter reading should not be undertaken at this time. In view of these conclusions, Edison does not intend to undertake any new studies beyond the preliminary feasibility study at this time.

Edison agrees that an ongoing consideration is the rapid advancement being made in metering technology including on-site billing and/or remote system interrogration. Edison states that it has and will continue to evaluate these technologies to the degree they may be cost beneficial.

Staff argues that while the recommendation of the feasibility study conducted in 1980 was negative, staff's review of the report indicates that a savings of between $10 million and $12 million (presumably in 1980 dollars) could be realized over 10 years. According to staff, Edison's assertion that the project is not financially viable during the five-year to ten-year planning horizon misstates the conclusion of the consultant's report which indicated that "joint meter reading is not financially viable during the earlier years of a 5 to 10 year planning horizon" (emphasis added). Staff believes that some pilot program in a limited geographical location in the Edison/SoCal Gas service territory could well prove to be beneficial for the ratepayers of both utilities. Staff recommends that $100,000 be included in rates to finance the development and analysis of any such pilot program.

We agree with staff that a pilot joint meter reading program should be instituted; however, the dollar amount suggested by staff is inadequate to implement a meaningful program. Accordingly, we will allow Edison to accrue expenses of up to $500,000 over three years in an interest bearing memorandum account. This pilot program will conclude at year end 1987. We expect Edison and

SoCal Gas to work together and keep staff informed. The utilities will submit a joint progress report annually and the first report will be due on July 1, 1986. Edison may seek to recover all reasonably incurred costs for this program, in its next general rate case.

We further note that the subject of advancements in meter reading technology was an issue in PG&E's last general rate case proceeding. Since many of the regulated California utilities are considering substantial capital investments in this area, we expect staff to take an active role. Also, we expect the utilities to share their expertise with each other. Here again we urge staff and the utilities to conduct joint workshops so that there is a full exchange of information.

We expect a report to be provided in Edison's next general rate case proceeding.

(2) Inter-Utility Credit Follow-Up System

Edward Duncan also inquired regarding credit follow-up on delinquent customers. Edison also responded to this inquiry in its June 22, 1984 letter.

Edison states that the company has been working with an outside firm as well as other gas and electric utilities within the state to develop an inter-utility credit follow-up system. A prerequisite to the establishment of such a system, however, is the accumulation of certain standardized credit data. According to Edison, the credit scoring system which the Commission recently authorized for implementation by the company in Resolution E-2005 issued June 6 1984 is the first step towards the accomplishment of this goal.

Edison further states that it is anticipated that a system for interchanging credit data as well as for credit follow-up will be operational during test year 1985.

We expect a report on this system in Edison's next general rate case proceeding.

8. Customer Service And Informational Expense

These expenses are discussed under Conservation and Load Management Programs.

9. Administrative and General Expense

Edison's estimate of Administrative and General (A&G) Expense excluding franchise fees exceeds Staff's estimate by approximately $14.3 million. Edison's estimate, the Staff's estimate, and the adopted expense levels are set forth in the table below.

Administrative and General Expense
(Thousands of 1982 Dollars)
System Expense

Issue	Edison Estimate	Staff Estimate	Adopted
Estimating Methodology			
Budgetary Adjustment	1,726	448	462
Historical (1978-1982) Total A&G Employee Growth Factor	15,611	13,219	13,219
KWh Sales and Customer Growth Factors	16,462	15,812	15,812
Differences between 1983 Recorded and 1983 Estimated	14,387	12,515	12,515
Use of 1983 Recorded for 1985 Estimate	5,565	4,628	4,992
Subtotal	53,751	46,622	47,004
Adjustments			
Westinghouse Litigation Costs	1,501	1,501	1,501
SONGS Unit 1 Personnel	117	117	117
A&G Charged to Others SONGS Unit 1	0	0	0
F/MBE Expense	335	0	168
RD&D	18,411	17,813	17,913
Pensions & Ben.	103,162	96,916	96,610
Rounding	0	2	2
Uncontested	86,938	86,938	86,938
Total Exc. Franch.	264,215	249,909	250,249

Referring to the previous table, we will first discuss EEI dues and then set forth the arguments based on estimating methodologies. Our disposition of issues on estimating methodology is contained in the section entitled Summary and Discussion, below. Lastly, we will address the adjustments.

a. EEI Dues

Staff excluded 25% of Edison's estimated Edison Electric Institute (EEI) dues, based on the decision in PG&E's 1984 test year general rate case. Edison's estimate for 1985 is $455,000 and staff's recommendation is $341,000. EEI dues are included in Account 930.2.

Edison notes that the Commission did not allow expenses for dues paid to EEI in Edison and PG&E's last general rate cases because of an absence of a convincing showing that direct benefits from this expense accrued to ratepayers. In PG&E's 1984 test year general rate case, the Commission concluded that the record demonstrated that benefits accrued to the ratepayer through PG&E membership of EEI, and allowed EEI dues as a ratemaking expense after a 25% reduction for lobbying activities which the Commission found it did not benefit the ratepayer. In Edison's present case, the Company introduced evidence of the immediate and long-term benefits resulting from Edison's participation in EEI activities. The Company identified $3,031,000 in estimated benefits accruing to ratepayers, which is far in excess of the amount budgeted by Edison for the 1985 dues expense. No party to this proceeding has taken issue with Edison's estimate of EEI expense, or the reasonableness of those expenses, with the exception of Staff's reduction of 25% for lobbying activities.

Edison argues that Staff's sole basis for the 25% reduction is its reliance upon a reduction adopted by the Commission in PG&E's last general rate case. Edison states that the Company has not included in its request funding for EEI dues associated with EEI's media communication program or for direct lobbying.

In Edison's last general rate case, the Commission stated that "The burden is on Edison to show that the contributions for which it seeks ratepayer support provide (specific benefits to ratepayers)." Edison argues that it has met this burden in the present case with clear record evidence of the benefits accruing to Edison's ratepayers from Edison's membership in EEI. Edison notes that the only record evidence respecting lobbying activities is that based on the federal definition of lobbying reporting requirements. Only 2% of EEI's activities constitute lobbying and that Edison has not requested EEI funding relative to those lobbying activities. Therefore, Edison argues its request of $407,000 should not be reduced by the Staff-proposed 25% factor.

We conclude that the federal definition of lobbying activities does not cover all such activities undertaken by EEI. We note that during cross-examination the Staff witness indicated that he thought his recommendation was reasonable and that based on more current information, rather than a 25% reduction, he would consider a reduction of one-third realistic.

We will adopt the Staff adjustment of 25% related to EEI dues.

b. Estimating Methodology

In accordance with the Commission's directive in the 1983 test year general rate case decision, Edison developed its A&G estimates for test year 1985 using a budgetary methodology.

The methodology starts from recorded year 1982 as a base, with increases and decreases in activity resource levels for years 1983 through 1986 identified by the various departments that have expenses included in this A&G category. Accordingly, these estimates represent management's judgment of anticipated levels of activity and associated resource requirements by department.

Staff used a total of five estimating methodologies, only one of which was budgetary-based. The four nonbudgetary-based methodologies used by staff are as follows:

1. Adjustment of Edison's test year estimate to reflect the difference between 1983 recorded 1983 estimated A&G expense;
2. Application of a growth factor for kilowatt-hour sales and customers to Edison's 1983 recorded A&G expense;
3. Application of an historical growth factor for total A&G employees to Edison's 1983 recorded A&G expense; and
4. Adopting the 1983 recorded A&G expense as the 1985 test year estimate, without provision for growth.

Budgetary-based Adjustments

The budgetary-based adjustments made by Staff to Edison's 1985 test year A&G expense estimate are identified by account on the following table:

Differences Between Edison and Staff
Due to Staff's Budgetary-Based Adjustments
In A&G Expense
(Thousands of 1982 Dollars)

Account	Labor	Nonlabor	Other	System Total
920, A&G Salaries	$935	$ 0	$ 0	$ 935
921, Office Supplies & Expenses	0	30	0	30
922, A&G Transferred	(189)	(6)	0	(195)
930.2, Misc. General Expense	0	416	0	416
931, Rents	0	0	92	92
Differences due to Budgetary Adjustments	746	440	92	1,278

Of the five budgetary-based adjustments, the offsetting entry shown for Account 922--A&G Expenses Transferred, is a function of the amounts of expenses in Account 920--A&G Salaries, and Account 921--Office Supplies and Expenses. The Account 922 entry represents costs transferred to construction work orders. Staff and Edison are in agreement with respect to the 20.2% factor by which credits to Account 922 are determined. Therefore, there is no issue with respect to Account 922.

We will address the remaining issues in the section entitled Summary and Decision.

Adjustments Based on Difference Between 1983 Recorded and 1983 Estimated A&G Expense

Staff made various adjustments to Edison's 1985 test year A&G expense estimate to reflect the difference between 1983 recorded and 1983 estimated A&G expense. Staff's use of this estimating methodology resulted in downward adjustments in the following accounts:

Differences Between Edison and Staff
Due to Staff's Use of Ratio of 1983 Recorded
And 1983 Estimated A&G Expense
(Thousands of 1982 Dollars)

Account	Labor	Nonlabor	Other	System Total
920, A&G Salaries	$352	$ 0	$ 0	$ 352
921, Office Supplies & Expenses	0	825	0	825
922, A&G Transferred	(71)	(166)	0	(237)
924, Property Insurance	0	0	438	438
930.2, Misc. General Expense	0	399	0	399
931, Rents	0	0	95	95
Differences due to Use of 1983 Recorded for 1983 Estimated	281	1,058	533	1,872

Edison argues that in using 1983 recorded data for these estimates, Staff did not investigate the reasons for the differences between 1983 recorded and 1983 estimated expenses for these accounts, with the exception of a minor adjustment to reflect reorganization of Edison's Power Supply Department.

Edison contends that adjustments to its 1985 test year A&G expense estimates should not be based on a ratio between 1983 estimated and 1983 recorded expenses without first considering the reasons for the underexpenditures upon which that ratio is based. According to Edison, staff is asking the Commission to adopt a downward adjustment of almost $2 million which is founded upon nothing more than an assumption that the difference between recorded and estimated 1983 expenses will occur in the same fashion in 1985.

We will address these issues in the section entitled Summary and Discussion.

Adjustment Based on Growth Factor for Kilowatt-hour Sales and Customers

Staff adjusted various A&G accounts by applying a growth factor for kilowatt-hour sales and customers to Edison's 1983 recorded expense. Staff's use of this estimating methodology resulted in adjustments to the following accounts:

Differences Between Edison and Staff
Based on Staff's Use of a Growth Factor
For Sales and Customers
(Thousands of 1982 Dollars)

Account	Labor	Nonlabor	Other	System Total
920, A&G Salaries	$ 815	$0	$0	$ 815
922, A&G Transferred	(165)	0	0	(165)
Differences Due to KWh Sales and Customer Growth Factor	650	0	0	650

Staff utilized this estimating methodology in evaluating the Company's A&G estimates for Communications and Revenue Services and all Data Processing activities with the exception of contract employee expense. Specifically, this Staff methodology applied to the 1983 recorded expenses for these two departments, a factor of 9.05% for kilowatt-hour sales growth, and a factor of 3.56% for customer growth.

Staff applied the kilowatt-hour sales and customer growth factors upon the premise that they reflect the utility's needs in the areas of Data Processing and Communication and Revenue Services in the short-term. Edison notes that implicit in this premise is a correlation between growth in sales and customers and resource requirements for Data Processing and Communication and Revenue Services.

Edison argues that Staff has not introduced any evidence supporting its premise that a correlation exists between kilowatt-hour sales and customer growth on the one hand, and the A&G activities of Data Processing and Communications and Revenue Services organizations on the other hand. Indeed, Edison contends that it is unlikely that such a relationship exists. Therefore, Edison submits it would not be reasonable to adopt Staff's downward adjustment of $650,000 in these accounts, based upon a correlation which Staff agrees is indirect and unsupported by any kind of analysis.

Edison notes that its witness testified at length regarding new informational, accounting, and regulatory requirements which the Company faces, for which the most cost-efficient means of supplying information is through use of computers. Approximately 50% of the increase in data processing resources and funding levels between 1982 and 1985 is associated with regulatory requirements whereby the Company is required to do

business in a certain manner or provide and maintain specific types of information in specific manners. Edison cites as one example of the use of data processing systems that has increased recently involves the growing number of billing factors resulting from offset clauses with respect to which the Company is required to identify revenues and sales, and keep track of balancing accounts. According to Edison, these data processing activities are expected to be further impacted in the future.

According to Edison, increases in regulatory requirements create a need for complimentary resources in the area of Communication and Revenue Services, as well as data processing, all of which has a layering effect with respect to activity increases and demand on the Company's resources.

We will address these issues in the section entitled Summary and Discussion.

Adjustments Based on Historical Growth Factor for Total A&G Employees

Staff adjusted various A&G accounts by applying an historical growth factor for total A&G employees to Edison's 1983 recorded A&G expense. Staff's utilization of this methodology resulted in adjustments in the following accounts:

Differences Between Edison and Staff Based on Staff's Use of a Growth Factor For Total A&G Employees (Thousands of 1982 Dollars)

Account	Labor	Nonlabor	Other	System Total
920, A&G Salaries	$128	$ 0	$0	$ 128
921, Office Supplies & Expenses	0	650	0	650
922, A&G Transferred	(26)	(131)	0	(157)
923, Outside Services Employed	0	1,771	0	1,771
Differences Due to A&G Employee Growth Factor	102	2,290	0	2,392

Staff applied this estimating methodology to the A&G expenses applicable to the right-of-way and Land Department and to the expense for contract employees in the Data Processing Department. The methodology used by Staff involves application of a growth factor of 6.53% to Edison's 1983 recorded expenses. This growth factor represents the historical growth in total A&G employees for the period 1978-1982.

Edison argues that as in the case of Staff's adjustment reflecting kilowatt-hour sales and customer growth, discussed in section (3), above, implicit in this methodology is the premise that a correlation exists between A&G expenses and historical growth in total A&G employees.

Edison further argues that staff has provided no supporting analysis with respect to its premise that a correlation exists between A&G expense and growth in total A&G employees. With such limited support, Edison submits that it would be unreasonable to adopt Staff's recommended downward adjustment of almost $2.4 million.

We will address these issues in the section entitled Summary and Discussion.

Adoption of 1983 Recorded Expense Without Provision for Growth

Staff adjusted various A&G accounts by adopting the 1983 recorded amounts as 1985 test year estimates, without provision for growth. Staff's use of this methodology resulted in adjustments to the following accounts:

Differences Between Edison and Staff
Based on Staff's Use of 1983 Recorded Expense
Without Provision for Growth
(Thousands of 1982 Dollars)

Account	Labor	Nonlabor	Other	System Total
920, A&G Salaries	$131	$ 0	$0	$131
921, Office Supplies & Expenses	0	107	0	107
922, A&G Transferred	(27)	(22)	0	(49)
930.2, Misc. General Expenses	96	210	0	306
931, Rents	0	78	0	78
932, Maint. of General Plant	0	364	0	364
Differences Due to Use of 1982 Recorded For 1985 Estimate	200	737	0	937

Edison argues that Staff's application of this methodology is not supported by any record evidence; furthermore, Staff made no attempt to validate its no-growth assumption with respect to the A&G activities to which this methodology was applied. Edison notes that it has its estimate reflected activities which have exhibited decreasing growth or no growth. Edison further notes that the specific items in which there were decreases or no increases in A&G activities between 1982 and 1985 were identified for the record.

We will address these issues in the section entitled Summary and Discussion.

c. Summary and Discussion

Edison states that it has complied with the Commission direction in Edison's 1983 test year general rate case, by utilizing a budgetary approach in estimating 1985 test year A&G expense estimates. For each increase and decrease in activity level, the Company provided specific justification. Edison's estimation process incorporated the impact of influences such as an increasingly complex business environment, an increase in regulatory activities, and an increase in staffing requirements due to increased financial and business complexities. The estimates also incorporated the impact of the need to coordinate with many third-party enterpreneurs in the development of alternative and renewable resources. It is Edison's contention that Staff did not consider the impact of these operating environment influences on Edison's A&G resource needs.

Edison argues that staff did not consider the growth in the number of exhibits or the size of exhibits contained in Edison's filings before the Commission in recent years. Edison notes that one Company witness testified regarding the impact of ever-increasing regulatory requirements on A&G activities:

> "...in 1981 the Company was involved in 209 rate-related proceedings versus 268 in 1983. Between 1976 and 1983 the number of major proceedings Edison has been involved in has increased approximately sevenfold; the number of pages contained in various filings has increased approximately 61 times; data requests questions have increased approximately ninefold; and the number of pages submitted in response to data requests has increased approximately 90 times. Such activity cuts across most A&G departments, but has put particular strain on the legal, data processing and revenue requirements departments of the Company. Increasing regulatory activity has also impacted those organizations involved in the nuclear area."

Similarly, Edison notes that although the Staff witness agreed that tax law changes constitute a form of regulatory requirement, he contends that Edison's existing work force is adequate to accommodate changes in tax laws. Nonetheless, Edison points out that he had not attempted to quantify the impact of the "massive tax" law change represented by the Economic Recovery Tax Act (ERTA) on the regulatory resources of the Company, nor had he attempted to quantify the impact on the Company's resources of tax changes represented by the adoption of the Tax Equality and Fiscal Responsibility Act (TEFRA).

Edison cites as an example of a regulatory requirement which required the development of a brand new data processing system is the FERC-mandated Continuing Property Records System, whereby the Company is required to account for all plant assets by retirement unit. Edison's witness testified that the development of this new accounting system will take some time to complete.

Edison argues that in contrast to the assumptions upon which Staff's estimating methodologies are based, the Company's use of a budgetary approach resulted in an identification of resource needs for the test year.

We conclude that the Staff's estimating procedures for A&G are generally appropriate since its task is to test the reasonableness of the utility's estimate and to offer alternative estimates where appropriate. However, there are areas in which we find the staff estimate to be on the low side and appropriate adjustments will be made in those instances.

We find that setting the appropriate level for A&G expense is a particularly troublesome task. The budgetary approach, which we recommended in Edison's last rate case has the inherent defect that it could readily be turned into a "wish list." Therefore, our approach here will be to look at the reasonableness of the total increase for each A&G account compared to prior recorded years.

Therefore, we will address the differences between Edison and staff by account. San Onofre unit 2 and 3 costs are excluded from the discussion since these costs are covered by a separate stipulation. Also, constant 1982 dollars are used throughout.

Account 920 - Administrative and General Salaries

Edison's estimate for 1985 is $82,333,000, staff's estimate is $79,455,000. Edison's request represents a 10.2% increase over 1983 recorded; staff's estimate equates to a 6.4% increase or 3.2% per year. We conclude that the increase resulting from the staff estimate provides for reasonable growth. Accordingly we will adopt the staff estimate.

Account 921 - Office Supplies and Expenses

Edison's estimate for 1985 is $22,559,000, staff's estimate is $20,947,000. Edison's request represents a 10.4% increase; staff's estimate equates to a 2.5% increase. We conclude that staff's estimate is reasonable and provides enough margin for necessary growth. An additional $18,000 will also be included for the postal rate increase, for a total of $20,965,000.

Account 922 - A&G Transferred

There is no dispute regarding this account. The difference between Edison and staff is due to differences in Accounts 920 and 921.

Account 923 - Outside Services Employed

Edison's estimate for 1985 is $6,103,000; staff's estimate is $4,332,000. Edison's request represents a 39.7% increase over 1983 recorded; the staff estimate represents nearly a 1% reduction. We conclude that staff's estimate is reasonable.

Account 924 - Property Insurance

Edison's estimate for 1985 is $7,799,000; staff's estimate is $7,361,000. Edison's estimate represents a 68% increase over recorded 1983; staff's estimate equates to 58.6% increase. Based on 1983 recorded, we conclude that the staff estimate is reasonable.

Account 930.1 - Miscellaneous General Expense

Edison's estimate for 1985 is $27,541,000, staff's estimate is $25,782,000. Based on 1982 and 1983 recorded, we conclude that the staff estimate is reasonable.

Account 931 - Rents

Edison's estimate for 1985 is $2,901,000, staff's estimate is $2,636,000. Based on 1982 and 1983 recorded, we conclude that the staff estimate is reasonable.

Account 932 - Maintenance of General Plant

Edison's estimate for 1985 is $9,404,000, staff's estimate is $9,040,000. We conclude that staff's estimate which is based on 1983 recorded does not allow for reasonable growth. Accordingly, we will adopt Edison's estimate.

d. Adjustments

(1) Westinghouse Litigation Costs

Staff adjusted downward Edison's estimate for Account 924--Property Insurance, in the amount of $1,501,000, representing the Company's estimate of expense associated with its pursuit of legal remedies against Westinghouse regarding the degradation of steam generator tubes at San Onofre Unit 1. This litigation was ordered to be undertaken by the Commission in the Company's 1983 test year general rate case.

Edison believes this item to be more properly characterized as a legal expense, as opposed to a nuclear-related expense. However, the Staff witness testified that this adjustment was made on the basis of the item being nuclear-related, and that the reasonableness of the item would be addressed during the nuclear Results of Operations phase of this proceeding.

This item is covered by the stipulation.

(2) San Onofre Unit 1 Personnel

Although Edison did not identify any data processing personnel as being directly associated with San Onofre Unit 1, staff excluded three data processing positions which staff believes are properly chargeable to SONGS 1-related activity, resulting in a net reduction in A&G expense of $17,000.

This item is included in the stipulation.

(3) San Onofre Unit 1 A&G Expense Charged to Others

Edison included in its estimate of A&G expense charged to others a credit in the amount of $1 million, representing the A&G expense that would be billed to SDG&E. At staff's request, Edison removed the credit for A&G to be charged to SDG&E and included it in its A&G exhibit for consideration in the nuclear phase of this proceeding.

This item is included in the stipulation.

(4) Franchise Fees

Staff included uncollectible expense as a reduction to the amount of revenues subject to franchise fees, resulting in a downward adjustment to Edison's estimate of franchise fee requirements in the amount of $221,000. Edison does not deduct uncollectibles from the amount of revenue subject to franchise fees, because the Company's franchise contracts do not provide for such a reduction.

The payments made by Edison to cities for franchise fees are based on revenues billed to customers within each city covered by a specific franchise agreement. The individual contracts between Edison and the cities provide for determination of the franchise fees based upon "gross annual receipts" which the Company has interpreted to mean revenue billed.

We will adopt Edison's method of calculating franchise fees because Edison is legally required to make payment to the cities on the amounts billed rather than revenues received from customers.

(5) Pensions and Benefits - Account 926

The difference between Edison and staff is due to the difference in number of employees resulting from the respective Company and staff estimates of labor expense, and the difference in labor escalation rates as discussed elsewhere in this brief. The difference amounts to $5.2 million. The adopted level of expenditure will be calculated on the same basis but will reflect the number of employees allowed for in the adopted levels of expenditure for the other accounts.

(6) Research, Development and Demonstrations Expense

A complete discussion of RD&D expenses is included in the section entitled Research Development and Demonstration.

e. Lucerne Valley Licensing Costs

Edison submitted testimony in support of its request to recover in rates expenses totaling $7,398,000 resulting from the now-terminated licensing activities associated with the Lucerne Valley Generating Station Project (Lucerne Valley). The Company is not seeking recovery of $4,389,000 of AFUDC associated with the project, nor does the requested amount include $432,000 in costs which have been transferred to the Solar 100 project. The Company is requesting that recovery of the licensing activity expenses be amortized over four years.

Staff analyzed the materials supporting Edison's request, and recommends that the Commission allow the Company to recover the full amount of the requested Lucerne Valley licensing costs.

During hearings in this case, the Commission issued an Order Modifying D.83-12-068 and Denying Rehearing in PG&E's Test Year General Rate Case (Order). The Order dealt with the treatment to be accorded costs for certain projects abandoned by PG&E. In the Order the Commission set forth guidelines with respect to utility recovery of costs associated with abandoned projects. In particular, the Commission emphasized:

> "...that the utility bears the burden of proof of reasonableness, not only with respect to the planning and conduct of a given project, but also regarding the cancellation, which must have occurred promptly when conditions warranted ... we will continue to rigorously apply the criterion of reasonable managerial skill to costs deriving from such projects..."

which should be addressed in proceedings in which a utility has requested recovery of costs for a canceled project.

In support of the reasonableness of its actions, Edison states that in the early 1970's the Company identified a need for additional intermediate and semipeaking type generation; however, air pollution control regulation prevented operation of new conventional oil-and-gas fired generating units. In 1973, the Company filed a series of applications for permits to construct and operate a combined cycle generating facility at a site in the Upper Johnson Valley. This site had been selected as the preferred of three alternate sites on the basis of air quality considerations. These applications were filed with various public agencies including the Commission.

In early 1974, due to reduced forecasted demand growth, the operating date for the combined cycle project was deferred from 1977 to 1980. In 1975, the California Energy Commission (CEC) was created pursuant to the Warren/Alquist Act. Plants starting construction after 1977 were required under the act to obtain a permit from the CEC. Accordingly, in 1977 the Company withdrew its other state and local applications and filed with the CEC a Notice of Intention to File an Application for Certification (NOI) for a combined cycle project of 1290 MW. The NOI proposed four sites, one of which was Lucerne Valley or Upper Johnson Valley as it was originally called.

In 1979, the CEC rendered a final decision on the NOI filing, approving two sites (Lucerne Valley and Ormond Beach) for construction of either a combined cycle or a gas turbine generating station. The CEC directed Edison to include in its application for certification the option of a combustion turbine peaking facility (Peaker Park). In 1980, the Company filed an application for certification for a combustion turbine peaker park at the Lucerne Valley site on a contingency planning basis. Although the Project was not included in the Company's resource plan through 1990, by proposing certification of the Project on a contingency basis, the remaining licensing period could be shortened to a minimum.

In April 1983, the CEC denied the Company's application for certification on the basis of lack of need for the facility. While a Peaker Park at the Lucerne Valley site could meet the need for capacity in either decade (1984-93 or 1994-2003), at this time, the Company has no specific plans to develop either the combustion turbine or combined cycle project. Therefore, the Company has terminated this portion of the project siting efforts.

Edison is continuing with its development of a solar facility at the Lucerne Valley site, for which the site is also licensed, and intends to retain the site as a viable location for a Peaker Park, a solar generating station, or other suitable technology. According to Edison this partially licensed site provides ratepayers with additional security against the possibilities of capacity shortages in the 1990's.

Edison notes that it has proposed numerous uses for the Lucerne Valley site and has progressed expeditiously through extensive licensing requirements imposed by various regulatory agencies at the local, state, and national levels. Edison further noted that the viability of the site was established through the CEC's approval in 1979, and the project remained viable through April of 1983. Edison contends that this general rate case application was the earliest opportunity in which the Company could request recovery of the Lucerne Valley licensing costs.

We conclude that Edison has substantially complied with the guidelines prerequisite to recovery of costs associated with abandoned projects in its request to recover the Lucerne Valley licensing costs. Recovery of those costs should be authorized. No AFUDC is allowed and only direct costs for licensing activity expense shall be recovered. The amount of $7,398,000 will be amortized over four years and there will be no interest accrued on the unamortized balance.

10. Depreciation Expense

Edison's estimate of depreciation expense exceeds the staff's estimate by approximately $166,000.

While there is some disagreement between Edison and staff on the details of the depreciation expense, there is close agreement as to the total depreciation expense which should be allowed. With respect to the methodology for developing net salvage ratios and average service life, Edison does not agree with the methodology used by staff. However, Edison is willing to accept the final depreciation accrual rates recommended by staff with the understanding that, in so doing the Company reserves the right to contest staff's methodology in future proceedings.

We note Edison's reservations and commend Edison for compromising on this issue and on several others in the proceeding. Such compromise is appreciated since it allows all concerned to make more effective use of the limited time available.

For purposes of this proceeding, we will adopt the staff's depreciation rates which will be applied to the adopted levels of plant.

11. Tax Expense

Edison's estimate of the revenue requirement difference associated with tax expense for income taxes, ad valorem taxes, and other taxes exceeds the staff's estimate by approximately $3 million.

a. Income Taxes

Taxes are derived from estimates of revenue expense and plant expenditures. Differences between Edison and staff estimates in any of these areas result in differences in tax expense estimates. These differences are discussed in other sections of the brief; however, there is one difference between staff and Edison that involves a tax-related issue.

In determining both California and Federal income taxes for 1985, the staff witness used as reduction for removal cost an amount based on the 1980-1982 historical average. The removal cost in question represents the cost for removing or dismantling pre-1981 plant. Edison based its estimate on a 12-year average rather than three years used by staff. Edison's estimate resulted in a removal cost for both California and Federal income tax purposes of $15,531,000, whereas staff's deduction was $16,882,000.

Edison argues that it has consistently used a 12-year average in developing estimates of the removal cost for tax purposes. Edison notes that the Commission has consistently approved this method of estimating removal cost for tax purposes. Edison points out that the staff has offered no reasons for departing with prior Commission precedent in this matter.

We see no reason to change from a 12-year average. We will use Edison's methodology for calculating removal cost.

b. Ad Valorem Taxes

Edison's estimate of Ad Valorem Taxes is greater than the staff's estimate because of differences in estimates for plant in service, depreciation reserve, plant held for future use and materials and supplies. These differences are discussed in the section entitled Rate Base. The adopted ad valorem taxes will reflect the various adopted rate base items.

c. Other Taxes

Edison's estimate of other tax expenses is greater than Staff's estimate because of differences in the estimates of the number of employees and diffenences in the estimates of labor expense and labor escalation rates.

We will reflect the number of employees, labor expense and escalation rates contained in the adopted Results of Operations.

D. Rate Base

Edison's estimate of system rate base exceeds the staff's estimate by $48.3 million, a $9.7 million difference in CPUC jurisdictional revenue requirement. The differences are discussed below.

1. Plant Forecast

a. Fixed Capital

There are three items of disagreement between staff and the Company relative to the fixed capital. Staff takes issue with the Company's proposal to treat insulator change-out costs for the Big Creek to Magunden line as an expense. Staff contends that the cost to upgrade the transmission line south of Magunden should, in addition to being capitalized as recommended by Staff for the lines from Big Creek to Magunden, be shared equally with the Kern River Cogeneration Company (KRCC). Staff also proposes disallowing recovery of any portion of the Devers to Valley transmission line because staff believes that line will not be in service during the test year.

(1) Big Creek to Magunden Transmission Line

The first issue raised by staff with respect to the Big Creek to Magunden transmission line is the method of accounting for an insulator change-out being performed by Edison. The Big Creek to Magunden line connects Edison-owned generating facilities in the Sierra-Nevada Mountains with Edison's transmission grid. The facilities in question consist of transmission towers and conductors, as well as insulators on the Big Creek to Magunden transmission line, as well as the connecting lines south of Magunden. Edison began a program to improve the ground clearance of the conductors by replacing insulators with new insulators in a different configuration.

Staff reasons that since the change of the insulators will raise the transmission capacity of the line from 615 amps to 820 amps, there must have been a "substantial addition." Edison argues that the Uniform System of Accounts does not support staff's position.

The accounting treatment turns on whether the replacement of the insulators is properly considered to be a "substantial addition". If the insulator replacement is a substantial addition, Edison agrees that its accounting treatment would be governed by Electric Plant Instruction (EPI) 10.C.(1). As such, the cost would be capitalized and recovered over the useful life of the asset. EPI 10.C.(1) provides that:

> "(1) When a minor item of property which did not previously exist is added to plant, the cost thereof shall be accounted for in the same manner as for the addition of a retirement unit, as set forth in paragraph B.(1), above, if a substantial addition results, otherwise the charge shall be to the appropriate maintenance expense account." (Emphasis Supplied).

Edison argues that there have always been insulators on the Big Creek to Magunden transmission line. As a minor item of property, it must have had previously existed and result in a substantial addition in order to be capitalized. Since the property in question is a replacement, Edison contends that Staff cannot rely on this provision of the EPI to support its proposed accounting treatment.

Edison believes the cost of the insulator change-out program more clearly conforms with EPI 10.C.(3) which provides that:

> "(3) When a minor item of depreciable property is replaced independently of the retirement unit of which it is a part, the cost of replacement shall be charged to the maintenance account appropriate for the item, except that if the replacement effects a substantial betterment (the primary aim of which is to make the property affected more useful, more efficient, of greater durability, or of greater capacity), the excess cost of the replacement over the estimated cost at current prices of replacing without betterment shall be charged to the appropriate electric plant account."

Under this provision of the EPI, the cost of the insulator change-out could be accounted for in one of two ways. If the primary aim of the change is to make the Big Creek to Magunden line more useful, efficient or of greater capacity, the excess cost above the replacement cost would be charged to plant and the remainder expensed. The second option would be to charge all of the cost to maintenance as an expense.

We conclude that since the intended purpose is merely to improve ground clearance and return the line to its original design capacity, the latter option (expense treatment) is reasonable. Furthermore, in light of the relatively small amount of money involved (approximately $533,000 in CPUC Jurisdictional Revenue Requirement), the most expeditious solution is to allow the expense treatment proposed by Edison.

A second issue raised by Staff relates to the transmission lines south of Magunden. Staff contend that 50% of the cost to upgrade the transmission lines south of Magunden should not be recovered through rates. The KRCC project is located just north of Magunden substation. Edison agrees that some newly-added facilities north of Magunden which are directly related to the KRCC project should be paid for by KRCC. Staff has not taken issue with this allocation of costs for facilities north of Magunden.

The disagreement between Edison and staff is the treatment of costs for the upgrade of the 220-KV bulk transmission facilities south of Magunden. This upgrade is being performed to "restore these lines to their original design capacity." According to Edison restoration of these lines to their original design capacity is needed to reliably transport power from all resources north of Magunden, such as Edison's 775 MW Big Creek Hydro Electric Complex, not just the power from KRCC. The upgrading of these lines will improve reliability of service to Edison's customers.

Edison submits that the Commission orders require that costs not directly incurred for the benefit of a Qualifying Facility (QF), must be borne by the utility, not by the QF.

Edison argues that the evidence presented in this proceeding demonstrates that the cost of upgrading the bulk transmission facilities south of Magunden is a system requirement. Therefore, consistent with prior Commission orders, the cost of the upgrade should be borne by ratepayers not by KRCC.

We agree with Edison.

(2) Devers to Serrano Transmission Line

Staff has questioned the inclusion of the cost of the Devers to Serrano transmission line in rate base. Staff believes that the schedule for the project is unduly optimistic and that no portion of the line could be in service by mid-1985.

Edison conceded that the entire line will not be in operation during the test year. However, a portion of the line (the 40-mile segment from Devers to the Valley substation), is expected to be in service by June 1985.

Another issue was raised by Staff relative to the Devers to Valley transmission line. Staff believes that difficulty in securing easements in the San Gorgonio Pass could delay the project. The easements in question are sought from the Morongo Indians. The Morongo Indians wish to renegotiate the cost of the easement because of the delays which have already occurred. Edison believes that it will be successful in its negotiations with the Morongo Indians and this should not cause a delay. Nevertheless, Edison points out that it does have an alternative route through the San Bernardinno National Forest which bypasses the Morongo Indian Reservation. So, according to Edison, construction of the line does not hinge on the successful resolution of an agreement with the Morongo Indians.

On October 19, 1984 Edison submitted late filed exhibit No. 152, which confirms that Edison fully intends to have the Devers to Valley segment of the line in commercial operation by June 1, 1985.

The estimated cost to complete the Devers to Valley segment represents a weighted average rate base component of $13,272,000 contained in Edison's 1985 General Rate Case test year. The final Results of Operations for both staff and Edison include the effect of the in-service operation of the Devers-Valley segment in 1985. According to Edison, all other facilities associated with the line will be complete and in service by June 1, 1986.

We will reflect the above schedule in the adopted rate base.

2. Property Held for Future Use

Staff proposed a $200,000 reduction to land held for future use to reflect a lower cost of real property Edison intends to purchase in the Victorville area. Edison plans to move its district office to a more centralized location which will allow a number of services to be consolidated. Staff does not take issue with the plan to consolidate the facilities, staff merely objects to the projected value of the proposed site. The $200,000 disallowance represents a 50% reduction in the projected price of the property. Staff's estimate was based on conversations with a number of real estate salespeople in the Victorville area.

Edison had two independent appraisals of the land's value, one by an outside appraiser and one by an Edison staff appraiser. Both estimators independently arrived at approximately the same value per acre for the site. These estimators would place the value of the property at between $525,000 and $555,000 respectively.

We conclude that $400,000 for the site is reasonable. We will adopt Edison's estimate.

3. Working Cash

The staff method of calculating working cash allowance reduces Edison's revenue requirement by $9.0 million.

The working cash allowance compensates investors for funds provided by them which are committed to the business for the purpose of maintaining minimum bank balances and for paying operating expenses in advance of receipt of offsetting revenues.

Determining the amount of working cash allowance usually involves the preparation of a lead/lag study. This study attempts to match the average delay in payment of expenses with the receipt of revenues over the course of a year. These studies are familiar tools of regulation and no dispute exists between staff and Edison as to the mechanical application of the lead/lag analysis. Staff and Edison differ markedly, however, in the way income taxes should be calculated for the working cash allowance. Edison used 85.63 lag days for Federal Income Taxes (FIT) and 76.06 lag days for California Corporate Franchise Taxes (CCFT) and included Deferred Investment Tax Credit (ITC) at zero lag days. In addition, Edison, consistent with the Commission's procedure as set forth in Standard Practice U-16, "Determination of Working Cash Allowance", dated September 1968, included uncollectibles in its lead-lag study. The remaining difference results from differing estimates of revenues and expenses as described in other sessions.

Staff used 118.55 lag days for FIT and 81.71 lag days for CCFT and included ITC with its estimated FIT payments at 118.55 lag days. Staff also excluded uncollectibles from its lead-lag study consistent with its recommendation in Edison's last General Rate Case and Pacific Gas And Electric's 1982 and 1984 Test Year General Rate Cases. Staff used a revised Standard Practice U-16.

Edison contends that staff has not calculated the level of income tax payments -- for the working cash allowance calculation -- in accordance with applicable tax law. Specifically Edison takes exception to the staff's calculation which:

(i) includes the California Corporation Franchise deduction for Federal income taxes at proposed rather than present rates, and

(ii) uses deferred taxes to estimate current tax liability, and

(iii) uses the ratable flow-through ITC rather than the total ITC available.

Therefore, Edison argues that staff's level of estimated income tax payments is overstated in the working cash calculation because of these three factors. Staff's position is that tax benefits should be flowed through to the ratepayers to the maximum extent permitted by the law. In accordance with this basic precept, the staff calculated Edison's working cash requirements by considering the authorized tax expense and the optimum timing of the tax payments. According to staff, the essence of the dispute is that staff, in its working cash calculation, wishes to flow through to ratepayers all the benefits available to the utility; Edison wishes to "double dip," i.e. taking the benefits of tax normalization that are inherent in federal tax policy and seeking to capture those benefits again in the working cash computation.

Staff argues that ratepayers pay, on average, nearly three times as much for tax expense in rates as Edison actually pays in taxes. Staff acknowledges that this is the intent of the Congress in enacting tax legislation which favors utilities. But staff emphasizes there is no policy, congressional or otherwise, which requires the utility's working cash calculation to allow the utility to benefit twice from the creation of these "phantom taxes." Consequently, staff calculated the utility's working cash needs based on the most beneficial (to ratepayers) payment date for FIT and CCFT; staff included deferred ITC in its calculations; and staff adjusted for uncollectibles in accordance with Practice U-16.

We note that on the subject of working cash allowance, we stated:

> ". . . . In estimating the working cash allowance for ratemaking, only the specific allowable-ratemaking expenses should be used in the lead/lag study. To reduce the allowable income taxes by the amount of unamortized ITC (thus deriving taxes as paid) in the lead/lag working cash study is to mix ratemaking taxes with taxes as paid. The expenses and revenues in this case have to be on the same bases. The allowable-taxes are derived from the allowable revenues and expenses and those same taxes should be used for the working cash determination.
>
> "The staff's method has been the Commission's practice in the past and was used to determine the working cash allowance in [other cases]. . ." (D.92366, 4 CPUC 2d at 484-485.)

Therefore, consistent with our past decisions, we will adopt the staff method of reflecting income taxes in the working cash allowance calculation.

Another issue related to calculation of working cash allowance is the treatment of uncollectible expense.

Staff excluded uncollectible expense from its calculation of working cash. Edison argues that this exclusion is inconsistent with long-established Commission policy. Edison, in making its working cash calculation, included uncollectible expense at zero lag days. Edison points out that this is exactly the same method approved by the Commission in Standard Practice U-16. According to Edison this policy is sound because there are no cash payments associated with uncollectibles in the context of lead lag studies.

When Edison states that it included uncollectable expense in the lead-lag study at zero lag days this means that, in effect, Edison is requesting compensation for carrying charges for an uncollectable dollar amount over a period equal to the revenue lag, 40.52 days.

Edison overlooks the fact that the uncollectable amount is not an expense but a revenue adjustment. By allowing Edison the uncollectable revenue as an expense in the Summary of Earnings the Commission in effect inflates the authorized revenue requirement by the same amount so that the rates based on this inflated revenue requirement will give Edison the correct rate of return <u>despite</u> the fact that the uncollectable account is not collected.

Therefore, with regard to uncollectables, Edison is not experiencing the necessity of paying out money, nor is it receiving less revenue than it is entitled to and there is no carrying cost of money involved for which Edison should be compensated.

In summary, we will adopt the staff method of calculating working cash allowance. However, the adopted working cash allowance will be calculated on the basis of the results adopted. This calculation is set forth in the tables included at the end of the Results of Operations Section of this opinion.

We urge staff to issue a correction to D-16 to avoid having to litigate this issue in every major utility rate case.

4. <u>Load Management Programs</u>

Staff and Edison agree on the estimated capital cost for Load Management programs. Staff had originally sought to reduce the number of residential air conditioning cyclers from 24,000 to 15,000 units. However, staff witness Ahern endorsed Edison's 24,000 unit proposal and the level of effort is consistent with the California Energy Commission's recommendation. The minor difference between Edison's and staff's estimate of rate base associated with Load Management programs is due to slightly different methods of calculating rate base.

E. Jurisdictional Allocation

This relates to the allocation of adopted test year 1985 expense and return between the jurisdictions of the Commission and the Federal Energy Regulatory Commission. Staff takes no issue with respect to the method adopted by Edison. We will adopt Edison's jurisdictional allocation for purposes of this proceeding.

F. Net-To-Gross Multiplier

Edison and staff disagree as to the proper method for calculating the net-to-gross multiplier. Edison followed the method which was adopted by the Commission in D.82-12-055, Edison's test year 1983 general rate case decision. Edison argues that the Commission thoroughly investigated the method to be used to calculate the net-to-gross multiplier in that proceeding. Edison notes that staff, as it did in that case, calculated its net-to-gross multiplier by first subtracting uncollectible expense from total revenue and then multiplying the net by the franchise fee percentage to determine the franchise fee requirements. According to Edison, the Commission specifically rejected this approach and found that Edison's method of not subtracting uncollectible expense from total revenue before calculating franchise fee requirements was proper. We agree with Edison.

G. Summary of Earnings

The adopted summary of earnings and the various elements that make up the summary of earnings are set forth in Appendix B.

V. COMPETITIVE BIDDING

As part of the filing in this proceeding, Edison was directed to submit information regarding its competitive bidding procedures. Staff directed Edison to describe its bidding procedures and to provide assurance that Edison's contracts were awarded on a competitive basis. Staff analyzed Edison's competitive bidding procedures, and made one recommendation regarding Edison's procedures. Staff recommended that Edison work with staff to develop a method to track procurement activities below the $250,000 award level. Edison believes that staff's recommendation is reasonable and should the Commission order staff's recommendation be adopted, the Company believes that procedures can be implemented to meet staff's suggestions.

The staff recommendation is reasonable and should be adopted.

VI. FEMALE/MINORITY BUSINESS ENTERPRISES

A. Overview

The Commission conducted a comprehensive generic proceeding, Case 10308, examining the Female/Minority Business Enterprises (F/MBE) procurement practices of all California investor-owned utilities. The Commission issued D.82-12-101 dated December 22, 1982 in which Edison and the other utility respondents were directed to file specific information regarding their F/MBE programs with each NOI for a general rate increase. The Commission also ruled that the information submitted by each utility with its NOI would be reviewed in the context of that utility's general rate case proceeding.

In compliance with that decision, Edison submitted testimony regarding its F/MBE programs with its NOI for the present case. This exhibit described Edison's F/MBE program, including Edison's objectives, statistics, and reporting procedures. Staff submitted testimony which examined the information which Edison had submitted. Staff found that Edison's F/MBE submittal was basically in compliance with the Commission's decision in Case 10308. Evidentiary hearings on Edison's and staff's exhibits took place on June 5, 1984.

On June 13, 1984, the Commission issued D.84-06-111 in the Pacific Bell rate proceeding, which developed specific findings and orders with regard to Pacific Bell's F/MBE program. On July 13, 1984, the ALJ directed Edison and staff to file additional evidence, as late-filed Exhibits 125 and 126 respectively, addressing the question of whether the Commission's findings and orders in the Pacific Bell decision should be applied, as written, to Edison's current F/MBE program. The late-filed exhibits were received on August 13, 1984, and Edison's reply comments on the additional evidence were submitted on August 27, 1984.

In late-filed Exhibit 126, staff contends that the ordering paragraphs of the Pacific Bell decision are "implicitly generic" and therefore apply to Edison. Although Edison has entered testimony in this proceeding in which it proposes to implement the general requirements set forth in the Pacific Bell decision, Edison takes exception to staff's contention that the Pacific Bell decision should be made binding on Edison as a procedural matter.

The Pacific Bell decision ordered Pacific Bell to meet with certain specified representatives of recognized minority groups, following which Pacific Bell is to draft and submit to the Commission, as part of its next general rate case filing, a proposed tracking procedure. The Commission set forth specific required components of that proposed tracking procedure, as follows:

> "a. Stated-year 1986 female and minority goals for the ethnic classifications used by the State of California...
>
> "b. Reporting categories of purchase of or contracts for similar goods or services aggregating $5 million or more.
>
> "c. A report covering F/MBE activity in 1984 shall be submitted on March 1, 1985. Thereafter, PacBell shall file semiannual reports on March 1 and October 1 of each year. The March 1 report shall cover F/MBE activity from July 1 through December 31 of the prior year and the October 1 report shall cover F/MBE activity during January 1 through June 30."
> (D.84-06-111, Ordering Paragraph 21.)

B. Staff's Additional Requirements

In late-filed Exhibit 126, staff recommended that, in addition to the F/MBE requirements set forth in the Pacific Bell decision, Edison should also: (1) file stated-year 1986 F/MBE goals for the ethnic classifications used by the State of California, without waiting for Edison's next general rate case filing; and

(2) report categories of purchases and contracts for goods and services aggregating $2.5 million or more, as compared to $5 million or more as set forth in the Pacific Bell decision.

Edison argues that if the company is to implement the basic elements of staff's proposed F/MBE requirements, the company's current F/MBE program must be expanded, which will require authorization of additional annual F/MBE program funding by the Commission. In addition, Edison submits that in order to accommodate staff's proposed F/MBE requirements, certain minor modifications of those requirements should be adopted in the decision in this case. These modifications are discussed below.

1. The Establishment of Goals

Edison argues that if its F/MBE program is expanded to accommodate staff's proposed requirements, it is important that Edison be permitted the flexibility to redesign its current F/MBE program, and to develop the start-up phases of its revised program. Specifically, as the program is modified to include the same ethnic classifications used by the State of California, Edison should be permitted the necessary time to collect historic and reliable procurement data for each of the ethnic classifications. Edison's F/MBE witness stressed that the collection of this data is necessary to provide a realistic basis to develop meaningful goals for each ethnic classification. Edison currently estimates that a minimum of one year is required, following modifications to Edison's data collection system, in order to collect and analyze the data required to develop meaningful goals.

Edison has proposed to meet with the following F/MBE groups, among others, when developing realistic, meaningful goals: United Indian Development Association, Asian Business Association, Latin Business Association, Black Business Association, and the National Association of Women Business Owners. According to Edison, these groups are representative of F/MBE suppliers in its services territory.

Additionally, Edison urges the Commission to recognize that F/MBE goals should be developed in such a fashion as will permit administration of those goals within the context of procurement budget ceilings for the various Edison procurement projects. According to Edison this is necessary in order to enable Edison to satisfy its obligation to its ratepayers by minimizing the costs of procurement of materials and services.

2. Data Requirements

According to Edison, reporting F/MBE program results by the ethnic classification as used by the State of California for purchase categories over $2.5 million, as proposed by staff, will substantially increase Edison's efforts in data collection analysis, goal setting, and program reporting. Edison points out that in its original testimony in this case, staff proposed a reporting format consisting of a matrix with 40 reporting elements. Edison contends that the new reporting requirements set forth in staff's late-filed Exhibit 126 would substantially increase the number of matrix reporting elements from 40 to several thousand.

Edison proposes to establish F/MBE goals initially in the current general procurement categories of Commodities, Construction, and Services. Edison's modified reporting format will produce a reporting matrix with 608 reporting elements rather than several thousand reporting elements which would result from adoption of staff's recommendation. Edison provided a sample of its proposed reporting structure for the record. According to Edison the modified reporting format which Edison has proposed will meet the intent of the basic elements which staff has proposed, and accurately report important program results in a direct and comprehensive manner. Therefore, Edison submits that its proposed reporting format should be adopted by the Commission.

3. Additional Funding Required

Edison estimated that start-up costs associated with expansion of its F/MBE program, totaling $28,000, will be incurred

in 1984. Edison also projected annual costs beginning in 1985, of $420,000, which costs are incremental to Edison's existing F/MBE program. Edison's current annual costs range between $150,000 to $170,000. According to Edison, the incremental annual cost of $420,000 will be incurred in order to comply with the intent of the Commission's Pacific Bell decision.

Edison's projections of the incremental costs associated with expansion of its F/MBE program were supported by testimony regarding staffing, supervisory, data processing, and other resources associated with the expansion. This testimony was neither controverted nor challenged by staff or any party to this proceeding. Therefore, Edison argues that the Commission should adopt the requested additional funding levels, if the Commission determines that Edison should undertake the proposed F/MBE program expansion.

C. Positions of the Parties

The positions of the parties that participated in this phase of the proceeding are set forth below.

1. Edison's Position

Edison agrees that it can incorporate staff's recommended F/MBE program changes, as set forth in staff's late-filed Exhibit 126, if staff's recommendations are modified as proposed by Edison. Edison believes that adoption of the staff's recommendations, with Edison's proposed modifications, will result in enhanced procurement opportunities and awards for F/MBE suppliers. Should the Commission decide to adopt staff's recommendations, Edison submits that the Commission should also authorize the full amount of additional expense, $420,000 annually, which Edison has estimated will be required to implement those recommendations.

2. Staff's Position

Staff argues that its recommendation is based upon the premise that the Pacific Bell order has generic elements applicable

to all California utilities, that D.84-06-111 articulates the Commission's policy with regard to F/MBE program goals, and that it is desirable to have a consistent and uniform reporting system developed that will be used by all utilities under the jurisdiction of the Commission. The staff contends that its additional recommendation made no substantive modification to the Commission's Pacific Bell order, but merely incorporated the elements of D.84-06-111.

Staff argues that in the counter-proposal contained in Edison's Exhibit 157, Edison proposes to implement its F/MBE program responsibilities by collecting data on qualified F/MBE suppliers, by meeting with minority groups which it selects to develop F/MBE representation goals, and by modifying the relevant reporting requirements. According to staff, Edison's emphasis, both in Exhibit 157 and in the testimony of its witness in this area, is upon data collection.

Staff notes that the incremental costs of its proposal will be $420,000 annually above the $150,000-$175,000 Edison currently spends on F/MBE program activity. Staff does not disagree on the amount requested by Edison.

The fundamental criticism staff has about Edison's proposal is the emphasis upon building a data base before any goals are established. According to staff, Edison's schedule calls for data collection over an extended period; not until 1986 does the company foresee developing any F/MBE goals. And yet, staff argues, the utility would spend more than half a million dollars during 1985 without any progress being made toward increasing F/MBE representation in Edison's contracts for goods and services.

Staff believes it is essential for program goals to be defined early in the process, in coordination with F/MBE representatives who are negotiating with other California utilities toward developing meaningful and attainable goals for F/MBE representation in public utility contract business.

3. Position of U.S. Black Chamber of Commerce, et al.

The Black Chamber of Commerce argues that the testimony in this proceeding shows the following:

- Although blacks represent 10-12% of the Southern California market, only one-half of one percent (0.5%) of Edison's contracts go to black business.
- Within ten years (1994), just one percent of Edison's contracts will go to black businesses. (On redirect Edison revised this figure to .5%.)
- Similar inefficiencies exist as to women and other minorities.
- A substantial number of contracts in which there are minority and female businesses are not included in Edison's reporting mechanism. For example, it provides no information on lawyers, accountants, insurance agencies, real estate or health care companies and professionals.
- Even in areas where Edison keeps records, and in which there are substantial numbers of minority and female businesses, it often provides no contracts to minorities and women. For example, Edison has never provided any travel business to minorities or women because it emphasizes large size as a precondition for contracts.
- Edison will not negotiate future goals with any member of the U.S. Black Chamber of Commerce Coalition. Instead, it intends to discuss goals only with organizations that, in fact, have never urged it to seek goals.

The U.S. Black Chamber of Commerce further argues that despite a request for additional expenses of $420,000 annually, the plan submitted by Edison fails to comply with the staff's primary recommendation that Edison file "stated-year 1986 E/MBE goals for ethnic classifications used by the State of California".

Also the U.S. Black Chamber of Commerce argues that Edison's opposition to goal setting is an attempt to delay progress in awarding to female and minority businesses their fair share of contracts. Regarding Edison's argument that "justifiable" goals cannot be formulated without a data base and that at least one year is necessary to gather the data required, U.S. Black Chamber of Commerce contends that there is no reason why goals cannot be established based on information now available.

D. Discussion

Before we address the major issue, which is the additional measures required for Edison's F/MBE program to be consistent with the Pacific Bell decision, we should comment on Edison's compliance with prior Commission F/MBE decisions. Accordingly, we note for the record, that apart from recommending a new reporting format for monitoring the accomplishment of Edison's current F/MBE program (exhibit 82), staff takes no issue with Edison's compliance thus far.

Turning to the Pacific Bell decision, we conclude there is no need to address the issue of whether the decision is generic and therefore binding on Edison. Edison states that it is ready to implement the general requirements of the Pacific Bell decision. Also, in this proceeding, we gave Edison the opportunity to be heard on the measures necessary to expand its F/MBE program so that it is consistent with the Pacific Bell requirements.

It should be noted that staff now seeks to impose more requirements on Edison than those covered by the Pacific Bell decision. Edison has expressed its willingness to comply with the staff recommendations but with some modifications. Specifically, Edison notes that the staff proposal would require matrix reporting elements to be increased from 40 to several thousand. Edison suggests 608 elements. Also, Edison has reservations about the $2.5

million reporting level recommended by staff and the $5.0 million level contained in the Pacific Bell decision. Edison's witness contends that these levels are counterproductive because much of the minority activity is under these levels and by prescribing such levels, much needed data will be excluded.

We agree with staff that there should be uniformity in reporting requirement among the utilities. The minimum requirements for F/MBE are set forth in the Pacific Bell decision. Edison sees no major problems with expanding its F/MBE program to be consistent with that decision, except that it needs an additional $420,000 annually for this purposes, for the development of the necessary data base.

We conclude that Edison's request is reasonable, except that for the test year we will allow Edison half the amount since there will be delays due to start up of the expanded program. We will allow the full amount of $420,000 for each of the attrition years.

Regarding the reporting elements, we will for the time being adopt Edison's proposal. It is reasonable that Edison be allowed one year to develop the necessary data base. However, we expect that by the time of Edison's next general rate case Edison's F/MBE program will be consistent with F/MBE requirements set forth in the Pacific Bell decision. By that time we expect Edison to have the necessary data base to move in the direction recommended by staff. Also, we expect Edison and staff to work together between rate cases on development of the data base so that there is better understanding of the problems involved.

Turning to the question of meetings with the U.S. Black Chamber of Commerce, the Edison witness testified that the company had no record of the U.S. Black Chamber of Commerce requesting to meet with Edison prior to the Pacific Bell decision. We note Edison has indicated its willingness to meet with the U.S. Black Chamber of Commerce and all F/MBE organizations active in its service territory.

Returning to the question of F/MBE uniformity among the regulated California utilities, we direct Edison to meet and confer at regular intervals with the other utilities and the staff. At the same time, we expect staff to vigorously pursue this matter with the utilities between rate cases. Joint workshops, which include the F/MBE organizations, are the most effective means to resolve the question of goals and data formats. By the time of the next general rate case we expect the various uncertainties related to the question of data base and the setting of reasonable goals to be resolved. The record in this proceeding is too inconclusive to set reasonable F/MBE goals for Edison at this time.

However, during the intervening period between rate cases, we expect Edison to achieve a significant increase in the dollar amounts and in the number of F/MBE contracts awarded. In its next general rate case, we expect Edison to demonstrate significant progress.

We note that the Pacific Bell decision prescribes eight ethnic reporting categories. In addition reporting is required on the basis of "male" and "female". At the oral argument it was generally agreed by the parties that the number of ethnic reporting categories should be reduced. Accordingly, we conclude that, at a minimum, data should be collected on the basis of the following ethnic categories:

(1) Black; (2) Asian; (3) American Indian; (4) Hispanic; (5) Caucasian White, and (6) All Others.

In addition reporting is required on the basis of "male" or "female".

While we expect Edison to collect data at least on the basis of the above categories, it is reasonable to set goals for the following categories: (1) Black; (2) Asian; (3) American Indian, and (4) Hispanic.

VII. RESEARCH, DEVELOPMENT AND DEMONSTRATION EXPENSE (RD&D)

Edison originally requested $50.6 million (1985 dollars) for its 1985 program. Due to stipulations and revisions, Edison's revised 1985 request is $46.9 million. Staff recommends $43.7 million. We conclude that an expenditure level of $45.1 million (in 1985 dollars) is reasonable. In addition, as recommended by staff we are authorizing expenditure of up to $1.0 million over a 3-year period for research on a low-cost electronic watthour meter.

A. Policy Issues

1. Overview

Edison states that the overall objective of its RD&D Organization is to provide short- and long-term options that enable it to operate as a more efficient and cost-effective electric utility to the benefit of its customers. The term "options" refers to information, decisions, performance criteria and new technologies for clean and efficient generation, transmission, storage, distribution, and conservation of electrical energy with minimal environmental and social impacts.

Staff does not disagree with these goals. As stated by the staff's policy witness William Ahern:

> "In general, we support SCE's programs at nearly the requested level. More than fourteen million dollars is for demonstration projects, particularly geothermal and wind projects, that are mostly in progress with a number of co-sponsors. An aggressive search for 'winner' technologies seems appropriate in light of federal RD&D cutbacks, the current uncertainties about future costs of all generating technologies, the need for accurate generation

cost estimates for developing long-run forecasts of SCE's avoided costs, the CPUC and Energy Commission's general policy emphasis on the development of renewable resources, especially resources such as geothermal brine that are concentrated in California, and the uncertainty about who will be future owners of generation technologies.

Staff notes that it is this desire to encourage the search for winner technologies despite the currently unanswerable questions about the future ownership of generation resources, that has led it to support much of the funding requested by Edison for RD&D.

Therefore, staff seeks to encourage Edison to keep the options open, to obtain the best leveraging of its research money that it can by aggressive use of research development by national organizations and by co-sponsorship of projects and by orienting toward that research which has the greatest likelihood of success.

While we generally agree with Edison and staff, our inquiry will focus on whether (1) Edison's overall RD&D proposal is consistent with the guidelines and requirements which the Commission adopted in D.82-12-005 and (2) whether certain specific programs for which Edison is seeking funding, are similar to programs which were denied funding in the most recent general rate cases of Edison, PG&E, and SDG&E?

2. Guidelines

The Commission articulated general policy guidelines for RD&D, in D.82-12-005, issued December 1, 1982 in OII 82-08-01, which was a rulemaking proceeding to adopt evaluation guidelines for RD&D projects for ratemaking purposes. D.82-12-005 emphasized that RD&D projects should support one or more of the following objectives:

- There should be a reasonable probability of providing benefits to the ratepayers (minimize expenditures on concepts with a low probability of success).
- Projects should be consistent with the utility's resource plan.
- Projects should not duplicate research currently, previously, or imminently undertaken by another utility or research organization.
- Projects should lead to environmental improvement.
- Projects should enhance public or employee safety.
- Projects should support the Commission's conservation objectives and promote conservation by efficient resource use or by reducing and/or shifting system load.
- Projects should develop new resources, particularly those resources which are renewable, and/or processes or otherwise further supply technology. The project should reduce reliance on finite, nonrenewable resources.
- Projects should improve operating efficiency and/or reliability or otherwise reduce operating costs.

Edison states that the individual RD&D programs proposed for test-year 1985 were screened to ensure that they (i) meet the Commission's objectives and (ii) satisfy Edison's own vigorous screening criteria.

3. Cost-Benefit Evaluation

In D.82-12-005 the Commission required that the utility present a cost-benefit analysis of each RD&D project when requesting funding. Edison believes that its showing is in full compliance with the Commission's directive to furnish a cost-benefit analysis so that those programs unlikely to produce beneficial results from a monetary standpoint will not be funded.

4. Project Ranking Criteria

Edison agrees that the guidelines in D.82-12-005 require a utility to rank its RD&D programs in order of priority or, as an alternative, to develop a priority matrix at six different levels of RD&D funding. Accordingly, Edison prioritized its programs into three groups as part of its direct showing in this case, and additionally provided a matrix at the 100 percent level of funding. Edison believes it is in full compliance with the guidelines.

Staff argues that Edison has not properly utilized either of the prescribed approaches and, in fact, has presented the Commission with no basis to determine what will happen to its RD&D program with alternative levels of funding. Staff contends that Edison has not provided any specific ranking system by program. Rather, three blocks of programs were presented. (Ex. 7 at 4-6, Table 4.1.) Staff notes that Edison's witness indicated that the blocks are in a priority order, i.e., the first block has higher priority than the second and that within each block the items are in approximate order or priority. Edison's witness further stated that although the company used a point system in reaching its priorities, he did not include it in his exhibit because he felt the numbers would be given too much weight.

With regard to the alternative approach, that of using multiple matrixes for various assumed funding levels, staff points out that Edison's witness acknowledged that the Commission cannot tell from his exhibit what in Edison's view would be the result of budget reductions exceeding 10 percent.

We agree with staff; however, for purposes of this proceeding it turns out that the shortcomings cited by staff do not materially impact our final decision. However, in subsequent proceedings, this is an important matter which Edison should resolve with staff at the NOI stage; because, we simply cannot use a hatchet on any utilities' proposed RD&D budget if we want to reduce it by, for example, 25%.

5. Reporting Format

In Exhibit 59, Appendix F, staff presents a recommended reporting format for use in future RD&D filings in general rate cases and the RD&D annual reports filed by Edison. Staff recommends that this reporting format be adopted by the Commission as a requirement for future RD&D submissions. Staff notes that the reporting proposal is similar to that which staff recommended and the Commission adopted in the PG&E and SDG&E general rate case decisions as applicable to those utilities. (D.83-12-068 at 329; D.83-12-065 at 28a.) Among other things it would require reporting be done at the project level rather than at the program level. According to staff, this greater level of detail would provide a much clearer understanding of the specifics of Edison's RD&D program.

We will adopt the staff recommendation.

We note, that at present, Edison provides staff with the following reports:

1. Annual Status Report on RD&D (September 15 Report) - Pursuant to D.82-12-005, Ordering Paragraph 2, Edison must report on the status of its RD&D projects for the previous year. The report describes each project in terms of objectives, cost-benefits, expenditures and accomplishments among others. The report must be filed by September 15.

2. CPUC Annual Report (March 31 Report) -- Edison files an annual report with the Commission that includes the FERC Form No. 1. A detailed analysis of all R&D expenditures broken down into FERC accounts including expenses and capital is included in this report to the CPUC. The report must be filed by March 31.

We see no need to increase these reporting requirements at this time. However, because of the three-year rate case cycle, we hold Edison responsible for keeping staff continuously informed, through meetings and letters, of its progress and shifts in program emphasis. Edison is advised to document these meetings and contacts, since we will not be prepared to give Edison the benefit of the doubt, should there be further complaints from staff in future rate case proceedings.

6. Third Party Use

Since there is uncertainty over who will ultimately develop future generation resources, staff is concerned that adequate mechanisms be in place to protect the ratepayer's interest with respect to research which they fund. If Edison has a technological breakthrough which proves significant only to generation developed by third parties, staff contends that patent licensing, avoided cost discounts, or some other mechanism must be available to protect the ratepayer investment.

For example, staff notes that Edison is pursuing research in several areas of renewable and alternative technologies. Whether the future development of those lies with the utility or elsewhere is not clear. According to staff, the concept of keeping options open and searching for "winners" makes it appropriate for Edison ratepayers to fund this research.

Staff submits that one possible concept is to require third parties who use Edison funded research and then sell energy or capacity to Edison to do so at some discount from full avoided cost. Staff policy witness Ahern indicated this to be a possibility but was hesitant to recommend it since, by necessity it would require the use of non-standard contracts, something the Commission has been trying to avoid.

Edison indicated that an avoided cost discount was in fact the way they had been handling this situation. With the use of standard offers, however, Edison has begun charging for the use of RD&D results as a cost along with connection charges that Edison imposes to connect a QF to the Edison system. A QF or Qualifying Facility is a cogenerator or small power producer.

Staff does not have a firm recommendation on the best way to handle this problem and suggests it is an appropriate subject for the OIR 2 proceeding. Staff, however, emphasises that the problem is one that must be addressed. Staff argues that only with adequate control over QF use of ratepayer financed RD&D can it really be appropriate for Edison to engage in research on generation technologies for which a QF rather than Edison might prove the ultimate developer.

We agree with staff, this is a matter which should be vigorously pursued in future OIR 2 proceedings.

7. Trend In Funding Levels

Edison's revised RD&D expense level for 1985 is $43,658,100 in 1982 dollars. A slightly higher sum is requested for 1986 ($45,155,000). The amounts can be broken into three categories: (1) core research, (2) demonstration operations and maintenance costs, and (3) contributions to the Electric Power Research Institute (EPRI). The table below gives some indication of the trend in these three main categories of expense for the years 1981 through 1984 compared with Edison's request for 1985 (revised) and 1986.

Research, Development, & Demonstration Expense
($000's)

Research Category	Recorded 1981	Recorded 1982	Recorded 1983	Recorded 1984	Requested 1985	Requested 1986
Core Research	11,771	10,777	9,645	12,231	15,689	14,997
Demonstrations O&M	1,929	6,759	12,103	15,013	15,058	13,878
Contributions to EPRI	12,842	8,462	12,230	13,450	12,911	16,280
Total	26,542	25,998	33,978	40,694	43,658	45,155

Notes: (1) 1981 expenses shown in current dollars.
(2) 1982-1986 expenses shown in constant 1982 dollars.
(3) 1984 expense reflects budget estimate.

Edison notes that from the above table it can be seen that approximately one-third of the 1985 request is directed at the core programs. The remaining two-thirds of the 1985 request is devoted to areas where according to Edison, the company can make only minor adjustments; Edison refers to contributions to EPRI (which are determined in accordance with external factors such as actual revenues and kWh sales) and O&M expenses for demonstration projects which Edison contends are relatively inflexible.

Viewed in the context of core research, Edison submits that its 1985 request is consistent with the stay-the-course policy. According to Edison, if the long-term interest of its ratepayers is the over-riding criterion, then the requested level of funding is appropriate.

Looking at Edison's 1985 request from a different viewpoint, the table below shows the budget trends in terms of the main research areas. It will be noted that the most significant increase, apart from EPRI, is in environmental improvement programs.

Comparison of
Expenditures by Research Area
(Thousands of Dollars)

Research Area	Recorded 1981	Recorded 1982	Recorded 1983	Recorded 1984	Requested 1985	Requested 1986
Environmental Improvement	4,086	3,660	2,620	2,555	4,867	5,137
Health & Safety	955	459	1,195	1,645	2,150	1,900
Energy Conservation & Efficient Resource Utilization	1,338	940	1,005	2,170	2,505	2,510
Renewable Energy Resources	3,215	9,049	10,650	13,130	13,325	11,750
Advance Energy Technologies	2,635	1,560	1,535	2,605	2,435	1,965
System Operations & Efficiency Improvements	899	1,040	695	1,055	1,370	1,470
Research Support to EPRI	12,842	8,462	12,230	13,450	12,911	16,280
Fuel Cell Write-off & Others	572	828	4,048	4,084	4,095	4,143
Total RD&D Expenses	26,542	25,998	33,978	40,694	43,658	45,155

Notes: (1) 1981 expenses shown in current dollars.
(2) 1982-1986 expenses shown in constant 1982 dollars.
(3) Fuel Cell write-off authorized by D.82-12-055.

Edison's RD&D programs are divided into six main research areas subdivided in 39 programs which in turn are subdivided into individual projects. It is at the program level where cost-benefit analyses and prioritization of projects is done. The table above shows the budget trends in each of the main research areas as well as the EPRI expenses and fuel cell write-off expenses for the years 1981 through 1984 compared with Edison's request for 1985 and 1986.

Since Edison report, Exhibit 7, and staff report Exhibit 59 provide a detailed description of the various programs, we will limit our discussion to the areas of controversy.

8. EPRI Expenses

The EPRI portion of the Edison RD&D budget is approximately one third of the total. EPRI is a "voluntary" organization of which the utility must be a member to obtain direct benefits of its research. It does not allow for partial membership and requires that its full dues assessment be paid. Not all electric utilities are EPRI members.

Between 1985 and 1986 Edison is projecting that the EPRI assessment they experience will go up while Edison's overall RD&D budget will decrease. Edison's witness indicated this was due to EPRI funds from member utilities being tied to sales and revenue, which are going up, while Edison's program is tied to the actual cost of the research being done.

Staff has concerns regarding the coordination of research with EPRI. Staff notes that there are a large number of research areas which are either not directly relevant to Edison's activities or are in areas this Commission has indicated California utilities should not be so engaged.

According to staff, it is unclear what true control any individual utility has over the direction that EPRI takes with its research expenditures. Edison's witness testified that they do have a say in what EPRI does through various liaison personnel and that there is a process for requesting that EPRI do work in a certain area. The Coolwater Coal Gasification plant was cited as an example of the benefits Edison derives from EPRI.

Staff further notes that the Commission has in past decisions indicated that work of a generic nature should not be pursued by California utilities but should be undertaken by such national groups as EPRI. Notwithstanding Edison's assertions, staff believes there are significant questions as to the ability of California utilities such as Edison to effectively ensure that EPRI does generic research which this Commission might deem beneficial to California.

As an example of this problem, staff points to the program for development of an electronic watthour meter, essentially generic research and of great potential benefit to California, which was previously undertaken by EPRI but allowed to lapse. We will return to this matter later.

Staff also has concern over its own ability to monitor the manner in which EPRI expenditures are made to ensure that research is being undertaken in a proper manner. Staff complains that unlike work done by regulated utilities, EPRI research reports are not generally available to staff scutiny until a research project is completed.

However, for this proceeding, staff recommends that with respect to payments to EPRI the adopted level of expense equal the amount actually billed Edison in 1984. (Late-filed Exhibit 60.)

We will adopt staff's recommendation.

9. Issues Related To Edison's 1983 Test Year General Rate Case Decision

During the course of the hearing the ALJ identified specific programs, for which Edison is seeking funding, which appear to be similar to programs for which the Commission denied funding in the most recent Edison, PG&E, and SDG&E general rate cases. The ALJ directed Edison to discuss, in briefs, the differences. Edison did provide such a discussion which is contained at pages 235-247 of its opening brief; the subjects are:

- Ecological Effects Criteria; Coastal and Marine Resources; Air Quality Management; Atmospheric Chemistry/Physics; Community Health Air Pollutants; Hazardous Waste Management; PCBs.
- NOx Reduction; And Energy Conservation And Management In Buildings.
- Advanced Bio-Beneficiation Of Fuels.
- Advanced Cogeneration.
- Renewable And Alternative Energy Research Deployment.
- Energy Recovery From Waste; Wind Conversion; Solar Troughs; Photovoltaics; And Solar Central Receiver.
- Coal Gasification Program.
- Methanol (New Project).
- Advanced Nuclear.
- Direct Combustion Of Coal.
- Plant Reliability And Efficiency Improvement.
- Meteorological Dynamics, And Robotics.

The discussion provided in Edison's brief generally answers the Commission's concerns and therefore need not be repeated here.

B. Test Year Expenditure Levels

Since all estimates are prepared in 1982 dollars and Edison and staff used different escalation factors to convert to 1985 dollars, this discussion will be in terms of 1982 dollars. On this basis, Edison's revised request is $43,658,100; staff's revised recommendation is $40,820,000. The staff recommended adjustments are discussed according to the six generic categories set forth below:

1. Acid Rain/Fog Research

Staff recommended that all research relating to acid rain/fog be eliminated from four RD&D Programs. This recommendation equates to an adjustment of $1,065,000. The items at issue and the adopted expenditure levels are set forth below:

Program	Edison	Staff	Adopted
	(Thousands of 1982 Dollars)		
Atmospheric Chemistry/ Physics	1,150	838	1,150
Meteorological Dynamics	675	567	675
Air Quality Management	286	214	286
Ecological Effects Criteria	818	245	818
Subtotal	$2,929	$1,864	$2,929

With respect to the first three items listed above staff does not dispute Edison's goals, merely the funding. Regarding the last item, the staff recommended adjustment is premised on Edison's ability to obtain the necessary information from other sources.

Edison notes that, pursuant to the Kapiloff Acid Deposition Act, the California Air Resources Board ("CARB") has an extensive five-year monitoring and research program in place. Currently, the CARB intends to spend $18 million for research in the following areas: 1) monitoring, deposition and atmospheric processes; 2) acquatic, terrestrial, materials, and health effects; and 3) emissions inventory and control technology. As of December 1983, 58 percent of CARB's research was in the South Coast Air Basin. Under the Kapiloff Act, the CARB is required to coordinate acid rain research in the State of California. However, Edison argues that in formulating the Kapiloff Act, the Legislature recognized that the CARB would not duplicate what the company was already doing. It is Edison's position that rather than the company being able to acquire information from the CARB, the Kapiloff Act implies that the CARB will obtain information from the company.

Edison submits that the proposed programs related to acid rain are a vital component of the study of acid rain in California. According to Edison, the CARB is spending a significant portion of its budget in the South Coast Air Basin on mobile sources of air pollution. Mobile sources account for a high proportion of air pollutants in the SCAB, thus air quality (not acid rain or fog research) becomes a primary concern of CARB. It is the South Coast Air Quality Management District ("SCAQMD") which has primary concern for stationary sources.

Edison argues that to date, the CARB research in the South Coast Air Basin has virtually neglected study of stationary elevated emission sources such as power plants. On the other hand, the company is the sole source of research information on the behavior of elevated source emissions in this unique area. According to

STATE OF CALIFORNIA
DEPARTMENT OF CORRECTIONS
PRISON INDUSTRY AUTHORITY

Certificate of Individual Microfilm or Other Photographic Reproduction

Section 14756, Government Code

I, the undersigned, hereby certify to the following in connection with the accompanying microfilm (photographic reproduction):

That I, Thomas Coupe', Industrial Supervisor, P.I.A. Micrographics or C-13413 an employee in the charge of Mr. Coupe', have been provided with access to the records, documents, instruments, plans, books or papers (hereinafter referred to as "records") of C. P. I. C. at C.M.F. Vacaville Ca. for the purpose of microfilming; that such access was provided with the consent of said person or entity; that such records are reproduced in the accompanying microfilm; and that each Department of Corrections P.I.A. of the State of California repeoduction includes the following identifying symbol, roll number VOL # 1023.

That pursuant to delegation of the Department of Corrections P.I.A., I am authorized to direct and control the reproduction of documents and records of the Department or of other persons and entities in the manner authorized by Section 14756 of the Government Code, and Section 1551 of the Evidence Code; to execute certificates as required by Section 1531 and 1551 of the Evidence Code; and to certify under the official seal of the Department.

That this microfilm of the above described records was taken under my direction and control on the date hereof and that it is a complete, true and correct copy thereof;

That the microfilming or other photographic processes were accomplished in a manner and on film which meet with the standard specification of the United States National Bureau of Standards and A.N.S.I.

That this certificate was made at the time of the taking of this microfilm.

WITNESS my hand and the seal of the Department of Corrections Prison Industry Authority

15 day of JAN. 1986

Thomas R Coupe'
(name)

california
prison industry authority

Edison, sensible and cost-effective emission control strategies, which are ultimately in the best interest of society and the company's ratepayers, cannot be formulated without such input. Finally, Edison points out that the SCAQMD recognizes the critical role of Edison's efforts and supports Edison's acid rain research programs.

On the other hand, staff contends that the Kapiloff Act provided significant appropriations for air quality studies and in spite of Edison's assertions, staff argues that the Act does not name Edison or direct them to do any studies at the company's expense.

We do not dispute that, especially because of the unique characteristics of the South Coast Air Basin, the problems resulting from power plant emissions are a matter of high priority. Also, we commend Edison for the work it has done thus far in setting up an extensive monitoring network in the South Coast Air Basin and sharing its data with the SCAQMD. In addition, we realize that if Edison should withdraw from this work it would cause a serious setback to the progress made thus far. On the other hand, staff has a valid concern regarding funding.

While we do not dispute that Edison's ratepayers should bear their own "clean up" costs, it does seem that Edison's ratepayers are bearing the lion share of clean up costs related to elevated emmissions. Therefore we expect Edison to take steps to obtain some funding from SCAQMD or other entities. In the next general rate case proceeding, we expect Edison to indicate what steps were taken to seek other funding for this program, otherwise, Edison will be faced with an appropriate disallowance.

2. Activities To Be Co-sponsored Or Done By Others

Staff recommends reduction of certain program funding on the grounds that:

a. The research is generic and should be done by EPRI or a similar organization; or

b. The research is beneficial but should be co-sponsored.

The items at issue and the adopted level of expenditure are set forth below:

Program	Edison	Staff	Adopted
	(Thousands of 1982 Dollars)		
Robotics and Artificial Intelligence	100	0	100
Electrical Systems	700	500	500
Advanced Bio-beneficiation of Fuels	100	0	100
Occupational Health	600	425	425
Community Health Air Pollution	750	547	547
Miscellaneous			
Transmission	12	0	0
Distribution	50	0	0
Advanced Nuclear	80	0	0
Total	$2,392	$1,472	$1,672

The adopted expense levels total a reduction of $720,000 to Edison's request for these items.

Edison agrees that generic components of these programs should be and are being done by others. However, Edison contends that it is this outside activity which has enabled the company to achieve an excellent record of leveraging its own research, to obtain results which are more directly applicable to the Edison ratepayers. Edison emphasizes that it does not propose to duplicate generic research but to maximize the use of the results of this outside research in developing applications specific to the Edison system.

In the Robotics and Artificial Intelligence program, Edison argues that its efforts will not duplicate generic research. Edison points out that this is one of the most rapidly advancing techologies and there is opportunity for applications to improve the efficiency and reliability of present and future generation and transmission systems. We will adopt Edison's estimate because we see a need for Edison to actively participate in this rapidly advancing field.

Edison agrees with staff's contention that there is a generic component to the electrical systems work being conducted by EPRI. With respect to the Electrical Systems program, however, the company is already performing generic research for EPRI. Therefore, Edison contends, it is quite cost-effective for the company to supplement this research effort with research that is only of marginal interest to other utilities, but of specific interest to the company and its ratepayers. We will adopt the staff estimate since we believe it does provide a reasonable level of funding for this program.

With respect to Bio-Beneficiation of Fuels Edison points out that its research efforts concentrate on western coals and fuel oils while most of the generic research in this area is being conducted on eastern coals and fuel oils. Edison argues that the latter could not be applied for use in Edison's generation system. We agree with Edison regarding the need to concentrate on western coals and fuel oils and will adopt Edison's estimate for this item.

Edison recognizes that some of its activities related to Occupational Health will benefit other western utilities. However, Edison submits that the company is trying to get co-sponsors for this work and has made this research conditional upon obtaining such co-sponsorship. Edison argues that funding for this program should be allowed because it will define the extent of health hazards from air pollutants to residents of southern California.

We conclude that the staff recommended expense levels for the Occupational Health and Community Health programs are sufficient for Edison to be active in these areas. Accordingly, we will adopt the staff estimates for these items.

Also, we will adopt the staff recommendation not to fund the Miscellaneous programs since we believe there is sufficient margin available for Edison to accommodate such matters.

Finally, regarding the Advanced Nuclear Program, we agree with the staff that this should be undertaken by EPRI or others. Accordingly, we will not provide funding for this program.

3. Activities Which Belong In Other Programs

Staff identified portions of six programs that it believes should be an integral part of Edison's Renewable Energy Siting Optimization program or Renewable and Alternative Energy Resource Deployment program.

The items at issue and the adopted level of expenditure are set forth below:

Program	Edison	Staff	Adopted
	(Thousands of 1982 Dollars)		
Solar Troughs and Ponds	150	120	120
Solar Parabolic Dishes	250	230	230
Energy Recovery from Waste	125	0	0
Advanced Micro Hydro	50	42	42
Wind Energy Conversion	350	100	100
Inland Natural Resources	650	605	605
	$1,575	$1,097	$1,097

The adopted expense levels total a reduction of $478,000 to Edison's request.

Staff believes that some overlap or duplication exists between the technology-specific programs identified in the table above, and two other programs proposed by the company: (1) Renewable Energy Siting Optimization (RESO) and (2) Renewable and Alternative Energy Reources Deployment (ERD).

Edison argues that there is no duplication between the activities or the funding. Rather all the programs are complementary since the six technology-specific programs provide input to the RESO and ERD programs. Therefore, Edison contends it would be inappropriate to exclude funding for the sub-elements as staff has recommended.

Staff notes that because of its concerns regarding overlapping or duplication, Edison provided rebuttal testimony. However, staff argues that a reading of the rebuttal testimony reveals no facts but merely an assertion that staff made an 'understandable' misinterpretation."

We agree with staff that the applicant has the burden to prove the appropriateness of the program. It is not the staff burden to disprove it. We will adopt the staff recommended funding levels for these items.

4. Activity Which Should Not Be Performed At Ratepayer Cost

Staff contends that expenses in the Hazardous Waste Management program related to the Workshop on Coal Combustion Waste and Risk Assessment Methodology Evaluation (workshop) should not be borne by Edison's ratepayers.

Edison's request, the staff recommendation, and the adopted level of expenditure are set forth below:

Project	Edison	Staff	Adopted
	(Thousands of 1982 Dollars)		
Hazardous Waste Management	$800	$725	$725

The adopted expense level totals a reduction of $75,000 to Edison's request.

Edison states that the purpose of the workshop is to assemble research and expertise on coal combustion wastes, and to integrate and apply these to cost-effective waste handling coal-fired facilities, including Edison plants. A workshop setting brings together many top workers in a field to focus on a specific problem. Edison contends that it is a very cost-effective method for gathering state-of-the-art information as it applies to Edison's operations.

We will adopt the staff recommended adjustment of $75,000 because we believe Edison can, by exercising a modicum of frugality with ratepayer funds, achieve the same objectives.

5. Expenses Which Should Be In A Different Proceeding

Staff recommends a $300,000 decrease in funding for the Coal Gasification program, indicating that cost recovery for activities related to the "Coolwater Coal Gasification Project" should be through the ECAC.

Edison agrees that operation and maintenance for the Coolwater plant is recovered through ECAC proceedings. However, according to Edison this program is totally separate from running the demonstration plant, and is instead an R&D assessment of the coal gasification process. Edison states that the program includes tests of the system at Coolwater, to see how it can be optimized compared to other coal gasification systems, to provide the best system for the company's use in the future. The staff recommendation is premised on the understanding that avoided cost payments for energy transmitted is to be the sole ratepayer involvement in the financial affairs of the Coolwater project and this is to be handled in ECAC proceedings.

We concur with staff; the staff-recommended adjustment of $300,000 is adopted.

6. Other Adjustments

Edison accepts staff's adjustment with respect to the level of funding for the Energy Conservation and Management in Buildings Program:

Program	Edison	Staff	Adopted
	(Thousands of 1982 Dollars)		
Thermography	90	0	0
Residential Energy Storage	90	0	0
Advanced Heat Pump	50	90	90
Subtotal	$230	$90	$90

We will reflect the above staff-recommended reduction of $140,000 in the adopted results.

C. Discussion

Staff notes that it has not recommended disallowance of the following programs: Methanol, Direct Combustion of Coal and Plant Reliability and Efficiency Improvement.

Staff further notes that while it has made disallowance recommendations with respect to several of Edison's programs, the basis for the disallowance was not related to the activity itself being improper, i.e., avoiding regulation, but to whether the work should be done by others, or was duplicative of work already being done.

On the subject of whether the activity itself was improper, Edison's witness testified that the introduction in the test year 1983 rate case of the term "avoidance of environmental regulation" led to a misunderstanding. It is Edison's position that what they were referring to then, as well as now, concerns demonstrating that their plants already meet certain standards so that additional (and, for the ratepayer, potentially costly) control facilities might not be necessary. This explanation leads staff to believe that Edison is not endeavoring to evade environmental control standards but is rather endeavoring to demonstrate existing compliance, or in the alternative, less costly means of compliance.

We agree with staff, that it is in the ratepayer interest for Edison to develop the least costly means of compliance with environmental regulations. However, there is a fine line between achieving least cost compliance and working to subvert environmental regulation. We have granted Edison's full request related to air pollution programs with the understanding that ratepayer funds are not to be used for the avoidance of environmental regulation. Edison should ensure that this policy is clearly understood by its employees.

Finally, we note that Edison's RD&D funding request has been granted nearly at the requested level with the exception of a few minor adjustments. This is because we conclude that Edison has proposed a balanced program which recognizes the special needs of the L.A. Basin and provides for research, with a number of co-sponsors, for winner technologies needed in view of the current uncertainties about future cost of all generation technologies.

Based on the foregoing discussion, the total reduction to Edison's revised request of $43,658,000 million for RD&D amounts to $1,573,000 million (in 1982 dollars).

D. Time-of-Use (TOU) Metering Research

In the staff report, policy witness Ahern stated:

> "A major problem in rate design is that not all customers are on time-of-use rates. With time-of-use rates the Commission can give customers more accurate price signals about the different costs they are imposing on SCE's system .... If all customers were on real time-of-use pricing, there would be no need for incentives for load management programs, as customers imposing loads at peak times would pay the relevant high costs. However, until high technology development brings down the cost of the required metering, it is not cost-effective to extend time-of-use metering to small use customers." (Ex. 58 at VII-14.)

Staff notes that TOU rates require sophisticated and, therefore, expensive metering devices so as to record not only the kWh usage but to also record demand and to record both of these on a time differentiated basis. Staff further notes that Edison indicated a current cost of $400-$450 per meter for metering devices to be used for one particular TOU program.

Because of the present high cost of TOU meters, staff recommends the funding, as an Edison RD&D project, the design and construction of a low-cost modern electronic watthour meter having a wide range of metering capabilities.

Edison concurs that research and development of such a sophisticated meter would be desirable. Apart from EPRI's abandonment of the project, Edison has not previously pursued development of such a meter on its own due to the lack of a clear signal from the Commission as to its views on wide implementation of TOU rates. Edison's witness noted that the same lack of signal may inhibit manufacturers from developing such a meter.

We agree with staff that a low-cost modern electronic watthour meter with a wide range of capabilities should be developed but we are not prepared to commit the ratepayer to indefinitely funding such a program without a clear understanding of the total price tag; the record contains no information on this subject.

However, based on the staff recommendation we are prepared to authorize funding for no more than three years to get a better understanding of the feasibility of this project. Accordingly, commencing 1985 we will authorize Edison to accrue expenses up to a total of $1.0 million through 1987 in an interest bearing memorandum account. We caution Edison that no expenditures or contracts entered into should extend beyond the three-year period. Edison will keep staff continuously informed of all major developments by letter. Edison will provide staff with a detailed accounting and progress report by the 31st of March each year. Edison may request recovery of these costs in its next general rate case proceeding but will have the burden of proving the reasonableness of these expenditures.

Staff submitted a late-filed Exhibit 148 entitled "Statement of the Development of Low Cost Modular Versatile Solid State Electronic Watthour Meter. We expect Edison to use this outline as the starting point for the program subject to modifications necessary to achieve the objectives of the project.

In view of the problems that staff currently has in monitoring on-going research undertaken by EPRI, we expect Edison to arrange for staff to have full access to all contractors and subcontractors involved in this project. Edison will arrange for staff to visit contractor facilities, as needed, to monitor progres.

In the next general rate case proceeding, we will examine possible replacement of electro-mechanical watthour meters with modern low cost electronic modular meters along the lines of the TOU meter discussed above. Also, we will review the question of expanding on the capability of the TOU meter design through modular capability to accomplish: (1) remote meter reading by the utility; (2) direct metering of presently master metered customers to make the pricing of energy sensitive to usage; and (3) provide customer usage information and display systems to assist customers in load control. We expect Edison to address these issues.

E. Three-year Rate Case Cycle

During the course of this proceeding, the Commission moved Edison from a two-year rate case cycle to a three-year cycle. The parties were directed to discuss the effect of this change on Edison's proposed RD&D programs.

Edison determined that only one of the thirty-nine component programs which comprise the company's total RD&D effort is scheduled to terminate prior to attrition year 1987. That program is entitled "Renewable Energy Resource Siting Optimization"; it is scheduled for completion on December 31, 1985, and will not require

funding in either 1986 or 1987. All of the remaining RD&D programs are scheduled to continue at least through attrition year 1987.

It is the staff's belief that RD&D expenses can best be handled by allowing the program expenditure level set for test year 1985 to be continued for attrition years 1986 and 1987.

We note that while staff has expressed concerns over some specific programs and certain procedures, staff has clearly indicated its view that Edison's RD&D program is essentially well designed and directed. Staff further notes that the staff and the Commission do obtain annual reports of Edison's RD&D activities and thus an on-going review exists. Accordingly, we will adopt the staff recommendation and allow the 1985 level of expenditure to continue for 1986 and 1987. We will continue to allow Edison budgetary flexibility to shift funds among existing or new programs in RD&D during the rate case cycle subject to the directional language articulated in this decision and the guidelines adopted in D.82-12-005.

VIII. CONSERVATION AND LOAD MANAGEMENT

Edison originally requested a funding level of $71 million in program expenses for 1985. This amount was reduced to $62.7 million for reasons which include a desire by Edison to adhere to the Commission's "stay-the-course" funding policy. Staff recommended $57.8 million. Generally, the difference between Edison and staff is not due to any disagreement on the meaning of stay-the-course, but rather due to staff's recommended adjustments to specific programs.

Both staff's and Edison's program expenses include $3.1 million in the refrigerator rebate program, which has traditionally been funded and evaluated in Edison's annual offset proceeding. In addition to program expenses, Edison and staff are proposing capital expenditures of $4.2 million, and rate incentives for program participants of approximately $11 million.

We conclude that an expenditure level of $55.2 million in program expenses should be included in base rates for test year 1985. This figure reflects the adopted escalation factors and is included in the Results of Operations - Appendix D.

This level of expenditure includes $2.3 million for the Energy Efficient Refrigerator program which was previously funded in Edison's offset proceeding and $3.7 million for New Construction Programs, discussed under load management. Also, the adopted level of expenditure includes Edison's estimates for capital expenditures and rate incentives.

A. General Policy

The Commission's recent policy has been to maintain current authorized expenditure levels for conservation/load management programs rather than dramatically increase or decrease the authorizations from prior years. While some factors indicate that a less aggressive approach to conservation is appropriate, the

Commission had declined to dismantle the existing program infrastructure in the recognition that the energy scene may change quickly and dramatically. Beginning with PG&E's and SDG&E's test year 1984 general rate cases, the Commission had adopted a level of funding approximately equal to prior authorization levels. This has become known as the "stay-the-course" funding policy.

In particular, the Commission has articulated the following set of general guidelines in its recent test year rate case decisions for SDG&E (D.83-12-065), PG&E (D.83-12-068), and Pacific Power and Light Company (D.84-07-150):

- Maintain programs mandated or required by law.
- Review programs required by past Commission decisions to determine whether they should be continued.
- Implement only those new programs that are clearly cost-effective.
- Phase out/reject programs that require incentive payments borne by all ratepayers, but only cost-effective to participants and, because of potential for reduced billings, would probably be undertaken without incentives.
- Maintain/initiate programs which, although they may not meet some of the above objectives, are worthwhile based on considerations of equity and externalities.

In regard to the above guidelines we should note that the nonparticipant test should not be relied upon exclusively in the evaluation of resource additions, including load management and conservation programs. While we would not deny funding for any proposed programs based solely on their failure to meet the nonparticipant test, it is nevertheless an important factor in our decision to limit overall level of funding

Further, in regard to the Commission's "stay-the-course" policy and the question of the weight to be given the various tests, we note the testimony of staff policy witness Ahern:

> "We feel a 'stay the course' strategy applies to SCE. On the one hand, there are strong reasons for recommending a dismantling of SCE's conservation programs. The utility has excess generating capacity, fuel costs have moderated substantially, ratepayers are now paying for SONGS 2 and 3, the increased base rate level gives a much more accurate signal to ratepayers of the marginal cost of consuming added energy, and those not participating in conservation programs are more likely to be adversely affected now that average and marginal costs for SCE are close and likely to remain so through this decade.
>
> "On the other hand, much conservation savings are reliable and not subject to the uncertainties of fuel price increases and inflation. A number of programs can still make non-participants as well as all ratepayers as a group better off, by saving energy and capacity that would cost more to produce than the costs of the programs. Conservation programs also can be a better deal for the ratepayers than paying QFs full avoided cost for energy or paying for new utility generation projects. Funding a number of energy conservation programs can reduce the forecasts of SCE's long run avoided costs because, as demand is decreased or made to increase less than it would without the programs, SCE can back off generating from its most costly plants.

"It is important to put conservation programs on the same basis as supply programs. The Commission has before it five tests for judging the cost-effectiveness of SCE's conservation programs. These are discussed in Witness Danforth's exhibit. The tests are the societal test, utility test, participant tests, non-participant test, and all ratepayers test. Each test measures the costs and savings to each of these five groups. A conservation program obviously makes no sense if it fails even the participant's test. The utility test measures the costs and savings to SCE itself, while the broad societal test includes in it tax effects and 'external' costs and benefits to the U.S. of each conservation program. The all ratepayers test measures what all ratepayers as a group pay and save from the program. The key concept in this test is that the payment all ratepayers lose when a participant reduces his energy use is offset by the participant's own savings, so, for ratepayers as a group, the lost revenue from conservation is a transfer to the participant. The lost revenue and the participant's saving cancel each other out.

"The non-participant test treats the lost revenue as a loss to the non-participants, as they save nothing themselves in their own bills. If the system-average cost, which is the rate the participant saves by reducing his use a kilowatt hour, is 10¢/kwh, and if it is equal to the marginal cost of the utility, 10¢/kwh, then it is impossible for the non-participants to come out ahead if they pay anything for a conservation program, even 0.01¢. This is because the non-participants save 10¢, the reduced utility cost of producing the kwh, but they lose the 10¢ payment from the participant and they pay 0.01¢, for a net loss of 0.01¢. Only if the average cost or rate is below the marginal cost and if the conservation program costs less than the difference can the conservation program meet the non-participant test. As FIGURE 7 shows, with average and marginal costs now closer and likely to be close for years, conservation programs have a more difficult time performing well on the non-participant test.

"There is still plenty of room for disagreement on the weight to be given each of these five tests and on the appropriate role of utilities such as SCE in energy conservation. There are at least four different conceptual roles SCE might play in conservation, and each places a different weight on the cost-effectiveness tests.

"These are:

"1. Full Service Corporation. This role, promoted by the Energy Commission in prior biennial reports, sees SCE as a 'full service Corporation' that is in the business of providing energy services, such as light and cooling, rather than just literally providing kilowatt hours. This role would emphasize the societal test and the all ratepayers test. It encourages SCE to fund and

implement all programs that improve the comfort and efficiency of SCE's ratepayers in areas where they now use electricity. This is the maximum "interventionist" approach, which recognizes major market failures in California in inhibiting consumer investments in all cost-effective conservation measures.

"2. Conservation Same As Supply. This approach puts conservation literally on the same footing as supply projects, holding that SCE and its ratepayers as a group should fund and implement all conservation programs that can provide kilowatt hour savings at the same cost or less than can new utility generation projects and SCE purchases from QFs. This approach emphasizes the all ratepayers test. If SCE's avoided cost is 10¢/kwh, then any conservation program that costs all ratepayers less than 10¢/kwh should be implemented, because, if it is not, then the ratepayers unavoidably have to pay 10¢ anyway.

"3. Fairness Paramount. If SCE's role is to make sure no ratepayer group is disadvantaged by a conservation program, then emphasis is placed on the non-participant test. Programs that could benefit all ratepayers as a group are not implemented if some ratepayers pay more than they save.

"4. Free Market Approach. This approach relies on energy prices to encourage conservation by consumers and businesses. It holds that utilities should remain only in the monopoly electricity supply role and that other businesses should compete with the utility's prices by offering conservation measures. This approach emphasizes the

participant test, but only in that SCE should give ratepayers accurate information about current and future costs and prices, so consumers can make their own decisions about conservation and make their own calculations of the participants test.

"We favor treating conservation the same as supply projects and QF purchases, but tempered by needs for fairness. This means that all programs that pass even the non-participants test should be continued and perhaps even expanded. All programs that pass the all ratepayers test should be continued or started, but not if one grossly fails the non-participant test. To assure overall fairness, the entire conservation program as a package should meet the non-participant test, so those not involved in any SCE conservation program are not disadvantaged by the total expenditures. However, it is all right for some programs to fail the non-participants test.

"It is clear that there are still major impediments to consumers implementing conservation measures that can make all of SCE's ratepayers, and themselves, better off. SCE reports that businesses are reluctant to invest in conservation hardware that has a payback period greater than one to two years (SCE Exhibit 12, p. 1-7). This is with the generous tax credits and depreciation in place. Thus businesses seem to be short-sighted, and residential customers, particularly landlords, can move slowly to implement cost-effective conservation. Therefore there is a legitimate role for SCE to offer monetary incentives as

'sweeteners' to encourage conservation investments, especially investments in conservation hardware that can provide reliable savings over a long period. Having SCE's ratepayers actually pay cash to short-sighted businesses and property owners to encourage them to invest in measures that would save them money can seem unfair and abhorrent. But it makes economic sense for the ratepayers to pay for energy savings, because, in the absence of the cost-effective conservation savings, ratepayers will pay more than the cost of the conservation program for kilowatt hours provided by SCE or QFs.

"At present, any potential QF that can provide kilowatt hours at a cost less than SCE's short or long run avoided costs can sign a contract to do so and SCE is required to buy that energy. Conservation should be on the same yardstick, implemented if it passes the all ratepayers test. Ratepayers can be better off from conservation programs because such programs can have costs less than full avoided costs, so the benefits are shared between the ratepayers and the conservation program participant, while QFs receive the full avoided cost from the ratepayers." (Exhibit 58, p. VII-4.)

We note staff policy witness Ahern's testimony with regard to the nonparticipant test and the need to treat QFs and conservation programs on a comparable basis. Nevertheless, we will continue to give great weight to the issue of individual program cost-effectiveness and, at the same time, take all the factors discussed by witness Ahern into consideration.

1. Stay-the-Course Funding

We do not believe, however, as proposed by Edison in its brief (page 257), that the frame of reference for "stay-the-course" be limited to "total similar programs"--i.e., those that are proposed for funding in test year 1985 through base rates. Rather, since significant funding increases have occurred in offset proceedings, it is important to look at the sum total of all conservation and load management programs, regardless of the proceeding in which they are funded.

Our evaluation of Edison's and staff's funding recommendations in this case will follow the guidelines reiterated above, taking into explicit consideration the cost-effectiveness of specific programs. As a starting point, the following table presents a comparison of 1983 and 1984 funding authorizations (for rate case and offset proceedings), Edison's and staff's requested amounts in this proceeding and the amounts adopted.

TABLE 1
AUTHORIZED, RECOMMENDED AND ADOPTED FUNDING
FOR SCE TY 1985 CONSERVATION/LOAD MANAGEMENT
(IN THOUSANDS 1985 DOLLARS)

	DESCRIPTIONS	1983.0 AUTHORIZ.	1984.0 AUTHORIZ.	EDISON REQUEST 1]	STAFF RECOMMEND.	ADOPTED
	CONSERVATION PROGRAMS					
1	NONRESIDENTIAL					
2	Energy Audits (Over 500kw)	6975.5	6473.5	3588.0	3123.2	3588.0
3	Energy Audits (50-499kw)	1501.7	3077.0	7324.7	4727.8	6740.6
4	Energy Audits (Under 50kw)	1309.1	3684.5	703.6	1287.7	1287.7
5	Pump Tests	1125.7	1146.9	1593.6	1500.5	1593.6
6	Customer Incentives	6140.3	9140.3 2]	8415.5	11005.7	8415.5
7	Technical/Other	253.8	258.6	410.2	393.5	410.2
8	Outreach/Large Account Coord.			407.2	396.4	407.2
9	Other Rate Case Programs	980.0	998.4	0.0	0.0	0.0
10						
11	TOTAL—NONRESIDENTIAL:	18286.1	24779.2	22442.8	22442.8	22442.8
12						
13	RESIDENTIAL					
14	Residential Conserv. Srvce (RCS)	5500.0	5330.6 3]	6123.9	4170.1	4600.0
15	Multi-Family Audit Program (MFAP)	1098.7	1092.2 3]	1713.7	1713.7	1092.2
16	Conservation Workbook	156.3	263.9	335.5	335.5	263.9
17	Conservation Information	876.0	748.0	611.2	611.2	611.2
18	Wrap-Up	502.4	513.4	831.3	831.3	513.4
19	Refrig. Rebate (RCFP—offsets)	1884.8	2265.0 4]	3139.6 5]	3139.6	0.0
20	Solar Programs (Rate Case)	901.5	846.5	0.0	0.0	0.0
21	Solar OII-42 (Offsets)	1519.0	840.0 3]	374.7	374.7	374.7
22	Study & Evaluate Resid. Tech.	101.5	103.5	524.0	524.0	103.5
23	Customer Advisory Groups		8.9	77.2	77.2	8.9
24	Innovative Community Grants	268.3	115.0	231.9	231.2	115.0
24	Other Rate Case Programs	898.2	599.8	0.0	0.0	0.0
25						
26	SUBTOTAL:	13705.7	12726.8	13963.0	12008.5	7682.8
27						
28	Other RCFP Programs (Offset):	11900.0	22235.0 4]	22360.4 5]	22360.4 5]	25242.0
29						
30	SUBTOTAL—RESIDENTIAL	25605.7	35961.8	36323.4	34368.9	32924.8
31						
32	OTHER PROGRAMS					
33	Public Awareness	800.0	830.4	965.0	965.0	965.0
34	Advertising	800.0	800.0	1032.0	535.0	535.0
35	Measurement	2635.0	2717.2	3295.0	2717.0	2910.4
36	Mangemt/Admin/Reg Support	2512.4	1628.6	5316.4	3498.0	4000.0
37						
38	SUBTOTAL—OTHER	6767.4	5976.2	10608.4	7715.0	8410.4
39						
40	TOTAL—CONSERVATION PROGRAMS	50659.2	66717.2	69374.6	64526.7	63778.0

TABLE 1 (cont.)

DESCRIPTIONS	1983.0 AUTHORIZ.	1984.0 AUTHORIZ.	EDISON REQUEST 1]	STAFF RECOMMEND.	ADOPTED
LOAD MANAGEMENT PROGRAMS					
Residential A/C Cycling	2591.0	1682.0	3204.9	3204.9	3204.9
Agric. Load Management	927.0	683.0	318.8	318.8	318.8
Off-peak Cooling	258.0	863.0	497.0	497.0	497.0
Interrupt./Aux Gen/Energy Coop.	268.0	273.0	198.6	198.6	198.6
CIA A/C Cycling	810.0	608.0	1196.6	1196.6	1196.6
Swimming Pool Pump	577.0	583.0	1299.7	1299.7	1299.7
New Construction Programs			3702.5	3702.5	0.0
Test Programs	3376.0		2437.2	2437.2	2437.2
Experiments	4307.0	6676.0	1067.3	1067.3	1067.3
LM Information	1328.0	4337.0	1500.0	1500.0	1500.0
Regulatory Support	1084.0	1341.0	0.0	0.0	0.0
Optimizing Therm.		1099.0	250.0	250.0	250.0
SUBTOTAL—PROGRAM EXPENSES	15525.0	17545.0	15672.6	15672.6	11970.1
CAPITAL EXPENDITURES					
Residential A/C Cycling	1622.0	1622.0	3637.0	3637.0	3637.0
Agricultural Load Manage.			770.0	770.0	770.0
Interrupt./Energy Coop			230.0	230.0	230.0
CIA A/C Cycling	3589.0	3589.0	142.0	142.0	142.0
Test Programs			109.0	109.0	109.0
SUBTOTAL—CAPITAL EXPENSES	5211.0	5211.0	4888.0	4888.0	4888.0
INCENTIVES					
Residential A/C			4140.0	4140.0	4140.0
Agricultural Load Manage.			180.0	180.0	180.0
Off-Peak Cooling			560.0	560.0	560.0
Interruptible/Aux Gen/Energy Coop			5940.0	5940.0	5940.0
CIA A/C Cycling			510.0	510.0	510.0
Test Programs 8]			42.0	42.0	42.0
SUBTOTAL—INCENTIVES	3500.0	3500.0	11372.0	11372.0	11372.0
TOTAL—LOAD MANAGEMENT (WITHOUT INCENTIVES)	20737.0	22756.0	20560.6	20560.6	16858.1
TOTAL-LOAD MANAGEMENT (WITH INCENTIVES)	24237.0	26256.0	31932.6	31932.6	28230.1
TOTAL—CONSERVATION/LOAD MANAGEMENT (WITHOUT INCENTIVES)	71396.2	89473.2	89935.2	85067.3	80636.1
TOTAL—CONSERVATION/LOAD MANAGEMENT (WITH INCENTIVES)	74896.2	92973.2	101307.2	96439.3	92008.1

TABLE 1 (cont.)

FOOTNOTES

1] During the course of this proceeding, Edison stipulated to the Load Management funding levels recommended by staff.

2] Resolution E-31 authorized SCE to transfer $3,000,000 of its unspent 1983 carryover to C/I incentive conservation programs in 1984.

3] These funding levels were authorized in Decision 84-08-036.

4] Decisions 84-08-036 and 84-10-037 established an annual expenditure level for RCFP of approximately $25,242,000 in 1984 and 1985. SCE's request for refrigerator rebates was refrigerator rebates was $2,803,000. Since total funding authorized was approximately 80% of requested, 80% of 2503,000 was used as an estimate.

5] Again, these figures reflect the overall funding limit of $25,242,000 authorized in Decisions 84-08-036 and 84-10-037.

In the context of an overall "stay-the-course" policy, Edison's and staff's recommendations for test year 1985 can be described as follows:

- The overall funding level for nonresidential conservation programs is within past authorized levels. However, Edison does propose a significant shift in emphasis among the energy audit categories (i.e., relatively more funding for the 50-499 kW size users). Staff, on the other hand, recommends a significant shift away from audits in general to customer incentive programs.

- Edison's overall funding level request for residential conservation programs (including offset funding) is somewhat higher than the range of prior authorizations, primarily due to a significant increase in funding for the Residential Conservation Financing Program (RCFP) offset program authorized by D.84-08-036. Edison also requests a 15% increase in the Residential Conservation Service Program (RCS) and 57% increase in the Multifamily Audit Program (MFAP) in test year 1985 relative to the levels authorized for 1984. Other significant increases within the residential sector are in the Wrap-Up, Refrigerator Rebate, Study/Evaluation of Residential Technology and Innovative Community Grants programs. Staff's overall level of funding in the residential sector is lower due to their recommended reductions in RCS funding. On all other residential programs, staff agrees with Edison's proposals.

- Edison's request indicates significant (over 200%) funding increases for Management/Administration and Regulatory Support. It should be pointed out, however, that prior to 1985, the regulatory support component was incorporated into each individual program budget, making direct comparisons difficult.

- In the load management program area, both Edison and staff are requesting large increases in load management incentives, which are offset in part by decreases in program and capital expenditures. A primary factor in these increases is the recent order by the California Energy Commission (CEC) regarding Edison's air conditioning cycling programs.

- Edison (and staff) are also proposing funding of $3.7 million for a new construction demonstration program under load management.

On balance, Edison's requested funding levels are somewhat higher than previously authorized levels (i.e., $89.2 million compared to a range of $71.4-$89.5), particularly when the levels of incentive payments are accounted for (i.e., $100.6 million compared to a range of $74.9-$93.0 million). Staff's figures, on the other hand, appear more reasonable within the context of a stay-the-course funding policy.

However, both Edison and staff recommend specific program funding increases that, we believe, require closer examination--particularly in terms of their cost-effectiveness. Further, as indicated above, staff and Edison disagree on certain funding priorities, which need to be addressed. Our specific evaluation of these issues is presented below.

2. Program Cost-Effectiveness

While a "stay-the-course" policy can provide a general framework for evaluating the overall level of conservation and load management funding, it is the cost-effectiveness tests that guide this Commission as to the desirability of funding/expanding specific conservation and load management programs. This Commission has also articulated its policy to evaluate conservation programs on the same basis as supply programs. In a memorandum to all parties following the first en banc hearing, former President Grimes requested some means of evaluating resource options on a common basis. The use of cost-effectiveness tests, driven by marginal and avoided cost analysis provides such a yardstick.

There are five cost-effectiveness tests considered in this proceeding. Four of them--the participant, nonparticipant, utility and societal tests--are developed in the Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs developed jointly by the staffs of this Commission and the CEC. An additional test has been added called the all ratepayers test, which is essentially a combination of the participant and nonparticipant tests. The all ratepayers test resembles the societal test with tax credits not treated as transfer payments.

The results of the staff's and Edison's cost-effectiveness evaluations are set forth in Exhibit 94 at page 5-2. These tables indicate that:

- All nonresidential conservation programs, except for Commercial Wrap-Up (which is funded as pat of Commercial Incentives) are cost-effective to the nonparticipant.
- All residential conservation programs, except for RCS, RCFP, MFAP, Conservation Workbooks, Efficient Refrigerators and Residential Wrap-Up pass the nonparticipant test. According to these tables, all conservation programs pass all other tests, though the results for the MFAP are weak.

- All load management programs pass all the tests, though some (Nonresidential Air Conditioning Cycling) are more marginal than others. It should be noted, however, that staff did not evaluate the cost-effectiveness of the New Construction Programs, and Edison's evaluation in its workpapers indicates that three out of the four programs fail the nonparticipant test.

We have significant reservations about the methodologies and approaches used by both Edison and staff in developing these cost-effectiveness figures. Briefly, our concerns are as follows:

- None of the projected energy savings used in these calculations exclude energy savings which would have occurred in the absence of the program. This can substantially overstate a program's cost-effectiveness. Results from an RCS study suggest that, for that one program, 60% of the savings would have occurred in the absence of these programs (Exhibit 94, pp. 5-10).
- The results of Edison's own study of conservation potential and goals indicate a need to significantly curtail Edison's incentive programs, especially in the residential sector. While we agree with staff that parts of the model require further testing and refinement before implementing such a policy, we must be somewhat skeptical of funding proposals that move in the opposite direction.

- Edison has apparently treated nonresidential and residential conservation programs unevenly by excluding any attributable demand savings to residential programs, while including them for nonresidential programs. The demand savings are valued at the full cost of a gas turbine, which overstates the value during years of excess capacity.
- In evaluating the cost-effectiveness of certain conservation and load management programs, Edison and staff treated incentives as a transfer payment, thereby excluding those costs from the utility and societal tests. If incentives were treated as direct program expenses, the results of these tests would be significantly lower. The appropriateness of excluding these costs is still an issue.

We believe that staff's recommendations regarding measurement studies (see pp. 1-5 and 1-6 of Exhibit 94) will improve the cost-effectiveness information before us in future proceedings. In addition to adopting those recommendations, we direct staff and Edison to develop, for the next Edison general rate case:

- Information on the energy or demand savings of all conservation/load management programs net of savings that would have occurred in the absence of the program; and
- Cost-effectiveness analysis which includes value of service losses and value of system reliability levels in calculating the various cost-effectiveness tests, and which treat incentives as program costs, rather than transfer payments where appropriate.

With the above observations and policy guidelines in mind, we turn to a more detailed discussion of individual programs.

B. Commercial/Industrial/Agricultural Conservation

While staff and Edison agree on the total funding level for the Commercial/Industrial/Agricultural ("CIA") Conservation Program, staff recommends a shift of dollars from labor expenses to incentives. Staff recommends this reallocation from labor expenses

to incentives based on its assessment that (1) incentives are superior to audits in achieving conservation; (2) an equal percentage of energy savings should be achieved among Edison's commercial customers which can be accomplished by doubling the number of notices and the amount of incentives for commercial customers with demands less than 50 kW; and (3) a premium labor rate is paid to Edison's conservation employees. The table below sets forth Edison's request, staff's recommendation, and the level of expenditure adopted for

CIA Conservation Programs
(Thousands of 1985 dollars)

Program	Edison Request	Staff Recommended	Adopted
Energy Audits (Over 500 kW)	3,588.0	3,131.2	3,588.0
Energy Audits (50-499 KW)	7,324.7	4,727.8	6,740.6
RSVP Audits (under 50 kW)	703.6	1,287.7	1,287.7
Pump Tests	1,593.6	1,500.5	1,593.6
Customer Incentives	8,415.5	11,005.7	8,415.5
Technical/Other Support	410.2	393.5	410.2
Outreach/LB ACT Coordination	407.2	396.4	407.2
Total	22,442.8	22,442.8	22,442.8

It should be noted that the above figures reflect 1985 dollars developed using Edison's original escalation rates. The expenses shown in the Summary of Earnings Tables will reflect the adopted escalation rates.

1. Incentives

Staff strongly recommends expansion of incentives among commercial and industrial customers. This is based on the staff belief that the most persistent and reliable energy savings are from the installation of hardware items rather than audits.

Edison does not entirely agree with staff's recommendation. Edison believes that energy audits and incentives are actually complementary, not duplicative. Edison notes that the Commercial Energy Management Standards, adopted by CEC in response to the enactment in 1978 of Section 25406 of the Public Resources Code, direct the increased use of energy surveys to encourage customers to implement energy conservation measures. According to Edison this recognizes the importance of audits in reaching energy conservation goals.

Edison argues that in practice, auditors identify site-specific cost-effective measures based on the customer's specific operating characteristics. According to Edison, the incentives then help to motivate the customer to install the measures identified by the auditor. In addition, Edison argues that the installation of hardware devices alone do not ensure energy savings since many devices are subject to inefficient use by the customer.

On the other hand staff argues that many commercial and industrial customer might participate in incentive programs without the need for audits. According to staff, PG&E's results for 1983 in the non-residential area clearly support its position. Staff contends that PG&E has been more effective in placing conservation hardware because PG&E allows incentives for various types of hardware, without an audit, while Edison does not.

As articulated above, and in recent Commission decisions, we have certain basic reservations about expanding incentive programs. We recognize that incentive programs are very popular--and effective in "placing hardware." However, we are not convinced that they are designed well enough to reasonably insure ratepayers that the investment would not have been made anyway--without the incentive. Edison's audit procedures do help in that regard. Until we obtain additional information concerning the comparative cost-effectiveness of the two proposed approaches, we will authorize the lower level of customer incentives proposed by Edison. This level is consistent with prior funding periods.

With regard to the "Commercial Wrap-Up" program, however, we see no reason why commercial users would not purchase a $15-$20 water heater blanket on their own, once an auditor has recommended it for cost savings. While this program is very small in dollar amounts, it also benefits a very small number of commercial

users at the expense of nonparticipants. On the other hand, this program benefits small commercial customers, who are no different to residential customers in many respects and since these customers need "sweetners" as mentioned by policy witness Ahern--we will allow this program to be continued at its present level for the time being.

2. Equal Percentage Energy Savings

Staff contends that Edison must make a greater effort to achieve an equal percentage of energy savings among the various classes of commercial customer. This is based on a statement in D.93887 (dated December 30, 1981) that PG&E should target roughly comparable percentage savings in each of several classes of customers which staff believes should be applied to Edison.

Edison disagrees with staff's recommendation. Edison points out that the Commission had the opportunity but did not specifically adopt for Edison the same requirements it had for PG&E that a comparable percentage savings should be achieved among the customer classes. Instead, in D.82-12-055 (Edison's Test Year 1983 General Rate Case decision) the Commission granted Edison the discretion "to establish priorities and allocate funds to maintain a well-rounded program and to maximize energy savings." (Emphasis added). Moreover, Edison notes that in that decision the Commission further stated that "increases in program expenditures (should) be authorized at a rate which permits orderly implementation of the most cost-effective programs possible.

Edison argues that attempting to achieve the same percentage of energy savings among the various customer classes, as staff suggests, could dramatically alter the allocation of Edison's resources resulting in less efficiency overall.

We agree that staff has a valid concern based on equity for the small commercial customer and multifamily customer. However, we will not adopt the staff recommendation, as a matter of policy. On the other hand, our rejection of the staff recommendation does not mean that Edison should favor the large commercial and industrial customer at the expense of the others. We expect Edison to achieve the most cost effective energy savings possible but it must temper its program to avoid serious inequities among the classes.

Turning to the question of RSVP audits, staff recommends doubling the number of audits by mailing RSVP letters annually, rather than every other year as it is done currently. Staff expects this increase in mailings will double the requests for RSVP audits thus giving RSVP customers further opportunity to participate in Edison's rebate program.

The RSVP audit, described in Edison's Exhibit 12, page 1-6, is initiated by a mailing sent to each of Edison's 268,000 commercial and industrial customers with demand levels under 50 kW. The rate of mailing is regulated to match auditor workload and the mailing cycle is completed once every two years.

We certainly do not desire Edison to hire additional auditors for any reason. However, we see no reason why Edison cannot shift resources to audits for the smaller commercial customer. As noted, the allocation of resources is significantly skewed across energy audit categories. We adopt staff's funding proposal for RSVP audits by shifting program funds from the 50-499 kW user to the under 50 kW users.

Turning to the actual dollar amounts for the individual incentives, both Edison and staff recommend increasing hardware rebate incentives. We will adopt Edison's recommendation, since rather than doubling the incentive for a particular customer as

recommended by staff, Edison proposes to double the incentive based on the useful life of the hardware. Measures with a 7-12 year useful life would be eligible for a $0.02 per annual kWh saved while measures with over a 12-year useful life would receive $0.04 per kWh saved.

3. Premium Labor Rate

Staff recommends a reduction in labor costs for each category in the CIA conservation program, except in the RSVP audit category (demand less than 50 kW). This recommendation is based on staff's assessment that (1) labor saving devices (meaning the Computer Analysis Tool) will reduce the need for technical experts, and (2) premium labor rates are paid to Edison's conservation employees.

Staff notes that for 1985, Edison proposes to have two basic salary levels for its auditors, known as energy service representatives. For the entry level position Edison proposes to have a salary, exclusive of benefits and overheads, of $35,600. These auditors perform residential audits. The position requires a Bachelors degree in any subject (technical background not required), or equivalent, and to undergo three weeks of training (which will be reduced to two weeks when the federal requirements for the program lapse at the end of 1984.) Also, staff notes that for the more experienced auditor doing the commercial and industrial audits the salary level, again exclusive of benefits and overheads, is proposed to be $47,200 per year. Some additional training occurs during Edison employment but this higher level is filled from the entry level personnel.

While the above facts are not disputed, the testimony in the record on the salary issue is not conclusive in order to make meaningful comparisons between utilities. However, an entry level salary of $35,600 is excessive for the qualifications required. To put it simply, we fail to understand why Edison has to pay $35,600 per year to auditors whose duties include counting light fixtures in commercial establishments. On the other hand, we agree with Edison that the persons preparing the final recommendation for major capital projects, which could involve incentives of $40,000, for example, should have the necessary technical expertise. We also agree that machines cannot entirely replace people; however, we conclude that Edison's conservation department should trim its salary budget, and that Edison's entry level salaries should reflect the job market. Accordingly, we direct Edison to provide an affirmative showing, in its next general rate case, to establish that it's auditor salaries reflect the job market.

Further, because of our concern regarding Edison's extravagance, we direct Edison to freeze the number of auditors (energy service representatives) to end of year 1984 levels and not increase the number of auditors on its staff.

Also in its next general rate case proceeding, Edison will submit an exhibit to demonstrate that it has effectively reduced its conservation department salary budget from recorded 1984 levels. The exhibit will also include a numerical count of employees in the various job classifications in the conservation department, the salary range and qualifications for such classifications. Staff should submit such a data request to all utilities in future rate case proceedings so that meaningful comparisons can be made between utilities.

Edison is placed on notice that in its next general rate case proceeding it must make a convincing showing on the salary issue; otherwise, we will assess a penalty against Edison.

4. Conclusion

Edison and staff agree on the total of $22.4 million for CIA programs. We concur with this level of expenditure for 1985. While we see no need to set the expenditure level for each individual program, Edison is directed to modify its programs to double the number of RSVP audits by shifting among its audit programs. We expect an affirmative showing from Edison in its next general rate case to demonstrate the progress made toward this goal.

C. Residential Conservation

Residential Conservation
(Thousands of 1985 dollars)

Program	Edison Request	Staff Recommended	Adopted
Residential Conservation Service (RCS)	6,123.9	4,170.1	4,623.9**
Multi-Family Audit Program (CACS)	1,713.7	1,713.7	1,092.2*
Conservation Workbook	335.5	311.6	263.9*
Conservation Information	611.2	611.2	611.2***
Wrap Up	831.3	855.2	513.4*
Energy Efficient Refrigerator Marketing	3,139.6	3,139.6	2,265.0*
Solar Programs-Rate Case	0	0	0
Solar Rebate Demo. (OII-42)	374.7	374.7	374.7***
Study and Evaluate Res. Tech.	524.0	524.0	103.5*
Customer Advisory Groups	77.2	77.2	8.9*
Innovative Community Grants	231.9	231.9	115.0*
Total	13,963.0	12,009.2	9,971.7

Source of above Table - Exhibit 103A, Table V-6.
*Adopted "1984 authorized" level.
**Edison's request reduced by $1.5 million.
***Edison's request.

It should be noted that the above figures reflect 1985 dollars developed using Edison's original escalation rates. The expenses shown in the Summary of Earnings Tables will reflect the adopted escalation rates.

In summary, we have chosen to make our funding cuts to maintain a "stay-the-course" budget in the residential as opposed to the nonresidential sector for two reasons. First, these programs are less cost-effective than nonresidential programs both to all

ratepayers and nonparticipants. Second, funding of residential programs in offset proceedings has increased. We do not entirely eliminate programs failing the nonparticipants test for two reasons. First, as we have previously stated, the composite of all conservation and load management programs pass the nonparticipant test. Second, equity requires that programs continue to be made available to residential customers after the RCFP is completed.

Turning to the recommendations of staff and Edison, staff recommends a significant reduction in the level of funding requested by Edison for the RCS program, the first program listed above. Staff has no differences with Edison regarding the remainder. Staff's recommendation is based on the belief that by year end 1984 this program will no longer be mandated by law.

Edison argues that there is reason to believe the RCS program will be mandated through 1989.

However, even if RCS is no longer mandated, staff believes the program should continue at a lower budget level. Staff contends that the program can be made dramatically more cost-effective with a large number of audits conducted by telephone rather than in person and with the RCFP picking up many of the objectives of RCS.

In D.84-07-107 (PG&E) and D.84-08-036 (Edison), we expressed our views that the residential ZIP (zero interest loan program) and RCS should be temporary, and not institutionalized. Based on the evidence in this proceeding, we believe that Edison's RCS should be continued at reduced levels, along the lines recommended by staff, in test year 1985. In D.84-08-036, we authorized $5.3 million for test year 1984. Edison requested $6.1 million and staff recommends $4.2 million. We will reduce Edison's RCS request by $1.5 million to reflect a more gradual reduction in audit costs. Absent a mandate to the contrary, we conclude that Edison's RCS budget for 1986 and 1987 should taper down.

Accordingly, Edison should reduce its RCS budget by a further $1.0 million for each of the next two years.

Keeping in mind our stay-the-course policy, rather than reducing total conservation program funding, these dollars from RCS reductions should be shifted, as recommended by staff, to placing more hardware in the residential and small commercial and industrial classes. However, such a shift will be contingent on RCS not continuing to be mandatory in 1986 and 1987.

With regard to the future of the RCFP, including refrigerator rebates, our recent D.84-08-036 and D.84-10-037 have raised numerous issues concerning the cost-effectiveness and continued funding levels for these programs. We believe that these programs should continue to be evaluated in the annual offset proceedings until the issues have been addressed to our satisfaction. Hence, Edison's base rates will not include the refrigerator rebate program.

Turning to the MFAP, we will include this program in base rates at this time, but at a reduced funding level of $1,092.2, which is commensurate with our authorization for test year 1984 (D.84-08-036). As noted above, this program is only marginally cost-effective overall, and fails the nonparticipant test. We direct Commission staff and Edison to address the issue of terminating this program in Edison's next rate case proceedings.

We will authorize funding for the residential "Wrap-Up" and "Conservation Workbook" programs at the test year 1984 authorized levels in conformance with our "stay the course" policy.

Finally, we have been no evidence in the record that justifies the proposed increases to three other residential programs: Study and Evaluate Residential Technology, Customer Advisory Groups, and Innovative Community Grants. Accordingly, we will authorize funding at the test year 1984 authorized levels.

D. Load Management Programs

A description of the various programs is set forth in Edison's Exhibit 12 and staff Exhibit 96.

For reasons which include adhering to the Commission's stay-the-course policy, Edison stipulated to the funding levels recommended by staff. Also, Edison stipulated to the level of funding for the residential air conditioner cycling program and the optimizing thermostat program consistent with the mandate of the CEC in Order No. 84-0404-11.

The staff's recommended level of expenditures are set forth below:

Load Management Programs
(Thousands of 1985 dollars)

Program	Staff Recommended	Adopted
Residential A/C Cycling	3,204.9	3,204.9
Optimizing Therm	250.0	250.0
Demand Subscription Service	500.0	500.0
Swim Pool Pump Tripper	1,299.7	1,299.7
CIA A/C Cycling	1,196.6	1,196.6
Off-Peak Cooling	497.0	497.0
DSS-Low Users	294.6	294.6
TOU-Domestic	422.8	422.8
Swim Pool Load Control	0	0
DSS-CIA	804.5	804.5
Chiller Control	256.7	256.7
Computer Dispatch	158.6	158.6
Load Management Information	1,500.0	1,500.0
TOU-80	0	0
Interruptible/Aux Gen/ Energy Coop.	198.6	198.6
Agricultural Load Management	318.8	318.8
Experiments	1,067.3	1,067.3
New Construction	3,702.5	0
Total	15,672.6	11,970.1

As discussed above in Section A.2., we have certain reservations about the cost-effectiveness analysis presented by staff and Edison. Nonetheless, most of the load management programs are cost-effective based on their evaluations, given some degree of sensitivity analysis. We will adopt the staff's recommendation with

the exception of the New Construction Program. This new program offers builders and developers cash incentives, cooperative advertising and marketing expertise to encourage them to increase the energy efficiency of new structures with designs that exceed CEC Title 24 Building Standards. Approximately $2.3 million out of the $3.7 million in total funding is for cash incentives.

Only Edison provided some cost-effectiveness analysis on this program, and limited at that. Edison's result indicates that three out of the four program elements fail the nonparticipant test. Unlike other programs, neither staff nor Edison performed sensitivity analysis on the input assumptions. Although the CEC has recommended that we fund new construction programs, we do not believe that a new program of this type and magnitude is consistent with our stay-the-course policy and funding guidelines. This program will not be authorized for this rate case cycle. We recognize that the CEC is working towards higher energy efficiency building standards and we support their efforts in this area.

Although Edison and the staff did not have any overall budget or program differences there are a few items concerning load management programs which should be noted.

E. Order of CEC

Concurrent with the processing of this general rate case application, the CEC held workshops and hearings in their Docket No. 82-LMR-1, concerning the load management programs of Edison. The purpose of the CEC proceeding was to facilitate implementation of CEC load management standards, principally addressing residential air-conditioning cycling, demand subscription service, and related programs. Edison, the staff, the CEC staff, and other parties participated in the CEC proceeding.

On April 17, 1984 the CEC adopted Order No. 84-0404-11. That order was transmitted to all parties to the Edison rate case and official notice of the order was granted on June 18, 1984.

Among other things this order directed Edison to continue its residential air conditioning cycler program at a rate of 24,000 units per year for 1985 and 1986. This number does not represent the recommendation of the staff (15,000) nor that of Edison (40,000).

With the exception of the size of the cycling program the staff generally found itself in agreement with the order's program goals. Also, as a matter of policy the staff recommends that this Commission adopt the same programs at the same levels as set forth in the CEC order.

The CEC order, of which official notice is taken by this Commission, was not the final word on this subject. Edison filed a petition for reconsideration of two issues. First, Edison objected to the CEC's decrease in incentive levels for the cycler program which Edison felt would impair the ability to obtain volunteers for the program. Second, the order mandated a 2 kW average load drop for each program cycler. Edison felt that while the specified load drop was appropriate as a goal, it was too high to mandate and the program was still cost-effective with a lesser achieved load drop. (Petition for Reconsideration, May 23, 1984.)

Edison's petition was granted on June 20, 1984, further hearings were held and a new order modifying Order 84-0404-11 was issued on August 1, 1984. This did not change the number of cyclers but did increase the average incentive level to that currently in use and set the 2 kW load drop as a goal and not a mandate. In addition the new order required Edison to submit to the CEC by January 31, 1985 a plan to evaluate certain load management goals set forth in the order including a real time pricing study.

The revisions to the previously ordered cycler program do not impact the staff and Edison budget recommendations with respect to either capital or expense items because incentives are revenue transfers between non-participants and participants. The staff previously analyzed this program assuming that incentives would be at the level they have been in the past (and the level the new order has restored them to) and it is the staff opinion that the program is still cost-effective at the new incentive level. We direct both staff and Edison to continue evaluating this program, and to address the considerations we have raised in Section A.2. above.

Finally, we take official notice of CEC Order 84-0404-11 and note that funding to implement the programs recommended in the order is included in the budget adopted in this opinion for Edison's Conservation and Load Management Programs.

F. Other Programs

We will now turn to the differences between Edison and staff related to the programs which provide support for the Conservation/Load Management plan.

The following table sets forth the levels of expenditure requested by Edison, the staff recommendation, and the adopted amounts.

Other Programs
(Thousands of 1985 dollars)

Program	Edison Request	Staff Recommended	Adopted
Public Awareness	965.0	965.0	965.0
Advertising	1,032.9	535.0	535.0
Measurement	3,294.9	2,717.2	2,910.4
Management/Admin/ Reg/Support	5,316.4	3,498.0	4,000.0
Total	10,609.2	7,715.2	8,410.4

It should be noted that the above figures reflect 1985 dollars developed using Edison's original escalation rates. The expenses shown in the Summary of Earnings Tables will reflect the adopted escalation rates.

1. Advertising

Staff recommends reducing Edison's estimated advertising budget from $1,033,000 to $535,000. The reduction is based on staff's evaluation of the recorded advertising expenditure in 1983 ($484,000) when compared to the authorized amount ($800,000) for the same year.

Edison argues that in 1983 its advertising was shifted to assist in implementing other programs, such as the Residential Conservation Financing Program which is funded through the CIMAC, an offset clause. Consequently, the cost of general advertising funded through base rates was reduced. In 1984, Edison expects to effectively spend the entire authorized amount for advertising.

Edison further argues that in addition, several trends support the level of funding requested by Edison for advertising. First is the decline in media attention paid to energy issues and particularly energy conservation. According to Edison, this trend will likely continue. With this decline in energy-related publicity, Edison believes that companies like itself must play a larger role in educating and reminding their customers about the long and short-term benefits of conservation and load management. In this way, Edison contends, the commitment to energy savings can be maintained.

Edison believes that utility-sponsored advertising is necessary because customer confusion exists from companies promoting conservation hardware or products. According to Edison this material is often inapplicable in specific portions of its service area. Attitudinal surveys performed by Edison and provided to staff indicate that customers have more confidence in utility-sponsored conservation information campaigns than they have in information coming from other sources.

We conclude that general advertising costs should be kept to a minimum especially since many of Edison's programs provide for their own promotion. Accordingly for 1985, we will adopt the staff recommendation of $535,000.

2. Measurement

Staff Exhibit 94 discusses the measurement and cost effectiveness of Edison's conservation programs. Details of expenditure levels are set forth at page 6-2. Edison requests $3.3 million, staff recommends $2.7 million. For the reasons set forth below, we conclude that an expenditure level of $2.9 million for 1985 is reasonable. As discussed in Section A.1 above, we also adopt staff's and our own recommendations for improving measurement and cost-benefit analysis.

a. Energy Services Reporting System

Edison requested $255,700 for the Energy Services System. Staff recommends $156,000 derived by escalating the expenditures recorded in 1983 and adding $50,000 to allow for increased reporting requirements suggested by staff. Edison notes that the level of funding requested for 1985 is $18,700 less than the amount budgeted in 1984 by Edison.

Edison states that during 1983, the company upgraded its data base and put on-line its reporting system known as the Conservation Reporting System - "CRS-II" which is designed to eliminate manual processing of audit results. In 1985, Edison expects further enhancements to make the system more responsive to users' needs, including the incorporation of "peg counts"; a peg count counts the total of each type of conservation device installed.

While adopting the enhancements required by staff, we conclude that Edison's request is reasonable.

b. SIC Coding

Edison requested $407,900 for SIC coding mandated by the CEC. Staff recommends $307,500 which is the amount recorded in 1983 for this project. Edison argues that this amount is insufficient to meet this mandate.

In 1985, Edison plans on bringing this project in-house rather than using a contractor which charges for each customer coded. Edison agrees that initially the cost of this project will be slightly higher when done in-house. However, Edison argues that since the contractor's price per customer increased in 1983 and may continue to increase in future years, it will be more productive to continue this project with Edison personnel. According to Edison this will protect the company and the ratepayers from further increases in the rates charged by outside contractors.

We conclude that it is reasonable to bring this project in house. Accordingly, we will adopt Edison's estimate.

c. Remaining Measurement Issues

The staff funding recommendation differs from Edison on two remaining measurement categories -- Attitude Surveys and Quality Assurance Overheads. (Exhibit 94, pg. 6-2).

Edison agrees that for the Attitude Survey Program, it can adjust to the $260,200 level recommended by staff. Edison also agrees with staff that $336,000 requested for Quality Assurance Overhead is no longer necessary. On this basis, Edison's total request of $3,294,000 for the measurement program should be reduced by $384,200. Accordingly we conclude that a reasonable level of expenditure for the 1985 Measurements Program is $2,910,400.

3. Management/Administration Regulatory Support

In D.82-12-055, the the Commission directed Edison to consolidate its regulatory support activities into the Management/Administration/Regulatory support category for Edison's next general rate case. Edison states that these activities are necessary to sustain program effectiveness, achieve objectives of management, address policy direction provided by regulatory agencies, and ensure that conservation and load management programs meet the needs of Edison's consumers.

In 1983, the regulatory support component was incorporated into each individual program budget, whereas for 1985, these costs are consolidated for presentation.

Edison requested $5,316,000 for this category, staff recommends reducing this amount to $3,498,000, which staff believes is the level of expenditures recorded in 1983. The staff recommendation amounts to a 34% reduction.

Edison argues that staff has increased Edison's reporting requirements since 1983. Also, Edison argues that since it is not beyond dispute that staff has fully segregated 1983 expenses to determine the total for this category, some increase over the amount recommended by staff is warranted. We conclude that Edison has a valid point. Accordingly, we will adopt an expense level of $4.0 million which amounts to nearly a 15 percent increase over the amount recommended by staff.

G. Other Conservation/Load Management Issues

1. Management Flexibility

In D.82-12-055, Edison was granted the discretion to reallocate up to $2,500,000 within the Residential Conservation, CIA Conservation, and Load Management categories. The Commission granted this discretion to PG&E and SDG&E as well. This discretion allows the utility to respond when circumstances change so that the most effective programs can be maintained. Staff has no quarrel with the dollar amount but has other concerns regarding this flexibility.

Staff recommends that in cases where Edison is directed to install a certain number of devices that number should not be exceeded in the year for which the authorization is given. (Ex. 96 at 11-3, § 16.) The staff feels very strongly that this recommendation apply to the air conditioner cycler program. Specifically, staff refers to the last general rate case decision and Edison's reliance on its discretionary budget authority to dramatically increase the number of devices allowed in the residential cycling program. (Ex. 130 at 3.) Staff believes that such major restructuring of programs should only be done "with the Commission's knowledge and approval."

Edison states that D. 82-12-055 authorized the company to install 20,000 residential cyclers and 45,000 commercial and industrial cyclers over the 1983-84 period. During the marketing phase, it became obvious that residential customers were more receptive to air-conditioner cycling than C/I customers. Edison argues that since the residential air-conditioner cycling program was also more cost-effective, Edison shifted 37,000 cyclers from the C/I program to the residential program resulting in 57,000 residential cyclers and 8,000 C/I cyclers. The overall total number of CPUC authorized cyclers was not changed. Edison contends that without the flexibility to reallocate funds, the company would not have achieved this more cost-effective result. Apparently Edison did not bother to notify the staff in writing regarding the shift. Whatever the facts are concerning this lack of communication, Edison is unable to point to any written communication which notified staff in advance of this change in plan.

We are surprised that staff was not made aware that the substitution discussed above was about to occur. Regardless of whether staff members were informed of these matters by telephone and other oral communications, Edison has a responsibility to memorialize important shifts in program emphasis in writing. We are aware that Edison is required to submit several conservation and load management reports each year to the Commission, but this is after the fact and does not relieve Edison of the responsibility to keep staff informed on an ongoing basis. Accordingly, Edison should remind its managers that they do have a responsibility to inform staff in writing, even if it is a matter of confirming a telephone or oral discussion, before making important changes in program emphasis. It is not sufficient for Edison, after the fact, to merely include such information in its reports.

Finally, we expect Edison to implement our decisions today with regard to shifts in program emphasis (i.e., RSVP audits) and limiting/eliminating funding for certain programs. These decisions are not to be circumvented via discretionary funding reallocations.

With this understanding, we will not adopt the staff recommendation since we believe the utility must have flexibility to expeditiously change direction when necessary because we hold the utility responsible for achieving the most cost-effective program. We will certainly reduce this flexibility if Edison does not improve its efforts to keep staff up-to-date on all major changes.

In addition to the $2.5 million flexibility within categories, Edison seeks authorization from the Commission to redirect up to $1 million between categories so long as the total level of funding for conservation/load management programs is not exceeded. The categories are: CIA, Residential, Load Management, Public Awareness, Advertising, Measurement and Management/ Administrative/Regulatory Support.

For example, Edison argues that it could exceed the authorized level for the CIA Conservation category by as much as $1 million if another category were underspent by the same amount. According to Edison, in the appropriate circumstances, allowing this additional discretion could reduce potential carryover amounts and allow more effective utilization of the overall conservation/load management resources.

We have reservations about granting the degree of flexibility that Edison requests. We will continue our current policy of requiring advice letter filings for shifts among the three major program categories of CIA, Residential Conservation, and Load Management (per D.82-12-055) or shifts of greater than $2.5 million within program categories.

2. Three-year Rate Case Cycle

During the course of this proceeding, the Commission moved Edison from a two-year rate case cycle to a three-year cycle. The parties were directed to discuss the effect of this change on Edison's Conservation and Load Management programs.

Edison states that it does not expect to make any significant program modifications nor does it anticipate terminating any programs during the three-year funding period. While at the time this opinion is being prepared there is some uncertainty surrounding the future of the RCS program, Edison supports an on-going residential audit activity, "even if all federal and state residential audit requirements are eliminated." Moreover, Edison notes legislation may mandate the continuation of RCS through 1990. For these reasons, Edison believes that the level of funding authorized for the test year for Conservation Load Management Programs adjusted by the adopted attrition mechanism is the appropriate level of funding for the attrition years.

In addition, Edison notes that there are current reporting mechanisms and procedures which allow the Commission to monitor the expenditures for these programs while preserving management flexibility so that the most effective operation of the company's programs can be maintained. These mechanisms are:

1. Conservation/Load Management Plan (December/Report) - the December 1 Report addresses Edison's conservation/load management activities planned for the coming year, including estimated program costs and energy savings. The report must be filed by December 1 in non-rate case decision years (D.86501). Edison has 60 days after a general rate case decision in which to file the report (D.93637).

2. Conservation/Load Management Program Results (March 31 Report) - The March 31 Report addresses Edison's conservation/load management activities for the preceding year, including program costs and energy savings. The report must be filed by March 31 during nonrate case years. During rate case years this report must be filed by Feburary 15.

3. Conservation/Load Management Expenditures and Proposed Budget (February 15) - Pursuant to D.82-12-055, Edison must report on its conservation/load management expenditures during the prior year and its proposed budget for the current year by February 15. Any carryover amounts and rate base, expense, and load management incentive components must be clearly shown.

4. Advice Letter Filing (March 1) - In accordance with D.82-12-055 if at the end of any year, Edison has underspent base rate funds authorized for conservation/load management programs, the company must seek Commission approval

of its proposed allocation through an advice letter filing provided the amount of the allocation is greater than $2.5 million or if Edison plans to reallocate funds among the three major program categories of Residential Conservation, CIA, and Load Management. The Advice Letter must be filed no later than March 1.

Edison believes that with these mechanisms in place, the Commission can be assured that the funds authorized for Conservation/Load Management programs in the test year will continue to be spent for Conservation/Load Management Programs in the first and second attrition years. These mechanisms also allow management the flexibility previously granted by the Commission to adjust the programs in response to changed circumstances. In addition, Edison believes, these mechanisms will ensure that the Commission is properly informed of any change in the programs that affect the authorized allocation of funds. Therefore, Edison submits that further reports or procedures are unnecessary.

Staff does not have any particular concerns with respect to maturing rate case conservation programs; however, staff notes that programs which are not included in the rate case can be addressed in the appropriate proceeding related to such programs, the RCFP.

With respect to load management, however, staff argues that a very different situation exists. According to staff, many of the programs involving significant funding levels are those where continuation or funding level beyond the first attrition year (1986)

is very much in question. Staff contends that many of the programs are very much in an evolutionary stage; some are still, in the staff's view at a RD&D stage. These would include the several load management programs subject to CEC mandates such as residential air conditioner cycling, which CEC specifically indicated in its order, is a two-year program. Staff is very concerned that these programs not exceed the current number of units and budget without a sufficiently comprehensive review to gauge their success and value.

Additionally, staff recommends that Edison include in its 1987 attrition year filing the appropriate funding levels for its Air Conditioner Cycling and Demand Subscription Service load management programs as well as any other load management programs which the CEC may order for implementation by Edison in 1987.

We appreciate staff's concerns but are not prepared to schedule separate hearings on Edison's 1987 Load Management Programs.

However, Edison should keep staff informed in writing of all new CEC mandates effecting its programs and provide staff with a preliminary 1987 Load Management program 30 days before it submits its 1987 attrition filing. We realize that the 1987 attrition filing will be made a few months prior to the December 1 1986 report; however, the purpose of the preliminary report is to allow staff the opportunity to work with Edison to finalize the 1987 program before it is presented in the December 1 report. Edison's 1987 attrition filing will not be accepted until Edison provides staff with all details related to its 1987 Load Management program. 1987 Load Management programs will reflect the same level of expenditure authorized for 1985 with an adjustment for attrition, which is to be considered in a separate proceeding. The number of units to be installed in 1987 will not exceed CEC mandates.

IX. RESOURCE PLANNING

A. Overview

Staff believes Edison is generally designing its resource plan and programs consistent with the policies of this Commission and the California Energy Commission (CEC). Staff notes that for the future Edison's decisions about its resources will have to be driven by a number of factors. These include building those resources which will cost less than its own forecast of long-run avoided costs. Staff points out that certain types of resources will be needed by Edison to maintain a dispatch flexibility that other sources, such as qualifying facilities (QFs) may not provide. The approval of the Balsam Meadow project is such an example. Finally, staff believes that unless new types of price offers are developed to make QFs interested in supplying intermediate and peak service to meet Edison's actual load characteristics, intermediate and peak generation facilities will likely remain exclusively Edison facilities.

Staff further notes that while Edison is entering a period when it has a great diversity of resources, a large amount of its total resources are tied to the potential uncertainties of nuclear power. These uncertainties include the future status of SONGS 1, the delays on the Palo Verde Nuclear Generating Plant, and whatever uncertainties that may hover over operating plants such as SONGS 2 and 3. Therefore, staff believes that reserve margins higher than long-range goals may be appropriate during periods of uncertainty. In addition, staff agrees that Edison's retirement policies for its oil and gas fueled generating plants should reflect these concerns as well.

We generally concur with staff's assessment of Edison's current resource situation and agree that in view of the potential uncertainties of Edison's nuclear resources, it may be prudent, for

the short-term at least, to maintain reserve margins somewhat higher than would normally be appropriate; however, the economics of such insurance still remain to be evaluated. We are not convinced that Edison requires reserve margins of over 22% for the next three years. These reserve margins appear large in view of the California Energy Commissions recommended reserve margin level of 14%.

B. Reserve Margin Requirement

The subject of reserve margins arose in this proceeding in two contexts. First, Edison undertook a new reserve margin study in connection with the Fall 1983 resource plan to evaluate what their reserve margin requirements should be in the future. This study was influential in determining the direction Edison's retirement plans should go. Second, the staff proposed the adoption of a "reliability adjustment factor" (RAF) for adjusting the value of capacity payments to QFs. (See chapter on Marginal Cost.) The RAF adjustment is highly dependent on the reserve margin.

Edison presented testimony with respect to its target reserve margin through 1993. The following chart, reproduced from the company's testimony, illustrates Edison's estimate of the minimum reserve levels needed through 1993 to provide acceptable service reliability to the company's customers, together with a planned reserve margin included in the current Future Generation Resource Program.

As illustrated in the chart, Edison's long-term target reserve margin is 18 percent, plus or minus 2 percent. The near term target ranges from 20 percent to 25 percent. Edison notes that planned reserve margins will meet or exceed the minimum level each year from 1985 through 1993; also, target and forecast reserve margins in the 1985-1993 period are very nearly equal.

Southern California Edison Company

RESOURCE PLAN RESERVE REQUIREMENTS

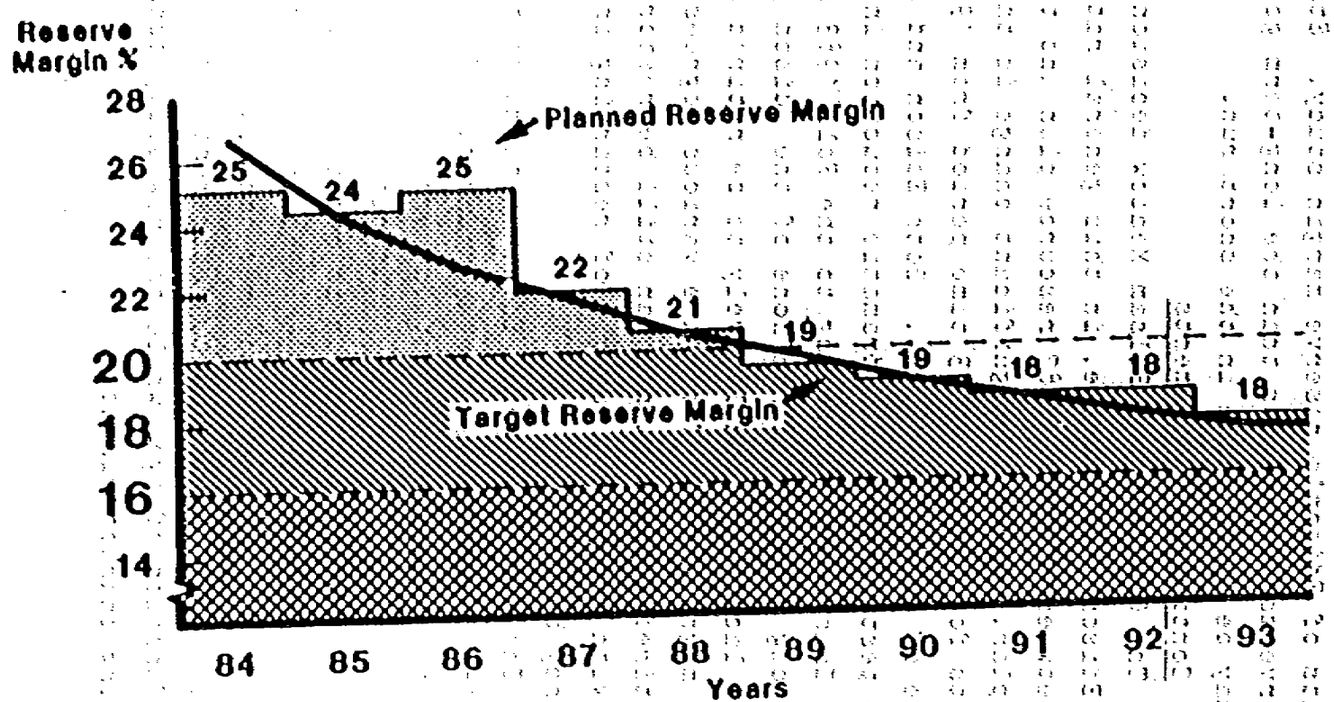


CHART 4

Southern California Edison SCE

Staff does not have reason at this time to disagree with the results of Edison's reserve margin study. Staff acknowledges that reserve margins higher than the long-term goal of 16 to 20 percent may be appropriate in the short run.

C. Contingent Retirements

The Commission's Balsam Meadow decision (D.83-10-031) required Edison to summarize, in this general rate case, the key changes between the Fall 1982 resource plan and the Fall 1983 resource plan. The most significant change is the reduction in retirements for the 1983-1993 time period from 1992 MW to 1080 MW, a net change of more than 800 MW. Both Edison and staff provided extensive testimony on this dramatic reduction in retirements.

In summary, according to the Fall 1983 resource plan, other than the Long Beach 1 plant, none of the Edison plants which have retirement labels are conclusively to be retired as the normal use of that term might imply. There are various degrees of retirement. While "retired", these plants can still be restored to some manner of service, with some units capable of restarting in five to ten days on an emergency basis.

The manner in which Edison determined the priority for retiring its plants is set forth in Exhibit 57. All oil and gas fueled units other than combustion turbines, were analyzed with respect to several criteria. A numerical ranking resulted and Edison's retirement priority is as set in that list. Staff notes that this report, prepared in conjunction with the Fall 1983 resource plan, was the first time Edison had done such a comprehensive retirement study. In the past, retirement strategy was apparently solely a function of age, while the new study considers a wide range of operating characteristics.

While staff does not take exception to Edison's planned retirement, staff complains about "intolerable" difficulties in obtaining the information needed to evaluate the retirement plan.

We will now address this matter.

D. Data Requirements

Staff requests that Edison forward its Fall, 1984 resource plan, with complete workpaper support, to the staff within 10 days of its completion. Staff contends that Edison's response was incomplete and not timely.

While agreeing that there is a need to provide timely and useful information to the staff and noting that in non-rate case years, the staff's principle interest is in the capital investments included in the resource plan, Edison recommends that only capital investment information relative to the Fall, 1984 resource plan be submitted to the staff within thirty days of completion, with the remainder of the resource plan workpapers to be submitted upon specific request, thereby minimizing the transmittal of voluminous material which may not be pertinent to staff's areas of investigation.

Staff points out that the resource plan is utilized for a great many purposes at the Commission, including the development of marginal costs and related analyses. According to staff, it had considerable difficulty in obtaining a clear idea as to the resource assumptions that Edison used in developing its marginal costs. This hindered the staff analysis. Therefore, staff wants to receive all information necessary to support the resource plan. Essentially this means the workpapers, studies, and other materials that explain not only what is in the resource plan but the decisional process by which Edison arrived at its conclusions. According to staff, there was a lack of explanation of alternatives considered and the decision process.

Staff argues that since the request for information relative to the Fall 1984 Resource Plan will not be in the context of a formal proceeding, the staff may well experience even greater difficulties in obtaining its requested information since the urgency associated with the completion of a formal proceeding under the rate case plan would not exist.

As we see it, the problem is largely due to lack of communication. Edison has a valid concern regarding the proliferation of paper and on the other hand staff certainly has a need to be informed of the decisional process related to the resource plan. We are confident the problem can be solved, if in the future, whenever a new resource plan is adopted Edison promptly provides staff with an oral briefing. Hopefully, this approach will cut down on the proliferation of paper. We will hold Edison responsible for initiating these sessions in rate case years and nonrate case years. Following submission by Edison of information related to capital investments within 30 days of completion of the resource plan and following the oral briefing, staff should submit data requests for whatever additional information it needs. With this understanding, we will adopt Edison's recommendation regarding workpapers for the Fall 1984 resource plan. This procedure will apply to all future Edison resource plans until further notice.

E. Studies to be Undertaken

Staff recommends that two studies be undertaken: (1) a joint study by the Commission and the CEC on system reliability and reserve margins for use in resource planning and QF pricing; and (2) an economic study to determine the relative costs and benefits of both 14 percent and 18 percent reserve margins. The staff witness testified that it would be preferable for the utilities to coordinate their efforts to provide a statewide study on these

subjects for consideration by this Commission. Edison recommends that should the Commission determine that either of these studies is required, that they be undertaken as a single coordinated study, performed by the utilities for submission to both Commissions.

The evidence in this proceeding contains an assortment of positions as to what the optimal or appropriate level of system reliability is for Edison. In the California Energy Commission's 1983 Biennial Report, Edison's long-run (1994) reserve margin requirement was estimated at 14% (California Energy Commission. Securing California's Energy Future. pg. 103). On the other hand, Edison's long-run target reserve margin is 18% ± 2%. Furthermore, in the short-run for the years 1985-1987 Edison's target reserve margins are 24%, 22%, and 22% respectively. It is not clear that Edison needs such seemingly large reserve margins. However, based on the record before us, we are unable to determine a reasonable level of reserve margins or system reliability which should be used for resource planning and QF pricing. We are concerned that Edison may have some excess capacity in the short-term.

We conclude that both studies be undertaken in order to determine the appropriate levels of system reliability for California utilities to be used for resource planning and QF pricing. While the second study may be more Edison specific, we see no reason why the two studies should not be undertaken on a statewide basis for both Commissions. Accordingly, our Executive Director should arrange for joint workshop sessions with CEC and the California utilities. (These could be along the lines of OII 89.)

We note that PG&E, in formulating its Energy Reliability Index, relies upon Expected Unserved Energy (EUE) and Loss of Load Probability (LOLP) criteria rather than the simpler reserve margin measurement. The workshops and studies should consider these other reliability criteria, with the aim of producing recommendations of consistent reliability criteria to be used on a statewide basis for the spectrum of resource planning, conservation and load management evaluation, and QF pricing purposes.

F. Conclusion

For purposes of this proceeding, we will adopt Edison's resource plan as set forth in Exhibit 20, including the level of planned contingent retirements and planned reserve margins. However the economics of carrying excess reserve margins needs to be evaluated and the studies mentioned previously should be undertaken.

X. COGENERATION AND SMALL POWER PRODUCTION

A. Progress and Goals

Staff concludes that Edison's progress "tracks reasonably well the progress expected by the CPUC."

The staff view of Edison's efforts in promoting cogeneration and small power production has changed dramatically since the Test Year 1983 general rate case. At that time the staff recommended a series of rate of return penalties.

Edison states that it is committed to the continuing development of alternative and renewable resources as part of its resource strategy. As shown below, Edison estimates that the total capacity on-line in 1985 is 1100 MW.

Third Party CoGeneration and Small Power Production Capacity Commitments and Capacity On-Line

Item	Committed Annual Total	Committed Cumulative Total	Cumulative Total On-Line
Recorded			
Prior Years	254	254	140
1982	703	957	205
Projected			
1983	643	1,600	350
1984	350	1,950	750
1985	350	2,300	1,100

Edison's goal for capacity from renewable and alternative resources is much greater, projecting 3394 MW in service by 1993, as reflected in the following table:

1993 Goal For Total Operational Capacity From Renewable And Alternative Resources

1984-1993 Ten-Year Window	
Firm Effective Dedicated Capacity	2188 MW
Wind Diversity Capacity	600
Capacity Serving Own Load, Nameplate	218
Subtotal	3006
In Service Prior to Summer 1983	
Firm Effective Dedicated Capacity	260 MW
Wind Diversity Capacity	18
Capacity Serving Own Load, Nameplate	110
Subtotal	388
Total In Service By Summer 1993	3394 MW

By year-end 1984, Edison expects to have a total commitment of 2241 MW of capacity including the addition of the Balsam Meadow Project (200 MW) and the Coolwater Coal Gasification Plant (100 MW). This is aproximately 66 percent of the overall goal of 3394 MW set for 1993.

However, Edison cautions that there are a number of obstacles which may affect the pace at which cogeneration and small power production is developed. According to Edison the most significant obstacle is the difficulty in obtaining siting and permit approvals, especially from the SCAQMD. Other obstacles include the scheduled expiration of the federal energy tax credits in 1985, the lower avoided cost payment rates and uncertainty among developers regarding the long-run standard offer.

Edison submits that the marketing effort to encourage new projects will need to be increased due to these obstacles. More important is the Commission's continued commitment to support and encourage developers through the series of hurdles required to bring a project on-line. In any event, Edison argues that the presence of these obstacles reinforces the need to maintain a vigorous program to support the development of renewable and alternative resources.

We reiterate our long-term commitment to support and encourage developers to bring on-line as many new projects as is feasible. However, we recognize that the extent of cogeneration and small power production ultimately available is one of the great unknowns in the long range energy picture. Tremendous uncertainties over what the "winner" technologies will be for the future, the level of avoided costs, what tax incentives may exist and a number of other economic and regulatory factors will all influence the development of cogeneration and small power.

In addition, there remain many questions concerning the ability of cogeneration and small power to meet the various resource mix needs which Edison or any other utility requires. For example, current pricing schedules for cogeneration and small power production do not differentiate which hours during a peak period the energy or capacity is provided, yet a utility's own needs would indicate such a differential might be appropriate.

Over the next several years many of these issues will be resolved and the relationship between QF production and utility's resource needs will become clearer.

However, in the meantime we conclude that Edison's progress thus far is reasonable and we expect Edison to vigorously pursue its goals.

B. Other Issues

As previously discussed in connection with resource planning and load-management, staff had difficulty reconciling Edison's (MW) numbers related to cancelled and committed projects. We need not discuss all the details but it certainly does seem that much confusion and irritation can be avoided if Edison's managers initiate oral presentations to supplement their annual reports. We expect Edison and staff to resolve their communication problems and we see no need for the Commission to order further reporting requirements at this time. We expect an aggressive effort by Edison in the whole area of utility/staff communications. According to staff there are two other items which should be noted.

First, the staff wishes to bring to the Commission's attention the fact that the Edison cogeneration and small power production program may experience transmission constraints at some time in the fairly immediate future. According to staff the problem is not imminent but must be watched carefully.

Second, although the staff initially indicated its suport for Edison's full test year 1985 budget request for cogeneration and small power programs, the Results of Operations analysis led staff to recommend a reduction on the basis that Edison did not spend the level of funding authorized for 1983.

Edison estimates the cost of the cogeneration and small power production program in 1985 to be $2,813,000. Staff relying on 1983 recorded data (plus incremental changes estimated by the company for 1984 and 1985) recommended a reduction in labor expenses of $150,000 and non-labor expenses of $692,000, for a total reduction of $842,000.

Edison argues that for labor expenses, it is inappropriate to rely on 1983 recorded data to evaluate the estimated labor expenses for 1985. During 1983, Edison increased its professional staff for this program by six. However, two members were added in April, one in August, and three in December. Therefore, according to Edison, expenditures in 1983 do not reflect the full-year costs for the additional six authorized staff members. Edison developed its estimated labor expenses for 1985 based on the assumption that the labor expenses associated with an increase in personnel would occur for the entire 12 months in 1985.

For non-labor expenses, the proposed reduction would reduce the amount for co-funded engineering and feasibility studies and related front-end technical assistance for potential projects by about 80 percent, from $878,000 to $186,000. Edison suggests that if the staff-recommended reductions are adopted the Commission may be unintentionally sending a strong negative signal with respect to the development of cogeneration and small power production.

Edison notes that its program includes contracting, outreach and communication, and technical assistance. The program provides developers with the option to select standard offers approved by the Commission. Some developers may seek non-standard terms because of unique circumstances. In the appropriate cases, when desired by a developer, Edison may negotiate nonstandard agreements consistent with evolving Commission guidelines and prudent business judgment.

According to Edison the outreach and communication elements of the program serve to identify potential projects and inform potential developers of available forms of assistance offered by

Edison. The types of technical assistance offered to developers include a confidential financial analysis program, interconnection guidelines, jointly funded feasibility studies, engineering studies and design, and the identification of the applicable regulatory and environmental permit processes.

Largely because of the results achieved by Edison since the 1983 rate case, we will adopt the level of expenditure for 1985 requested by Edison.

XI. MARGINAL COSTS

A. Introduction

"Marginal cost" is an economic concept which refers to the change in total costs resulting from a change in output. As applied to an electric utility, marginal cost is the change in costs resulting from a change in the number of kilowatts (kw) of capacity and kilowatt-hours (kWh) of energy produced.

Since 1981, this Commission has used marginal, as opposed to embedded, costs in ratemaking to allocate the revenue requirement between customer classes, to guide the design of specific rates, and to measure the cost-effectiveness of conservation and load management programs. We have consistently viewed marginal costs as resulting in rates which provide the most appropriate price signal to consumers and which in turn promote conservation and efficiency.

While we have agreed on the use of marginal costs in ratesetting, the components of marginal costs to be used in ratesetting and the methodologies for calculating those components have undergone continued scrutiny and refinement. In this decision, we will again examine the three principal components of a utility's marginal cost--energy, demand, and customer costs. We will consider the appropriate methodology for calculating these costs and the extent to which each of these components are to be included in the final marginal cost calculation.

Related to marginal costs is the concept of avoided costs. Avoided costs are essentially those costs of electric generation which the utility avoids by purchasing the power from another source. This Commission, in implementing the Public Utilities Regulatory Policies Act of 1978, has used the utilities' avoided costs as the basis for the prices to be paid by utilities for power purchased from cogenerators and small power producers (qualifying facilities or QFs). The appropriate methodology for calculating a

utility's avoided energy and capacity costs related to QF payments has been included as an issue in general rate cases and will be considered in this decision.

Before commencing our discussion of marginal and avoided costs, we wish to first address the comments and testimony of two parties to this proceeding who recommend that the Commission abandon its marginal cost approach in favor of using embedded costs. In the opinion of the California Manufacturers Association (CMA), the volatility in forecasting such marginal energy cost inputs as fuel prices warrants a return to the accuracy achieved by embedded cost ratemaking. With respect to calculating marginal demand costs, CMA similarly argues that "...rather than using cost estimates derived from a generation reliability-oriented, proxy-based calculation in ratemaking, the Commission should base rates on [Edison's] actual cost of service in the Test Year." (CMA Opening Brief, at p. 7.)

General Motors and Union Carbide Corporations (GM/Union Carbide) also assert that the utility's actual or embedded cost is the most appropriate basis for revenue allocation and rate design. In the absence of viable embedded cost proposals in this proceeding, however, GM/Union Carbide chose in their opening brief to address those proposals which GM/Union Carbide acknowledges were formulated in accordance with the Commission's present policies favoring marginal cost-based revenue allocation/rate design methods. (GM/Union Carbide Opening Brief, at p. 2.)

In their reply brief, however, GM/Union Carbide criticize a perceived discrepancy in the treatment of ratepayers and qualifying facilities in the development of marginal costs. Citing the staff's opening brief, GM/Union Carbide argue that staff has asserted that the calculation of a precise demand cost figure is an important consideration only with respect to the payments to be made by a utility to QFs. GM/Union Carbide believe that, in contrast, for rate

design purposes staff has taken the cavalier position that close adherence to cost is unimportant since that process is already subject to adjustments that collectively diminish cost considerations.

We acknowledge that there are uncertainties inherent in any kind of forecasting. In this decision, as in every rate case decision, however, it is our intention to carefully scrutinize the record to ensure that only the most appropriate assumptions and methodologies are adopted to calculate Edison's marginal costs. Our reliance on marginal costs for revenue allocation and other ratemaking purposes has spanned many years and, for Edison, commenced with the utility's 1981 test year rate case (D.92549). In that decision and those major rate case decisions which have followed, we have restated our policy of using marginal, as opposed to embedded, costs in ratemaking and have thoroughly explained our reasons for doing so. We refer CMA and GM/Union Carbide to those decisions.

We also wish to reiterate the view expressed during the en banc hearings in this proceeding by past Commission President Grimes- established Commission policies will be altered only for good reason. Marginal cost remains an important factor for determining adopted cost recovery by customer group. Avoided cost pricing has been adopted by this Commission and dictated by the federal government for use in developing payments to qualifying facilities. Although the methodologies for calculating marginal and avoided costs are often complex, over the years we have and will continue to refine and improve those methodologies to provide the most accurate cost signals and alternative generation pricing. In achieving that accuracy, we intend to treat ratepayers, qualifying facilities, and the utility alike with fairness and impartiality. Marginal and avoided costs will therefore remain the basis for revenue allocation, rate design, conservation and load management considerations, and qualifying facility payments.

B. Economic Time-Frame

In evaluating a utility's marginal or avoided costs, the Commission must first choose the economic time frame within which those costs will be viewed. Specifically, the Commission must decide whether to adopt "short-run" or "long-run" marginal or avoided costs. As applied to electric utility marginal costs, these terms do not refer to a particular period of real time, but rather the flexibility which the utility has with respect to adjusting utility plant or its operation in response to a change in output. The "short-run" refers to a situation in which the utility's plant remains constant, but the operation of that plant can be varied. In the "long-run," all aspects of the economic equation can be changed, including fixed assets (utility plant) and all variable inputs.

With respect to the appropriate economic time-frame for marginal energy costs, the staff in its brief correctly states current Commission policy:

> "There is no doubt that the marginal energy cost calculation method is short term by its nature. It examines the operation of the existing Edison resource system under conditions assumed to be reflective of the test year period in question. This is consistent with recent Commission decisions including the prior Edison general rate case, the recent Pacific Gas and Electric Company (PG&E) general rate case and D.92749 in OII 67, the generic marginal cost proceeding. (See, e.g., D.82-12-055 at 199-200 (1982), D.83-12-068 at 337.)" (Staff Brief at p. 53.)

In combination with short-run marginal energy costs, we have consistently concluded in prior general rate cases that the marginal costs of demand or capacity should also be based on the short-run situation. In D.93887, we stated:

> "Disagreements regarding the computation of long-run marginal capacity costs need not be resolved in this proceeding because we believe short-run energy plus short-run capacity costs should be used in setting rates; we want to show the consumer the present cost of his consumption."

In that decision (PG&E's 1981 general rate case), we adopted the following equation for marginal costs: MC = Marginal Operating Costs + Shortage Costs. In the absence of a methodology to calculate directly a utility's shortage costs, in D.93887 we adopted PG&E's recommendation of indirectly calculating those costs by creating a proxy to measure the costs. The measure would approximate what a customer would have to pay to avoid a shortage by assuming that the least cost to consumers would be the least capital-intensive addition to capacity to avoid the shortage. The adopted proxy was a combustion turbine. As the combustion turbine served as only a proxy for the calculation of a shortage cost, it was not necessary for the turbine to be a part of the utility's resource plan. The adoption of a short-run marginal cost approach therefore made the utility's resource plan irrelevant with respect to calculating those costs.

We have continued to apply the foregoing principles in both ratemaking proceedings and in proceedings to establish short-run avoided cost payments to QFs. The only variation to this approach has been our adoption in PG&E's 1983 general rate case of an adjustment mechanism known as the Energy Reliability Index or ERI. This mechanism serves to adjust the value represented by a combustion turbine to reflect the actual situation faced by PG&E in maintaining reliable service. (D.83-12-068, at pp. 343-349.)

It is our intention in this proceeding to continue to base our marginal cost ratemaking and QF pricing on the short-run economic time-frame. With or without an adjustment of the shortage cost, the combustion turbine will remain a proxy for that cost without any need to assess whether or not Edison will construct such turbines in order to meet its resource requirements in the foreseeable future.

Any discussion or adoption of a long-run approach to the calculation of marginal or avoided costs must await future rate case proceedings. We have only recently embarked on an analysis of potential long-run marginal and avoided cost methodologies as part of our proceedings relating to QF pricing. Specifically, Applications (A.) 82-04-44, 82-04-46, and 82-04-47 are the requests of the three major California electric utilities for approval of a Standard Offer No. 4. This offer will serve as the basis for a purchase power contract between a QF and the utility based on long-run avoided costs. This proceeding is being heard in two phases. The express purpose of Phase I, which has been recently submitted, was to examine various proposals for the calculation of long-run avoided costs related to QF payments.

It should be noted that the Commission did adopt an interim Standard Offer No. 4. This standard offer, however, was developed through a negotiating conference and its adopted methodology has not been scrutinized in the hearing process. Further, portions of the offer were recently suspended.

Under these circumstances, we believe that it is premature to alter our course of relying on short-run marginal costs for ratemaking and QF pricing purposes. Following our analysis of the record in A.82-04-44, et al., we will be in a better position to determine the propriety of applying the resulting methodology to ratemaking. Until that time, however, short-run marginal and avoided costs will serve as the most appropriate cost indicator in setting utility rates and the most appropriate basis for pricing under QF Standard Offers Nos. 1, 2, and 3.

C. Adoption Of A Uniform Methodology

As stated previously, marginal costs are used by the Commission in ratemaking proceedings for rate design, QF pricing, conservation, and load management purposes. The staff suggests that

ultimately the long-run avoided cost methodology being developed in A.82-04-44, et al. will provide a common yardstick by which all resource and rate design decisions are made and compared. While we believe that the consideration of a long-run methodology is currently reserved to A.82-04-44, we have stated our current intention to uniformly apply short-run marginal energy and capacity costs for all ratemaking purposes.

We also see no reason for varying the short-run marginal cost methodology depending on the purpose for which it is being used. By applying the same short-run marginal cost methodology for all purposes for which such costs are currently used, we will ensure an equivalent treatment of the utility, its customers, and qualifying facilities. A single methodology should also enhance comprehension of the approach which we adopt.

D. Marginal Cost Components

The following discussion will address the parties' positions and the Commission's conclusions regarding each of the marginal cost components considered in this proceeding. Although we have mentioned the distinction between marginal cost and avoided cost, our examination of the components of marginal cost will include any related discussion of avoided cost. Further, additional issues, such as the use of a statewide production simulation computer model, will be discussed within the context of the component impacted by the recommendation.

1. Marginal Energy Costs

a. Edison's Position

Edison first presented its methodology for determining marginal and avoided energy costs in Exhibit 9. This exhibit, however, was later supplemented by Exhibit 9(A) in which Edison proposed an alternative approach for determining QF energy prices.

In Exhibit 9, Edison defines marginal energy costs as the change in total costs resulting from operating changes made in response to load changes. Edison states that these costs consist of incremental fuel and variable operations and maintenance (O&M) expenses. In Edison's view the inclusion of a flat variable O&M component is consistent with Edison's present method of calculating its avoided cost of energy. Edison believes that no evidence was presented justifying inclusion of either variable Administrative and General (A&G) or variable working cash expenses in calculations of either its marginal or avoided cost of energy. With respect to A&G expenses, Edison includes this entire component in the capacity cost calculation since A&G does not vary with the change in kWh. Edison believes that to include a variable A&G component in the energy cost calculation under these circumstances would be tantamount to double counting.

In estimating marginal energy costs for test year 1985, Edison used a production cost simulation computer model called PROMOD. Edison began its estimation process by performing a production cost simulation for a "base-case" loads and resources forecast. From that point, Edison used three different methods for calculating marginal energy costs--one for all off-peak hours, a second for summer on- and mid-peak hours, and a third for winter on- and mid-peak hours.

For the off-peak calculation, Edison extracted from its "base-case" loads and resource forecast an average of the hourly marginal costs during off-peak periods for each season. This number was then divided by the cost of Edison's primary incremental fuel (gas) to derive an incremental energy rate (IER). This IER was then multiplied by the forecast price of gas and increased by the variable O&M component cost to derive the off-peak marginal operating cost at the generation level.

For the summer on- and mid-peak periods, Edison used a procedure called the "zero-intercept" method. This method required Edison to first estimate its total fuel requirements for a base-case loads and resource forecast. The base-case load forecast was both increased and decreased by various increments for all hours in each mid-peak and on-peak costing period in order to determine the impact on total oil and gas usage. Using this data, Edison estimated a curve which showed how marginal oil and gas requirements vary with increases and decreases in load in each costing period. The "zero intercept" of this curve indicates the level of marginal heat rates at the base-case level of load in the test year. These marginal heat rates were then multiplied by the forecast price of the incremental fuel and increased by the variable O&M cost component to derive the mid-peak and on-peak marginal operating costs at the generation level.

For winter on- and mid-peak periods, a different approach was taken in response to deficiencies in the way the PROMOD model handled certain system operating conditions occurring only in the winter season. Specifically, Edison based its estimated mid-peak and on-peak winter incremental heat rates on an analysis of historical data as well as on information from the PROMOD simulation of the summer season.

Neither Edison's opening brief nor its reply brief addresses any of the issues related to the marginal energy cost discussion in Exhibit 9. Instead, these briefs focus on Exhibit 9(A) entitled "Alternative Proposal for Determination of Energy-Payment Prices for Purchases From QFs."

In Exhibit 9, Edison had originally proposed that its avoided cost of energy, on which QF payments would be based, would be the same as its marginal cost of energy. The incremental energy rates for 1985 and 1986 for use in the QF payment calculation would thus be identical to the incremental energy rates used in calculating Edison's marginal energy costs.

In Exhibit 9(a), Edison departed from this approach and proposed an alternative methodology for calculating QF energy payments. Edison asserts that its general rate case is the proper forum for proposing changes to the calculation of IERs used in QF energy payments. Exhibit 9(A) explains both the Edison's proposal as well as Edison's reasons for recommending a methodology for QFs different from that used for determining Edison's marginal energy costs:

> "Because of the complex nature of production cost simulation models used in the current method, QFs have had difficulty understanding how prices have been determined and how they might change in the future. Decision No. 82-12-120 stated that 'QFs must be able to understand how prices are being determined to make intelligent investment decisions.' Further, the Commission report on the Long-Term Standard Offer emphasized that QFs need a price that is certain, accurate, and verifiable. Consequently, an alternative approach for estimating heat rate values or IERs, using methods which are more straightforward for purposes of pricing QF energy and which are fair to both QFs and ratepayers, has been developed and is being proposed as follows.
>
> "Edison proposes that recorded oil/gas system heat rates, appropriately time differentiated, will be used to develop QF energy prices. The price will be adjusted to reflect periods when non-oil/gas energy is on the margin.
>
> "The heat rates and adjustments for periods when non-oil/gas energy is on the margin will be updated annually in Edison's ECAC filing for a June 1 Revision Date. Following approval by the Commission, they will be used with current fuel costs to develop each of the regular quarterly postings of avoided energy prices for QF purchases until subsequently revised by the Commission.

"This proposal has advantages over the current method in that it:

"1. Involves simpler and more understandable calculations.

"2. Uses verifiable recorded data to determine oil/gas heat rates.

"3. Uses verifiable recorded data with current oil/gas prices to value non-oil/gas marginal energy." (Exhibit 9(A), at p. 2.)

Some of the specifics of Edison's proposal include a recommended two-year average heat rate "in order to smooth out, to a degree, the effects of any radical changes due to unusually good or poor hydro conditions and the effects of other major changes, such as placing new generation units into operation." (Exhibit 9(A), at p. 3.) Edison also proposes to include in its IER calculation the value of marginal non-oil/gas energy that Edison would purchase at the recorded average price of energy rejected during Edison's recorded minimum load periods. A two-year average again is proposed to lessen the effects of possible wide year-to-year variations. Edison's sample calculation, however, was based on only 12 months of data related to rejected energy prices due to the only recent practice of keeping such records.

It is Edison's opinion that there are no disadvantages to using recorded as opposed to forecasted data to calculate QF energy payments. Edison notes that its alternative proposal will capture the actual changes in generation resources as they occur in contrast to reflecting the forecast changes on a speculative basis. Further, the changes from one test year to another are not significant enough to justify concern in terms of lag on a recorded basis since the calculation of Edison's incremental energy rates are largely influenced by the average IERs of its marginal oil/gas-fired units which do not change significantly from

one year to another. Additionally, Edison believes that the certainty offered by its pricing approach will help to maintain ratepayer indifference, a goal in QF avoided cost pricing.

In further support of Exhibit 9(A) Edison also cites three problems associated with computer models. The first relates to the extensive data associated with using such complex models. Edison described the second and third problem areas as follows:

> "... Second, due to differences in the algorithms embedded in different production simulation computer models, no two models give the same results. Third, and perhaps most important, some amount of forcing of the algorithm as well as the data becomes necessary to obtain reasonable results from these computer programs." (Edison Opening Brief, p. 308.)

These statements appear to reflect Edison's support for developing IERs without production cost simulation models. Edison does not suggest, however, that its model PROMOD be abandoned in calculating IERs used in the development of its marginal energy costs.

Further, although Edison emphasizes the need for simplification and verifiability in these calculations, Edison rejects staff's recommendation that the Commission initiate an OII to consider developing a statewide production simulation computer model. Edison argues that use of such a model would not be productive for the following reasons:

> "The model would become extremely complex to capture the individual characteristics of each system; The model would do little to simplify the validation of the incremental energy rate calculation; The state of the art of the production simulation modeling has not advanced far enough to capture all the intricacies of

a power system independent of the modeler's influence. The modeler's influence becomes a necessary part of the process to produce reasonable results which reflect the system. Thus, adopting a standard complex model will not automatically assure that the results will be reasonable nor that two modelers will achieve comparable results. Therefore, Staff's proposal for a statewide production model should be rejected." (Edison Opening Brief, at p. 313 (emphasis original).)

b. Staff's Position

In the staff's view, marginal energy cost is comprised of marginal running costs which reflect the costs of running the generation system (principally fuel costs) plus variable operation and maintenance (O&M) costs, variable administrative and general (A&G) costs, and variable working cash. As noted previously, Edison's calculation of marginal energy cost does not include variable A&G costs or variable working cash.

Staff, like Edison, used a production cost model to calculate the marginal running costs. Using a model called IAm, staff calculated the incremental cost of every unit on an hourly basis with a probability analysis as to what was the marginal unit. The staff added 500 BTU's/kwhr for all time periods to account for differences between the simulation and expected operation. Staff notes that, unlike Edison, it did not vary its approach between off-, mid-, and on-peak periods.

Staff asserts that Edison needed to differ its approach by season and time period since PROMOD had been basically designed for purposes other than marginal energy cost calculations and did not handle such simulations as start-up costs and minimum load situations. Further Edison had determined that the model did not react properly to small variations in demand changes, using 800 megawatt changes instead.

Except for differences in models and certain key resource assumptions, staff states that it and Edison used basically identical input assumptions in running their respective models. The key resource differences related to the San Onofre Nuclear Generating Station Unit I (SONGS I) and the Palo Verde Nuclear Generating Station Unit I (PVNGS I), both of which Edison included. The staff performed a series of runs which alternately included and excluded these plants.

According to the staff the appropriate resource mix is that which exists when the test year begins, January 1, 1985. The staff points out that PVNGS I is currently not scheduled to begin full power operation until March 1986, while this Commission is in the best position to forecast whether SONGS 1 will be operating in 1985.

The staff believes that its methodology for developing marginal running costs is technically valid and results in a reasonable series of values. The approach is consistent with that utilized in prior general rate case proceedings and has been adopted by the Commission. Staff believes, however, that it will be necessary to update the forecasts of the appropriate fuel costs and other significant inputs such as purchased power transactions, assumptions and forecasted demand by adopted TOU periods.

In contrast, staff finds Edison's PROMOD approach is flawed due to errors in various calculations performed by Edison, the need for large as opposed to marginal or incremental changes to measure the effectiveness of the simulation, the use of different approaches for different time and seasonal periods (e.g., summer and winter mid- and on-peak), and the absence of any reflection in the mid-peak summer-winter historical comparison of new nuclear generation such as SONGS 2 and 3.

With respect to QF energy payments, the staff's proposal is to utilize the marginal energy cost figures developed with the production cost model with some adjustments to reflect

Commission policy. No separate proposal like Edison's Exhibit 9(A) is therefore suggested for QF energy payments. The staff methodology for QF energy payments relies on the marginal running cost and includes variable operation and maintenance costs and variable working cash. Unlike the marginal cost calculations, it does not include variable administrative and general expenses. This approach, according to the staff, is premised entirely on the procedure established in the recent P&GE general rate case decision.

In its brief, the staff states that it is currently unwilling to endorse the Edison's alternative approach for QF energy pricing. In rejecting Edison's proposal, staff reasons that the purpose of the avoided energy cost calculation is to establish a payment to QFs corresponding to the costs the utility would have incurred if it had produced the energy itself. Staff notes that Edison's alternative approach relies entirely on recorded data for Edison generating units operating during the historical period used for the calculation. Edison proposes to use a two-year period, which for test year 1985 would require 1983 and 1984 recorded data.

The staff argues, however, that the Edison generation resource situation for test year 1985 will be considerably different than it was for 1983 and 1984. The resource differences would include the fact that neither SONGS 1 nor SONGS 3 operated in 1983. SONGS 2 ran in part of 1983, and SONGS 1 is not likely to run in 1984. All three however, are proposed to operate in 1985. Finally, a number of relatively inefficient oil and gas fueled generating units which did run in 1983 and 1984 are currently scheduled for retirement (cold standby) in 1985 and 1986.

Staff acknowledges that there are inherent limitations to forecasts. However, the issue in question is the determination of incremental energy rates for the Edison system for test year 1985. The staff believes that using recorded data that excludes Edison's nuclear plants that will be operating and includes inefficient oil and gas plants that likely will not be operating

presents a greater problem. Staff therefore concludes that the judgments that will go into the computer simulation will be more reflective of the period of concern than the recorded information relied upon in Edison's alternative.

In its reply brief, staff also responded to Edison's claim that "due to the differences in the algorithms embedded in different production simulation computer models, no two models give the same results." While this fact is not contained in the exhibits or transcripts of this proceeding, the staff believes that the driving algorithms or formulas utilized in both the Edison PROMOD model and staff IAm model are the same, both being Booth-Balereaux algorithms. Therefore, any differences which exist between Edison and staff's production simulations are due to differences in the way the models handle purchased power, hydro, and start-up conditions.

Because of its simplicity and verifiability, the staff understands the QF's support for Edison's alternative. Staff also notes that such an approach is worthy of consideration and evaluation. The staff is concerned, however, that, while it has no evidence of a bias, the approach might result in higher energy payments than the production model would produce since it would lag behind resource changes that should improve Edison's cost situation. Staff believes that the approach, distributed just days before the hearings commenced with no independent staff analysis, has not been properly evaluated. Under these circumstances, staff would recommend that the use of a production cost model be continued in this proceeding. Any further examination of the approach should, however, be undertaken in a more comprehensive manner in a proceeding specifically related to QF pricing, such as Order Instituting Rulemaking No. 2 (OIR 2).

To promulgate QF understanding of energy payments and further the goal of uniformity between utility computer models, the staff proposes that the Commission initiate a formal proceeding

for the purpose of determining the appropriate computer model or models to be used by all electric utilities. In addition the staff recommends that procedures be established to ensure intervenors have access to the model.

Finally, related to computer data, the staff states that it experienced difficulty in obtaining in a timely manner the computer analyses which supported Edison's marginal cost exhibit. The staff recommends that in the future utilities be required to provide the computer input and output data files which support their exhibits concurrent with the filing of the application.

c. Interested Parties' Positions

A number of interested parties provided testimony or briefs on the issue of the calculation of Edison's marginal energy cost. These parties included Federal Paper Board Company, Inc. (Federal), the California Manufacturers Association (CMA), Occidental Geothermal, Inc., and Ultrasystems, Incorporated (Occidental/Ultrasystems), and the Independent Energy Producers Association (IEP). Of greatest concern to all of these parties is the calculation, either by computer model or Edison's alternative approach, of the incremental energy rate (IER).

(1) Computer Model Approach

With respect to IERs developed through the use of computer models, Occidental/Ultrasystems assert that the IER calculation of neither the staff nor Edison is reasonable. Occidental/Ultrasystems contend that in developing their IERs staff and Edison used out-of-date assumptions regarding peak demand. These parties also argue that staff and Edison made unrealistic estimates of the incremental fuel cost. In their opinion, the use of these estimates will artificially lower the derived incremental energy rate.

On their first point, Occidental/Ultrasystems cite the testimony of both their own witness and Edison's witnesses. The parties state that the peak demand assumptions used by PROMOD to derive IERs are lower than the peak demand figures in Edison's

resource plan. The effect of understating peak demand is to improperly depress the IER. Occidental/Ultrasystems therefore recommend that the production simulation models must be rerun with the updated peak demand levels reflected in Edison's resource plan in order to properly determine a short term projection of incremental energy rates.

On their second point, Occidental/Ultrasystems note that both Edison and staff used an estimate of $5.80/mmbtu for 1985 for the cost of incremental fuel in estimating marginal energy costs and the resulting IERs. According to the witness sponsored by these parties, overestimates of the incremental fuel cost relative to the costs of non-oil/gas resources will result in a lower derived IER than should be the case. The current incremental fuel cost in the Edison service area is $4.62/mmbtu on non-episode days and $5.67/mmbtu on episode days. Assuming 82 twenty-four hour episode days per year, the weighted average incremental fuel cost is $4.86/mmbtu. If this price escalated at a 6 percent annual rate for six months, the resultant weighted average incremental fuel cost would be $5.01/mmbtu, 14 percent lower than the figure used by staff or Edison.

In light of the current fossil fuel market, Occidental/Ultrasystems argue that it is unreasonable to assume the magnitude of increase assumed by staff and Edison in the next six months to one year. Occidental/Ultrasystems therefore recommend that the marginal energy costs and resultant derived incremental energy rates be recalculated using their more reasonable estimate of fuel costs ($5.01/mmbtu).

Other parties commenting on the computer development of incremental energy rates included Federal, CMA, and IEP. While Federal endorses the use of Edison's alternative approach for QF energy pricing (see discussion infra), if computer simulation models are used to develop avoided energy costs, Federal supports the recommendations of Occidental/Ultrasystems with one modification. This modification relates to the estimate of Edison's fuel cost.

Specifically, Federal notes that the current indexed GN-5 rate of approximately $4.62/mmbtu does not reflect the higher rate paid by Edison during episode days. According to Federal, the Commission's June 7, 1984 decision on Southern California Gas' CAM established an episode day rate of $5.67/mmbtu and a non-episode day rate of $4.62/mmbtu. The average of these two rates, which Edison will pay and cogenerators will ultimately receive in their avoided energy cost rate, must by definition be less than $5.80/mmbtu. Since it is impossible to state with certainty what rate Edison will actually pay, because it will be the sum of the episode and non-episode day rate, Federal urges that the rate applied by Edison be based on the average gas price paid by Edison during the prior quarter. Alternatively, Federal suggests that the rate be based upon the average GN-5 rate forecast by Southern California Gas Company for the most recent CAM proceeding based on its estimate of the number of episode days.

Federal supports staff's proposal to include a working cash allowance in the avoided energy cost calculation. According to Federal, fluctuations in electricity output can affect working cash needs. Further, inclusion of working cash expenses has been approved by the Commission for both the PG&E and SDG&E systems. In Federal's opinion, no basis has been shown for rejecting staff's proposal or for distinguishing the Commission's decisions in these other proceedings.

Edison's fuel cost estimate of $5.80/mmbtu was also considered excessive by CMA. According to CMA, the inaccuracy of this estimate is easily documented by reference to Edison's current tariffs and its proposed energy payments schedules for power purchase from qualifying cogenerators and small power producers for the period August 1, 1984 through October 31, 1984. CMA notes that if it were shown that Edison's gas rates were likely to increase significantly in test year 1985, use of a fuel cost figure in excess

of current prices would, of course, be appropriate for marginal energy cost calculation. In CMA's opinion, however, the record provides no support for such an assumption. CMA also argues that rates based on a marginal energy cost calculation which reflects only Edison's episode day fuel price will not send accurate conservation price signals. Thus, calculating Edison's marginal energy cost for the test year using only its episode day gas price is comparable to calculating its marginal demand cost using only its summer peak generation cost. In CMA's view such a calculation is unacceptable.

CMA states that adoption of an accurate fuel cost estimate for the calculation of marginal energy costs is crucial, as this estimate significantly affects many aspects of rate design. For this reason CMA asserts that the Commission's adopted method for the calculation of Southern California Gas Company's G-COG rate suggests an appropriate method of deriving a more accurate estimate of Edison's incremental fuel cost for test year 1985 than the $5.80/mmbtu used by Edison and the staff. That rate is set by the calculation of the recorded monthly weighted average GN-5 rate using both episode day and non-episode day rates.

Alternatively, CMA recommends that the same incremental fuel price used to develop test year marginal costs be used to forecast ECAC rate levels and revenues. CMA suggests that the greatest degree of consistency and accuracy of estimation would be achieved by utilizing the fuel price forecast and ECAC rates which will be established in the disposition of Edison's ECAC A.84-02-11 which is now before the Commission.

CMA also objects to staff's suggestion that forecasts of the appropriate fuel costs and other significant inputs related to staff's methodology be updated. According to CMA, adoption of staff's suggestion would result in the Commission going outside the record in these proceedings to find the values of inputs to the marginal cost methodology. CMA asserts that the Commission's

alternatives in this regard are limited to applying the input assumptions on the record in this proceeding, reopening hearings on the updated forecasts, or setting rates on the basis of some other cost calculation methodology.

Like other parties, IEP's primary concern is the accuracy of the input assumptions used in Edison's PROMOD and staff's IAm Models. The assumptions of concern to IEP relate to hydro estimates, purchased power quantities, nuclear plant performance, and load and peak demand forecasts. IEP also believes that incremental heat rate factors adopted contingent on the inclusion of Palo Verde 1 and 2 and SONGS 1 should contain reasonable estimates for the performance of these units. In addition to issues related to assumptions, IEP recommends that the Commission adopt a hybrid of the "Zero Intercept" method proposed by Edison and the staff's 500/btu adjustment. IEP also suggests that variable O&M should be increased by 3-5 percent and that the staff's working cash allowance be included in the marginal energy cost calculation.

With respect to IEP's recommended adjustments to the input assumptions, IEP notes that its adjustments are based on later information than that used by Edison in running PROMOD. IEP states that its recommended input assumptions were generally either directly taken from or derivable from the input assumptions for the same quantities used in Edison's ECAC A.82-04-11. IEP asserts that its assumptions are undisputed by any party.

Specifically, IEP recommends use of the following input assumptions:

- Edison's ECAC hydro quantities should be used. According to IEP, Edison decreased its estimate of hydro energy availability under average water conditions by 600 gWh between its PROMOD run and its ECAC filing.
- Edison's ECAC figures relating to the availability of purchased power to Edison system should be adopted. IEP believes that the ECAC filing, on

which IEP relied in their testimony, made an attempt to forecast purchased power taking into account limits on availability of power and transmission line capacity which PROMOD did not.

- Edison's ECAC estimates for the performance of immature nuclear plants should be adopted. In ECAC, Edison took the position that the appropriate capacity factor for immature nuclear plants was 60 percent and the production factor averaged 66.5 percent for SONGS 2 and 3. The corresponding figures used in Edison's PROMOD run were 63 and 69 percent respectively. Additionally, the ECAC filing contained a more recent maintenance schedule for the two units which indicated that SONGS 2 would be out of service in January and part of February, instead of operating all year as PROMOD suggests.

  For SONGS 1, the Commission should use Edison's ECAC production factor of 72 percent, instead of the 83 percent factor used in PROMOD. Palo Verde 1 and 2 should have the same 66 percent range as SONGS 2 and 3. According to IEP, there is no reason why the Palo Verde units will perform better than SONGS 2 and 3 when immature.

- Several adjustments to Edison's demand forecast should be adopted. First, the load forecast should be based on Edison's ECAC demand forecast as opposed to the much earlier developed PROMOD figure. Second, the Metropolitan Water District pumping load in the test year should be increased by 505 gWh over that used in PROMOD. The source of this adjustment is Edison's CFM-V submittal to the California Energy Commission. Finally, the peak demand forecast should should be the 13,860 mW of peak load reflected in Edison's resource plan.

Like CMA, IEP believes that any updating of input adjustments should be limited to the record in this proceeding. In this case, IEP believes, however, that it has provided the needed basis for such updating in its testimony. In the case of the demand forecast, IEP recommends that later information available in the September updating hearings in this proceeding

should be used. Finally, IEP urges adoption of Occidental/Ultrasystems' recommendation on the appropriate gas price for developing Edison's IER and the staff's exclusion from the marginal energy cost calculation of SONGS 1 and Palo Verde until these units are available.

With respect to methodology, IEP concludes that Edison's "zero intercept" method has several reasonable features. First, IEP argues that this method provides for use of the total cost portion of PROMOD, which is better validated than the marginal cost module, if Edison's model is used, and for use of the staff's public domain PCAM model instead of its proprietary IAM model, if the staff model is used. Second, the method provides for a greater allocation of costs to the time periods when the minimum load costs are avoided--on-peak and mid-peak--than the staff method of allocating 500 Btu to all time periods. Recognizing the staff's legitimate point that models generally dispatch the system more efficiently than reality, however, IEP recommends the "zero intercept" method be used incorporating a 200 Btu/kWh adder for "human behavior."

IEP also supports a variable O&M component of 2.07 mills/kWh based on the testimony of Edison's witness Jurewitz, as opposed to a 2 mill figure adopted by the Commission in previous proceedings. IEP also finds reasonable staff's inclusion of a working cash component in the marginal avoided cost calculations consistent with the Commission's decision in PG&E's last general rate case.

(2) Edison's Alternative Approach (Exhibit 9(A))

IEP and Federal support, with certain modifications, Edison's proposed alternative to QF energy pricing. In IEP's opinion, Edison's proposal is a creative and reasonable step to increase the verifiability of prices paid to QFs and reduce the reliance on "black box" computer modeling efforts. IEP believes that this simplified method is reasonable because it:

- Recognizes that Edison's marginal units are largely oil/gas fired power plants;
- Accounts for periods of time when oil and gas are not marginal;
- Tracks the units which generate the most energy; units with lower capacity factors are weighted less in calculation of average heat rates;
- Reflects QF avoidance of start-up, no-load, and minimum load fuel costs.
- Finally, the recorded data on which these calculations are made is generally available and verifiable in ECAC proceedings.

For IEP, only a few questions remain with regard to the data. One concern is whether the rejected energy prices are at the point of purchase or at the point of entry to the Edison system. IEP believes that the rejected energy price should include off-system losses.

IEP also proposes two minor modifications to the method. First, IEP believes that a five-year rolling average is more appropriate than a two-year average. According to IEP, this longer average would further mitigate price fluctuations caused by variations in economic conditions, weather-related hydro and purchased power, and nuclear plant forced outages and maintenance scheduling. The result would be more stable QF prices for both QFs and ratepayers.

Second, since rejected energy prices were not available in 1982, IEP would synthesize another year of rejected energy prices for 1982 because 1983 was an atypical year due to the price of the purchased power. IEP recommends that for the two-year period of 1982 and 1983, a rejected energy price ratio of 34.5 percent of the cost of gas be used instead of the 32.3 percent recommended by Edison. The result would be an increase in off-peak prices of about 100 Btu/kWh.

IEP states that staff's concerns with Edison's alternative approach are either "invalid or easily addressed." In IEP's opinion, the capacity factors of retired or cold standby plants were so low in 1982 and 1983 that the inclusion or exclusion of these plants makes almost no difference to the numbers used in Edison's calculation. Further, the Commission could direct Edison to recalculate its 1982 and 1983 numbers without them.

IEP also responds to staff's concern that oil/gas generation will decrease as new nuclear units are added and that Edison's method may not reflect it. In IEP's view this objection must be examined with reference to IEP's testimony on oil/gas use in the 1985 test year, not the PROMOD data relied upon by Edison and staff. IEP asserts that it has demonstrated that the high hydro and purchased power conditions in 1982 and 1983 roughly approximated the impact of Edison's new nuclear units and that test year 1985 oil/gas generation should be more, not less than that recorded in 1983.

---

[1] IEP in its discussion of Edison's alternative methodology for QF energy pricing also suggests that with Edison's development of a significant number of minimum load hours, a QF curtailment option may prove valuable to both the Edison system and QFs. While stating that the terms of such an option are beyond the scope of this proceeding, IEP does urge the Commission to include a finding in this decision encouraging negotiated contracts on QF curtailment in the Edison system. We respond to this suggestion by noting that the terms of QF standard offers or negotiations are not an issue in this proceeding and that our current policy on these issues are fully discussed in our many decisions issued in OIR 2, A.82-03-26, et al., and A.82-04-44, et al. No further discussion of these issues in this decision is appropriate or required.

Federal "enthusiastically" supports Edison's proposal to use recorded average heat rate data for gas/oil units. The approach, in Federal's view, provides the following critical advantages over alternatives which rely on projections by complex, almost impenetrable computer models:

- o Recorded heat rate data is routinely gathered by Edison, is highly accurate, and is easily verified.
- o Recorded heat rate data is already evaluated and relied upon by the Commission for a number of other regulatory purposes, such as ECAC proceedings.
- o Recorded heat rate data is easily understood by QFs.
- o Because Edison's proposal utilizes a composite of several years data, it reduces the likelihood that the results will vary dramatically from year-to-year. This increases certainty and reduces the risks to QFs.
- o Recorded heat rate data includes startup and no-load conditions which are not included in the PROMOD algorithim used by Edison. This eliminates the need for the highly-judgmental adjustments adopted by the Commission in the past.

Federal echoes IEP's comments that Edison's approach would substitute an understandable and verifiable methodology (i.e. recorded heat rates) for the nearly impenetratable machinations of the computer simulation model.

Federal, however, has substantial reservations about the data underlying Edisons's rejected economy energy proposal. Federal believes that this proposal is flawed in several respects. First, only one year of actual pricing data was available on which to base Edison's finding that rejected energy represented 32.3 percent of the cost of oil and natural gas. Edison's proposal fails to compensate for the extraordinary (wet) weather conditions which existed in the two-year period. Third, the causal relationship

between QF output and rejected energy was not made clear on this record. Fourth, the rejected economy energy prices exclude line losses.

For these reasons, Federal makes the following recommendations. At a minimum, the proposed change to the 1982 economy energy prices suggested by IEP should be adopted in order to compensate, at least partially, for the effects of the extremely wet hydro conditions during the last two years. In addition, a line loss adjustment should be made to the economy energy prices. Federal also endorses IEP's proposal to move towards a five-year data base for determining both rejected economy energy prices and average heat rates.

Because of the many uncertainties regarding the rejected economy energy data, Federal strongly urges the Commission to address this issue more fully at the very next opportunity. In light of the Commission's decision to delay the next Edison rate case for an additional year, Federal urges the Commission to include this issue in the long-run incremental cost proceeding (A.82-04-044). In IEP's opinion, consideration of this issue in the long-run avoided cost case, which is still in Phase 1, would not materially delay that proceeding.

Federal's endorsement of Edison's alternative approach was unaltered by staff's objections to the proposal. Federal believes that the problems pointed out by the staff are either insignificant or offset by other factors. Further, projected 1985 oil and gas consumption is higher than 1982-1983 actual consumption even when forecast increases in nuclear output are considered. If further study of Edison's approach is ordered by the Commission, Federal urges that the approach be adopted on an interim basis pending the outcome of that study.

d. Discussion

As the uses for marginal energy costs in ratemaking have increased, so have the factors which this Commission must consider in adopting a methodology for calculating those costs. It is obvious that there is some concern that this Commission's decisions might result in favoring one of three allegedly competing interests--either ratepayers, the utility, or qualifying facilities.

It is not our intention to create or recognize any kind of competition among these interests. Our goal is only to adopt methodologies which will most accurately reflect the utility's avoided and marginal costs. We categorically refute the assertion of GM/Union Carbide that we consider costing accuracy to be of value only where QFs are concerned. The accuracy of the costs and assumptions adopted by this Commission in determining a utility's marginal energy costs are critical for all purposes for which such costs are used (i.e., revenue allocation, rate design, conservation and load management, and QF pricing). This is not to say that we will always adopt a full marginal cost rate design. In certain circumstances we may deviate from a pure marginal cost rate design. Nevertheless, it is still important to have accurate estimates of marginal costs as such estimates are carefully considered in our rate design decision.

For these reasons, we reiterate our earlier stated policy to adopt one methodology for the calculation of marginal and avoided energy costs. Originally, Edison had proposed that the same IER developed by using PROMOD would be used for calculating marginal and avoided energy costs. Only later did Edison suggest an alternative approach which would be appropriate for QF energy pricing alone. While the QFs may value a methodology which will be verifiable and understandable, the Commission must regard with some skepticism a proposal for developing incremental energy rates, a key component in marginal and avoided energy costs, which is apparently only suitable for QF pricing. We must assume from this differentiation that the proposal could result in an incremental

energy rate different from that developed for other ratemaking purposes. We are also concerned that even the parties supporting Edison's alternative methodology have reservations regarding certain

of Edison's calculations--in particular, that related to rejected energy.

We commend Edison for its efforts with respect to responding to the needs of QFs. We also appreciate the problems which computer models can create with respect to QFs' verifying data and related outputs. We are, however, committed to forecasting the utility's marginal costs with the result that the rates and prices in effect in the test year will most accurately reflect the test year, not past year, conditions.

IEP, Federal, and Edison give little weight to the staff's assertions that differences in resources and conditions existing in 1982 and 1983 will produce an IER not related to conditions existing in 1984. These parties argue that the factors raised by the staff will not result in a significantly different incremental energy rate than one based on one of the computer methodologies.

We, unfortunately, cannot dismiss the staff's objections so easily with a three-year rate case plan in place. We must become more committed than ever to adopting a methodology for calculating IERs which looks to the future. Thus, even if some of staff's objections to Edison's alternative can be minimized, we cannot dismiss the basic premise for staff's objections--that premise being that 1983 and 1984 operating conditions for Edison will not mirror those for test year 1985.

We also note that beginning with PG&E's most recent rate case decision (D.83-12-068), we have made a concerted effort to minimize the "black box" aspect of marginal cost calculations performed by computer models. In that decision, we directed that the staff and other parties would have access to the utility's computer model. In A.82-04-44, et al., related to payments to qualifying facilities based on long-run avoided costs, the ALJ, as we instructed in D.82-12-068, has adopted guidelines by which such access can be achieved.

We also find meritorious staff's suggestion regarding an OII into the subject of a uniform computer model. Even though Edison has proffered a methodology for calculating IERs which might not require a computer model, the use of a production cost model for multiple purposes is currently widespread among the utilities and it is only reasonable to expect it to increase. Edison's objections to such an OII reads like the list of reasons a QF might give for disdaining a utility's use of computer models. If only to overcome QF suspicion regarding computer models, the issue of a statewide computer model is certainly worth exploring. Further, such a proceeding, even if it did not lead to the implementation of such a model, would at least provide a forum for examining the exact constitution, limitations, and uses of the utility's computer models.

We therefore conclude that the incremental energy rate used in Edison's marginal and avoided energy cost calculations should be developed using Edison's computer model. Further, a computer model approach is reasonable for use in developing Edison's final marginal and avoided energy costs.

To ensure that the resulting costs most accurately reflect the test year conditions, we will adopt all of those suggested resource and input changes which embody the most up-to-date verifiable information. CMA and IEP correctly state that the only record to which we can look for such updated information is this proceeding. Although we, like those parties, are uncertain what type of updating the staff contemplated, we find that this record provides an adequate basis for updating the assumptions originally inputted to PROMOD. Based on this record, the following adjustments in PROMOD assumptions are reasonable and should be made:

- The appropriate resource mix to be used in the marginal energy calculation is that existing at the commencement of the test year. Under these circumstances, Palo Verde Nuclear Generating Station Unit 1 (PVNGS I) should be excluded from the resource assumptions, while, based on current estimates of operation in 1985, SONGS 1 should be included.

- The updated peak demand level reflected in Edison's resource plan (13,860 mW) should be used in deriving Edison's IER.
- Edison's IER should be based on an estimate of fuel costs of $5.01/mmbtu.
- Edison should alter other input assumptions to reflect, as IEP has proposed, the hydro quantities stated in its ECAC filing, A.84-02-11; the figures for the availability of purchased power developed for the same ECAC filing, the estimates for the performance of SONGS 1, 2, and 3 also presented in A.84-02-11; a 66 percent production factor for PVNGS 2; and a load forecast based on Edison's demand forecast in A.84-02-11.

We must now decide what methodology should be used to derive Edison's marginal energy cost from the adopted assumptions. We note staff's statement that the driving algorithms or formulas for PROMOD and IAm are the same and that differing results produced from the two models may be caused by the way the models handle certain conditions. It is obvious that both the staff and Edison have responded to observed shortcomings of their models either by adjusting the methodology by time period and season or by adding energy values to each time period.

We have insufficient evidence in this proceeding to declare that PROMOD is an inadequate production cost simulation model or that another model is necessarily superior. It is therefore reasonable for this Commission to rely on Edison's use of its PROMOD model to calculate Edison's marginal energy costs. We will therefore direct staff to follow the methodology which Edison proposed for calculating its marginal energy costs in the off-peak periods and the "zero intercept" methodology for on- and mid-peak periods.

A final issue regarding marginal energy costs is the appropriateness of using the GN-5 rate (i.e., the rate paid by an electric utility to its gas utility supplier) as the marginal fuel cost. This issue was raised in PG&E's last general rate case, and remains a concern of this Commission.

> "...we come to this conclusion realizing that the current G-55 rate used in developing marginal energy costs may not be the best estimate of the economic value of QF power, conservation, and load management to the utility system. We instruct PG&E and staff to address further in PG&E's next general rate case the question of what marginal fuel price should be used in evaluating these resources." (p. 340 D.83-12-068)

For the purpose of this proceeding, we will use the GN-5 rate for calculating marginal energy costs, but we instruct Edison and staff to address this issue in Edison's next general rate case. We expect parties in Phase II of our proceeding on avoided cost methodologies (A.82-04-44 et.al) to also address the question of what marginal fuel price should be used in evaluating these resources.

As discussed previously, a utility's marginal energy cost includes other components such as O&M expenses. The issue raised in this case is whether the marginal energy cost calculation should also include A&G expenses or cash working capital.

In this proceeding, staff proposes that A&G expenses and cash working capital be included in the marginal energy cost calculation. IEP supports this position. Edison believes that no evidence exists for inclusion of either component in this calculation and further notes that A&G expenses are already accounted for in the capacity cost calculation.

In Decisions 83-12-068 and 83-12-065 (PG&E and SDG&E general rate cases) we determined that for QF pricing, cash working capital should be included. Consistent with our prior decision, and based on staff's showing, we will again order the inclusion of cash working capital in a utility marginal energy cost.

With regard to the inclusion of A&G expenses, however, our prior decisions are inconsistent on this issue (D.83-12-068 did not include them, while in D.83-12-065, these expenses were included in marginal energy costs). We are persuaded by Edison's showing in this case that A&G expenses are already accounted for in the capacity calculation. The A&G component will remain in the capacity calculation, and not be included in marginal energy costs.

Finally, staff recommends that because of data gathering problems experienced in this proceeding, all utilities should be required to provide computer input and output data supporting their exhibits simultaneously with the filing of their applications. We believe that this suggestion has merit and will hopefully expedite the review and enhance the understanding of a utility's application by the staff and other parties. We will direct Edison in its next general rate case to provide related computer data upon the filing of its application. We will coonsider applying the same rule by resolution to other utilities.

The incremental energy rates and the marginal cost of energy adopted in this decision are shown in the following tables.

TABLE 2

INCREMENTAL ENERGY RATE FACTORS[a]

SOUTHERN CALIFORNIA EDISON COMPANY

TEST YEAR 1985 GENERAL RATE CASE

	BTU/KWh	Time Periods
Summer		**June - September**
On-Peak	13786	Noon to 6 p.m., Weekdays
Mid-Peak	10576	8 a.m. to Noon and 6 p.m. to 11 p.m., Weekdays
Off-Peak	9006	All other hours
Non-TOD	10252	
Winter		**October - May**
On-Peak	13006	5 p.m. to 9 p.m., Weekdays
Mid-Peak	10456	8 a.m. to 5 p.m., Weekdays
Off-Peak	9006	All other hours
Non-TOD	9841	
Annual Average	9983	

a/ Gas fired IER at generation level with avoided working cash allowance (0.018¢/KWh) rolled in. Avoided variable O & M payments of 0.2¢/KWh to be made as a separate accounting item.

TABLE 3

MARGINAL COST OF ENERGY

SOUTHERN CALIFORNIA EDISON COMPANY

TEST YEAR 1985 GENERAL RATE CASE

	Mills/KWH	Time Periods
Summer		**June - September**
On-Peak	69.07	Noon to 6 p.m., Weekdays
Mid-Peak	52.99	8 a.m. to Noon and 6 p.m. to 11 p.m., Weekdays
Off-Peak	45.12	All other hours
Non-TOD	51.36	
Winter		**October - May**
On-Peak	65.16	5 p.m. to 9 p.m., Weekdays
Mid-Peak	52.38	8 a.m. to 5 p.m., Weekdays
Off-Peak	45.12	All other hours
Non-TOD	49.30	
Annual Average	50.01	

a/ Includes avoided working cash allowance (0.013¢/KWH). O & M will be added as a separate accounting item. Figures are based on forecasted fuel costs adopted in this general rate case. Actual energy payments to QFs will be revised quarterly based on actual fuel costs.

2. Marginal Cost of Demand: Generation, Transmission and Distribution

The marginal cost of demand refers to the cost changes which result from a change in demand on the utility system and is expressed in cents per kilowatt. These costs relate principally to plant associated with generating and transporting the electricity necessary to satisfy the marginal demand.

In prior rate cases, we have separately examined the marginal cost of generation and the marginal cost of transmission and distribution. All of these costs, however, are part of the marginal cost of demand which we have previously concluded should be based on the utility's shortage costs. We distinguish between these components only to note that because transmission and distribution costs are not avoided by utility purchases of QF power, such costs should not be included in payments to QF facilities. The propriety of including avoided transmission and distribution costs in cost effectiveness calculations is addressed in our discussion of conservation cost-effectiveness.

The methodologies utilized by Edison and the staff to calculate the marginal cost of demand are identical. The actual values which result are different solely due to Edison using a real inflation rate of 7 percent and the staff using real inflation rate of 6 percent in the development of associated economic carrying charges. The values determined for marginal generation, transmission and distribution costs are annual values. These values are allocated among the seasonal and diurnal costing periods using capacity response ratios.

To determine marginal demand costs and ultimately total marginal costs, time and seasonally differentiated marginal cost components are added. The conversion of costs from dollars per kilowatt to cents per kWh occurs by dividing the monthly dollar per kilowatt charges by the number of hours in each costing period.

Both Edison and the staff base their values for the marginal cost of generation on the full annualized cost of a combustion trubine. As stated previously the combustion turbine serves as the proxy value for a utility's shortage cost.

The primary issue related to the calculation of the marginal cost of demand is whether the full value of a combustion turbine is the appropriate measure of the utility's shortage costs or whether that value should be adjusted to reflect the actual generation reliability situation which exists. It is Edison's position that no adjustment to the full annualized value of a combustion turbine is appropriate for retail rate design purposes "unless a utility has a substantial shortage or excess of capacity which is expected to persist for an extended period of time." The staff concurs with this approach and does not recommend any adjustment to this full value for rate design purposes.

During the hearings, however, the staff did recommend that an adjustment be used in calculating QF capacity payments, which are also based on the value of a combustion turbine. No similar adjustment was recommended by Edison or any other party to the proceeding. Further, each of the parties commenting or testifying on staff's recommendation have urged the Commission to reject staff's proposal.

Specifically, staff has proposed a Reliability Adjustment Factor or RAF, which in some ways is related to the adjustment mechanism known as the Energy Reliability Index or ERI adopted in PG&E's general rate case. (D.83-12-068, at pp. 343-348, 424.) Use of the RAF first requires a determination of the appropriate planning reserve margin for Edison, which the staff determined to be 18 percent. The RAF then looks at a comparison between the planning reserve margin and the actual reserve margin in the years during which the QF capacity contract is in effect. Borrowing from the ERI, the RAF is set equal to 1 (no adjustment) at

a point where the planning and actual reserve margins are the same, at a cap of 2 when the reserve margin declines to 5 percent or less (the point at which Edison's emergency plans are triggered), and at zero based on what reserve margin is intercepted by a straight line drawn between the prior two points.

None of the witnesses who presented testimony in opposition to the RAF disagree with the proposition that the value of QF capacity to Edison and, in turn, its customers is related to the reliability situation which Edison is experiencing. These parties, however, vigorously oppose staff's proposal on the grounds that it is technically flawed.

Edison argues that staff's RAF methodology is unsuitable for adjusting QF capacity payments for several reasons. First, the RAF requires the adoption of a single invariant reserve margin criteria for every year. Second, the RAF reflects an oversimplified approach of equating the reserve margin, which is a deterministic index, with system reliability, which is a probabilistic index. Finally, instead of using all three installed capacity criteria upon which Edison has designed its resource plan, the RAF has been calculated using only one of these criteria. Edison asserts that singling out only one of these criteria misstates the value of near-term capacity.

IEP joins Edison in objecting to staff's RAF proposal. IEP believes that the record fails to provide the support necessary for the Commission to conclude, as we did in PG&E's general rate case, that RAF-adjusted shortage costs contain no systematic bias and that RAF-adjusted shortage costs are more accurate than unadjusted shortage costs for Edison. Rather, IEP asserts that the Commission must reject the RAF and continue to use the unadjusted value of the combustion turbine for the following reasons:

- Edison's needs for capacity and Edison's available capacity resources are approximately in balance over the term when RAF adjustments would apply to QF prices. There is no significant overcapacity.

- The arithmetic construction of the RAF results in a systematic downward bias in prices.
- The RAF is oversimplified in that it does not directly consider reliability of individual powerplants.
- Staff in developing the RAF ignored Commission directives to use and perfect an Expected Unserved Energy (EUE) reliability standard to avoid systematic bias even though it had the technical capability of making EUE calculations.

IEP concurs with Edison, however, that the major reason for rejecting the RAF is that there is no single immutable reserve margin that applies in every year. In IEP's opinion, the Commission should recognize that reserve margin requirements are not constant over time.

Occidental/Ultrasystems also provided substantial comment and testimony on the issue of using the RAF. In their opinion, the RAF's mismatch in reliability criteria yields nonsensical, biased results. Further, the RAF fails to capture annual variations in target system reliability. Occidental/Ultrasystems also argue that the RAF is conceptually unsound in that it allows the possibility of a zero shortage cost. Finally, they conclude that staff's implementation of the RAF is inconsistent with Commission guidelines in treating uncertainties in a deterministic manner and in failing to conduct sensitivity analysis on the results.

The Department of General Services of the State of California (Department) similarly asserts that the staff's RAF proposal is analytically flawed. The Department argues that the staff has simplified the anlysis of a complex issue and in doing so has ignored many points that the Commission found significant in its decision adopting PG&E's ERI

In the wake of this substantial opposition to its proposal, the staff in its opening brief withdrew its recommendation that the RAF be adopted by the Commission at this time. While still asserting the conceptual propriety of using such a mechanism, the staff concedes that some of the criticism of the RAF is valid. In particular, the staff notes that the linearity of the RAF may be inappropriate--QF capacity value may be relatively greater at some reserve margin levels than at others. Further, the staff agrees that determining the appropriate measure of reserve margins in specific years may need some further consideratin. Staff suggests that an appropriate forum to provide such consideration would be an OIR-2 related proceeding.

Based on the record in this proceeding, we concur that staff's proposed RAF is technically flawed and that we are precluded from making the same findings with respect to the RAF which permitted our adoption of PG&E's ERI adjustment factor. Like the staff, however, we believe in the conceptual merit of such an adjustment mechanism or any other device which can, if adequately supported, provide the most accurate determination of marginal or avoided costs.

We advise the staff and all interested parties, however, that the forum for discussing such proposals is the general rate case, not an OIR-2 related proceeding, as we have clearly stated in our decisions in A.82-03-26, et al. The staff is apparently aware of some of the shortcomings of the RAF and has had others delineated for it by other parties to this proceeding. We are very disappointed that we are unable to adopt a QF capacity payment adjustment mechanism, especially since we are concerned that Edison may currently be in an excess capacity situation (see section on resource planning). We would like to implement an apropriate adjustment mechanism as soon as possible in order to provide accurate price signals and avoided costs to QFs. In PG&E's TY1984 General Rate case, we instructed PG&E to develop an Expected Unserved Energy

(EUE) reliability criterion for use in adjusting shortage costs (D.83-12-068, pg. 364). Similarly, we now direct staff and Edison, preferably in cooperation with other electric utilities, to develop and present and improved capacity adjustment mechanism in subsequent proceedings based on an EUE reliability criterion. The criticisms and technical flaws of the proposed RAF identified in this proceeding should be corrected.

In order to get the capacity adjustment mechanism issue before us as soon as possible, and in order to consider factors of changed circumstances which impact avoided energy and capacity costs, we are actively considering instituting an annual or periodic procedure which will allow us to more frequently adjust the energy and capacity price offers for Standard Offers 1, 2, and 3. Such an annual adjustment procedure, as opposed to adjustments once every three years during a general rate case, would result in more responsive and accurate avoided costs. It might also obviate the need for emergency Commission action such as that taken recently in D.84-10-098 regarding PG&E's Standard Offer 4.

No other objections were voiced with respect to the basic methodology (use of a combustion turbine proxy) for calculating Edison's shortage costs. We therefore adopt the methodology proposed by Edison and the staff based on the unadjusted annualized value of a combustion turbine. We find reasonable and more realistic Edison's proposed real inflation rate of 7 percent and adopt that figure for the final calculation of the marginal cost of demand and QF capacity prices. The following table shows our adopted QF capacity price schedule. We note that again our findings result in the same methodology being applied to the multiple purposes for which marginal costs are used.

While the basic methodology adopted above was uncriticized, a number of parties did object to the staff's and Edison's method of converting of the marginal cost of demand to an energy basis before multiplying the result by class energy consumption to yield class marginal demand costs. Basically, this concept refers to synthesizing kilowatts into kilowatt-hours which are then multiplied by cents per kilowatt hours.

In the opinion of the Federal Executive Agencies (FEA), the Association of California Water Agencies (ACWA), and CMA this approach results in a determination of class marginal cost revenues which is biased against the higher voltage, higher load factor customer classes. CMA again suggests the return to basing rates on Edison's actual cost of service, while ACWA and FEA propose different methods or formulas for accomplishing the synthesization.

The staff's and Edison's approaches to the conversion of marginal costs of demand to class responsibility are not substantially different from each other and follow the basic methodology adopted in previous rate cases. We find staff's approach to be an appropriate means of putting the theory of marginal cost ratemaking into practice and of determining class marginal demand costs in as effective a manner as that suggested by FEA and ACWA. We have previously rejected CMA's continuing suggestion to reinstate embedded cost ratemaking. We therefore find reasonable staff's approach for converting the marginal cost of demand to class marginal demand costs and adopt it for purposes of this proceeding.

Table 4

SOUTHERN CALIFORNIA EDISON COMPANY

Adopted Capacity Price Schedule for Test Year 1984

$/KW-Year

Year of Initial Delivery	Contract Term (Years)						
	1	5	10	15	20	25	30
1985	83	92	105	116	125	132	138
1986	88	99	112	124	133	141	146
1987	94	105	120	132	143	151	155
1988	100	113	128	141	153	162	165
1989	107	121	137	151	164	173	175

Monthly Capacity Allocation Factors: The following factors are adopted for conversion of the above annual capacity values to monthly payments-by-time periods of delivery, the time periods being the same as in the proposed costing periods for marginal costs.

Time Periods	Summer	Winter
On-Peak	0.1643	0.0245
Mid-Peak	0.0028	0.0123
Off-Peak	0.0025	0.0036

3. Marginal Customer Costs and Facilities Charges

Marginal customer costs are defined by Edison as those costs resulting from the addition of new customers to the system. They include the capital costs of a minimum distribution system, associated operation and maintenance expenses, customer accounts expenses, and customer service expenses. The staff agrees with this basic definition with the exception of the inclusion of costs related to the minimum distribution system and the cost of utility provided streetlights to customers on the LS-1, OL-1, and DWL schedules.

Calculated for informational purposes only, marginal customer costs are, in the opinion of the staff and Edison, not appropriate for inclusion in revenue allocation process since they are not marginal costs related to changes in output, but rather are related to changes in the number of customers. In contrast, the FEA argues that the Commission should include all capital costs and customer specific costs in its determination of marginal costs and marginal cost revenues. CMA and the Schools Committee for Reducing Utility Bills (SCRUB) concur with this position. SCRUB asserts that the exclusion of marginal customer costs causes a distorted revenue allocation and an inaccurate price signal to customers. In CMA's opinion, marginal customer costs are real costs which the utility will recover through its base rates in the test year. Furthermore, these costs can be attributed to the customer groups responsible for imposing these costs on the system. According to CMA's witness, the ultimate effect of a revenue allocation which ignores marginal customer costs is the creation of a subsidy for groups with relatively high marginal customer costs from groups with relatively low customer costs.

We find conceptual merit in the views of FEA, CMA and SCRUB. As a starting point, we believe that all components of marginal costs should be included in marginal cost revenues. However, we stress that these costs should be truly marginal and not

based on embedded or historical accounting costs as proposed by CMA. Once we have estimates of these marginal cost revenue, we may choose to deviate from strict marginal cost pricing principles based on considerations of equity or other rate design goals.

In situations where marginal cost revenues are higher than our authorized revenue requirements, pure economic theory dictates that we partially, or totally eliminate from revenue allocation and rate design charges that customers are the least able to respond to (i.e., those with relatively inelastic demand). During periods where marginal cost revenues are lower than authorized revenues, economic theory requires increasing those "demand inelastic" marginal cost components until the revenue requirement is achieved. This approach will keep consumption and resource allocation patterns as close to those that would occur if we truly priced electric services at marginal costs.

We consider marginal customer costs to be the "demand inelastic" component that should vary, depending on the relationship between marginal and authorized revenues. In this case, as in the case of PG&E's TY 1984 general rate case, marginal cost revenues are somewhat higher than authorized revenue requirements, even after eliminating marginal customer costs from the allocation process. Therefore, we find that economic efficiency and our rate design goals are best achieved by eliminating those costs from our revenue allocation method.

We continue to be concerned that the marginal customer cost calculations presented in these hearings include embedded or historical accounting costs. We direct all parties to develop a methodology and present incremental, or marginal cost-based customer costs in Edison's next general rate case.

4. Marginal Costs by Customer Group

Marginal costs are used in rate design to apportion the adopted revenue requirement among customer classes. Marginal costs are developed for each customer class from the energy and demand costs corresponding to the voltage level at which the class receives service. The marginal cost of demand (including T&D costs) is further adjusted by class load and coincidence factors. Annual marginal costs for a customer class are derived by weighting the on, mid, and off-peak marginal costs by the percentage of consumption in each period. The synthesization of the marginal cost of demand to class marginal demand costs was previously discussed. Table 5 presents the adopted annual marginal costs by customer class.

Revised 12/7/84

TABLE 5

SOUTHERN CALIFORNIA EDISON COMPANY
SUMMARY OF MARGINAL COSTS BY CUSTOMER GROUP

TEST YEAR 1985

¢/kWh

Line No.	Item	Marginal Cost Components				
		Energy	Generation	Transmission	Distribution	Total
1	Domestic	6.09	1.71	0.62	0.55	8.97
2	Streetlighting	5.72	0.50	0.19	0.38	6.79
3	Lighting, Small & Medium Power	6.20	2.09	0.76	0.59	9.64
4	Agricultural & Pumping	6.06	1.90	0.69	0.59	9.24
5	Lighting, Large Power	5.83	1.55	0.56	0.50	8.44

XII. REVENUE ALLOCATION

The establishment of electric rates is a three-part process: (1) determining the utility's revenue requirement and marginal cost, (2) adopting the appropriate method of allocating that revenue between customer classes, and (3) finally, setting the actual rates. In the prior sections, we have dealt with the first part of this process--determining Edison's revenue requirement and marginal cost. Our adopted marginal cost by customer class is set forth in Table 6.

With the completion of that step, we turn to the second part of the ratemaking process--revenue allocation. Revenue allocation involves reconciling the revenue requirement and the revenues that would be generated at full marginal cost pricing. In this proceeding, the major issues related to revenue allocation include determining the method to be used to reconcile total revenues with marginal cost revenues, the revenue allocation approach to be used in the absence of a rate increase, the revenue allocation approach to be used between general rate cases, and the propriety of excluding particular customer classes (i.e., schools and street lighting) from a revenue allocation process based on marginal costs.

A. Revenue Allocation Methodology

1. Proposed Methodologies

In Edison's view, revenue allocation and ratesetting should be accomplished in accordance with certain recognized rate design principles. Edison believes that these principles should encompass the recovery of revenue requirement, marginal cost, revenue stability, conservation of electrical energy, load management, baseline allowances and baseline rate levels, and rate history and customer acceptability.

Guided by these principles, Edison concludes that the 100 percent Equal Percentage of Marginal Cost (EPMC) approach is the only reasonable method for allocating the revenue requirement among

the various customer classes. This methodology, as proposed by Edison, allocates the total test year 1985 revenue requirement to customer groups on the basis of the ratio of the total revenue requirement to total marginal cost revenue applied to each customer group's marginal cost revenue. Edison asserts that the 100 percent EPMC methodology satisfies all of the accepted rate design principles; is conceptually sound, a conclusion unchallenged by any other party; and meets the staff's criteria of not varying any customer group's increase, other than for street lighting, by more than five percent from the increase given any other customer group.

The full EMPC approach is also supported by several interested parties including CMA, FEA, and GM/Union Carbide. According to CMA, the EPMC method produces a rate spread which, more than any other offered in this proceeding, accurately reflects the marginal cost of electric service as this Commission has defined it. The full EPMC is therefore the only methodology which promotes conservation by signaling customers of the present cost of their consumption. CMA further notes that application of EPMC methodology in this case would also not cause any disparate or significant changes in rates for any customer class. CMA's support of the EPMC approach, however, is conditioned on the Commission having adopted CMA's proposed adjustments to marginal costs. As explained previously, these proposals were rejected.

The FEA and GM/Union Carbide similarly endorse Edison's proposal. GM/Union Carbide agrees with CMA that if marginal costs are to be used in ratemaking, the Commission must be prepared to accept the results of that approach without recourse to contrary adjustments. The FEA states that the EPMC methodology is the only class revenue requirement determination process which allows the Commission to maintain a neutral position with respect to the distribution of Edison's costs among its various customer classes. In GM/Union Carbide's opinion, the time is ripe to adopt the EPMC

methodology given the lack of any evidence indicating that any customer class would suffer a disruptive revenue change upon its implementation.

The staff and the Schools Committee for Reducing Utility Bills (SCRUB) propose approaches other than the full EPMC to allocate revenue among the customer classes. SCRUB actually makes two alternative recommendations. SCRUB proposes that either the Commission exclude SCRUB from the revenue allocation process (see discussion infra) or the Commission adopts SCRUB's proposed Policy Adjusted Class Marginal Cost (PACMAC) methodology of revenue allocation. The staff recommends a revenue allocation approach based on a 50/50 weighted average of System Average Percentage Change (SAPC) and EPMC. The SAPC approach involves changing the revenue for a given class by the percent change in total system revenues.

The staff has recommended a 50/50 weighted average of SAPC and EPMC to alleviate the impact of adopting a full EPMC allocation in this rate case. In the view of the staff witness, it would be less disruptive to customers if a transition to full EPMC were accomplished in two rate cases. Staff asserts that its approach is largely based on concerns which the Commission expressed with respect to implementation of the full EPMC method in the PG&E general rate case. The staff notes, however, that a full EPMC allocation is actually its goal. Therefore, if the Commisson wishes to do so, the staff would not oppose the adoption of such an allocation methodology in this case.

SCRUB believes that revenue allocation should properly reflect the cost imposed on the system by the particular class of customers and that one class of customers should not be responsible for cost imposed on the system by another class. In SCRUB's opinion, PACMAC achieves this goal by including all marginal cost components (i.e., marginal customer costs), by fully charging each customer

class for that class' short-run marginal costs, and then by allocating any remaining revenue requirements according to the class marginal cost responsibility. Should PACMAC not be adopted by the Commission, SCRUB endorses the adoption of the full EPMC methodology, even if all marginal cost components are not included.

2. Discussion

In our recent decisions in the PG&E and San Diego Gas and Electric Company (SDG&E) general rate cases, we adopted two different revenue allocation methodologies. For SDG&E, we used a 100 percent EPMC methodology (D.83-12-065, at p. 146). While moving to full EPMC had no adverse impact on residential customers in the case of SDG&E, it would have had an adverse impact on PG&E's residential customers. Therefore, for PG&E we chose a weighted average method of allocation consisting of 95 percent SAPC and 5 percent EPMC (D.83-12-068, at pp. 365-366) based on the following reasoning:

> ". . . we are concerned that the combination of an overall rate case revenue increase and implementation of the changeover from lifeline to baseline will produce significant, and disproportionate increases in electric bills for certain residential users. Accordingly, we are reluctant to move significantly in the direction of EPMC at this time. Furthermore, our goal is not necessarily to achieve full EPMC for the residential class. With each rate adjustment we must continue to be sensitive to the effect of these changes on the bills of individual residential customers. In each subsequent rate proceeding, it is our intention to examine closely and carefully the impact of moving towards EPMC on individual residential customers. Upon our examination we will then determine to what extent we find it reasonable to continue towards full EPMC for the residential class." (D.83-12-068, at p. 365.)

As in the case of PG&E, we are concerned that a significant and disproportionate increase in electric bills would result for Edison's residential customers if we were to adopt a full EPMC revenue allocation at this time. Today, we are authorizing a net revenue increase of $784.2 million as shown below:

Base Rates (A.83-12-53)	($115.8 million)
Offsets	
SONGS MAAC (A.84-02-40)	$300.0 million
ECAC (A.84-02-11)	0
Net Revenue Increase	$784.2 million

In addition to this overall revenue increase, baseline implementation will begin in March 1985, resulting in further rate increases for some residential customers. For these reasons, we will adopt a 95% SAPC - 5% EPMC revenue allocation method. This is consistent with our previous decisions and our policy of moving towards a full EPMC revenue allocation method.

B. Requests for Exclusion from Adopted Revenue Allocation Methodology

1. California City/County Street Light Association

The California City/County Street Light Association (Cal-SLA) asserts that streetlighting customers, in recognition of their unique characteristics and in keeping with the Commission's decision in PG&E's most recent general rate case, should be excluded from the revenue allocation process. Cal-SLA cites the following singular characteristics of streetlighting customers: (1) Unlike any other customer classes, the street light class contains two separate and distinct subclasses—customers who install their own street lights and merely buy energy from Edison (LS-2) and customers who purchase both the use of a streetlight and the energy to serve it from Edison. (2) Almost all customers in the street light class receive unmetered service. (3) The class's load characteristics are off-peak and level. (4) The class as a whole and individually uses a relatively small amount of energy.

According to Cal-SLA, these characteristics make it extremely difficult to estimate costs and revenues using Edison's allocation approach. In Cal-SLA's view, no party is able to determine what portion of the street light charge applies to energy and what portion to ownership, maintenance, and replacement of the facilities. Cal-SLA cites the Commission's Finding 159 in D.83-12-068 (PG&E general rate case) that the "street lighting class should not be subject to marginal cost allocation." In making this finding, the Commission cited the services additionally provided by the utility to street light customers, such as maintenance and upkeep, and the small quantity of energy used by the streetlighting class as compared to the total energy served by the utility.

The costs associated with the use of a utility provided street light are referred to as "facilities charges." Cal-SLA argues

that, in particular, Edison has improperly included the revenue from the facilities' charge as a marginal revenue. In support of its position, Cal-SLA cites the testimony of Edison's witness Jurewitz that the facilities charge is a customer related charge. As such, Cal-SLA argues that it should be excluded from the determination of marginal revenue responsibility for the street light class. Inclusion of the facilities charge added $38.1 million to the marginal revenue for street lights.

Edison believes that as "a matter of principle" the street lighting group should be included in the marginal cost-based revenue allocation process. With respect to the facilities charge in particular, Edison argues that while this charge is a customer-related cost, it is a unique street light-related marginal cost and should be included in the revenue allocation for the street light group. In Edison's opinion, the facilities charge is not the same as ordinary customer costs which are based on hooking up the customer to the utility system. While the customer hook-up cost is an integral part of the service to each customer, the facilities charge involves the choice available to street light customers to either rent or own their own facilities.

The staff is of the opinion that street lighting customers should generally be included in the revenue allocation process, but that facilities charges should not. The staff believes that facilities charges are marginal costs only in a general economic sense in that they reflect the cost of the next streetlight. These charges, however, bear no relation to the production, transmission, or distribution of electricity change and therefore have no relation to the change in Edison's output. In staff's view, these charges are merely rental or usage charges associated with Edison providing an appliance service and as such should be excluded from marginal cost applications including revenue allocation.

The staff, however, does not advocate excluding the street light group completely from the revenue allocation process. Specifically, the staff asks the Commission to reconsider its decision in PG&E's most recent general rate case authorizing such an exclusion. The staff concedes that streetlighting customers possess a great many characteristics that set them apart from other customers. Their usage pattern is generally flat, mostly mid- and off-peak and rarely on peak. Some of their own facilities and some rent from Edison. However, it is precisely because of these characteristics that there is a separate streetlight customer group. The staff believes, therefore, that once the facilities charges are removed from the revenue requirement and marginal cost-based allocations are performed, which by their very nature take into account the voltage level, load factor, and time-of-use characteristics of the customer group, there is no need to consider streetlighting to be any different for allocation purposes than any other group.

Cal-SLA responded to this argument in its reply brief. According to Cal-SLA, all customer groups have certain characteristics that warrant placing them in separate classes. It is Cal-SLA's point, however, that for revenue allocation purposes, all customer groups other than streetlighting have certain common characteristics (e.g., load characteristics, metered service, no appliance owned and maintained by the utility) entirely distinct from the street lighting class. This distinction, in Cal-SLA's opinion, warrants separate treatment of street lighting customers in the revenue allocation process. Cal-SLA also asserts that staff's approach of excluding facilities charges, but including other street lighting costs in revenue allocation, does not achieve a simple straightfoward method of rate design understandable to the street lighting customer.

We concur with Cal-SLA. The unique characteristics the street lighting group recited by Cal-SLA and noted by this Commission in D.83-12-68 (PG&E rate case) support continuing a policy of excluding the street lighting group entirely from a marginal cost revenue allocation process. We find Edison's explanation of why a facilities charge is not a customer cost somewhat strained and not necessarily in keeping with the testimony of their own witness. For the reasons set forth by Cal-SLA, the streetlighting class will not be subject to marginal cost revenue allocation. Consistent with our past pratice for the streetlighting class, we will allocate the base revenue decrease authorized in this decision on a SAPC basis and the revenue increase authorized today in the MAAC offset proceeding (A.82-02-40) on an equal ¢/kwh basis.

2. Schools Committee to Reduce Utility Bills (SCRUB)

SCRUB requests a separate revenue allocation aproach for schools. Specifically, SCRUB proposes that the Commission allocate revenue responsibility to schools on the basis of what it would cost schools to generate their own power. This approach starts with the assumption that, with the Commission's use of marginal costs, schools are paying a disproportionate share of Edison's revenue and might actually save money by generating their own power. In addition to arguing that its approach will lead to rates more accurately reflecting Edison's cost of serving schools, SCRUB asserts that the continuation of high utility rates for schools and other commercial customers will lead to a loss of those customers. SCRUB also argues that the current marginal cost approach to revenue allocation does not adequately recognize that schools' greatest energy consumption is in the nonpeak period. Finally, according to SCRUB the public will benefit by lower school utility bills since such billing reductions will cause the release of dollars for education or for capital improvements for conservation.

Edison asks that SCRUB's proposal be rejected. Edison argues that SCRUB's proposal violates the very essence of the ratemaking process. According to Edison, the purpose of this process

is to develop rate levels which will recover the utility's cost of service and not the projected cost at which a customer believes that he may be able to produce energy.

Similarly, the staff objects to SCRUB's proposal. The staff states that it is opposed to any "special" rate which is, in the staff's view, the essence of SCRUB's request. Staff notes that when a special rate is arranged for one group of customers, the revenue saved by that special group is recovered elsewhere.

We agree with both staff and Edison. SCRUB's proposal would not only require this Commission to single out schools from other customers without adequate cause, but would also require us to develop rates for schools based on an approach contrary to basic ratemaking principles and our present policies. We find insufficient evidence to justify the special treatment sought by SCRUB, and we reject SCRUB's proposal for rates based on a school's cost of generating power.

C. Adopted Revenue Allocation

Table 2 reflects our findings above. The table sets forth our adopted revenue allocation using the 95% SAPC - 5% EPMC approach.

TABLE 6
ADOPTED REVENUE ALLOCATION
SOUTHERN CALIFORNIA EDISON COMPANY
1985 TEST YEAR GENERAL RATE CASE
(Revenues in Thousands $)

Revised 12/24/84

CUSTOMER CLASS	SALES (GWH)	REVENUE AT PRESENT RATES a/ BASE	OFFSETS	EFFECTIVE	MARGINAL COST RATES (¢/kWh)	MARGINAL COST REVENUE	ADOPTED EFFECTIVE REVENUE b/	EFFECTIVE RATE CHANGE (%)
Domestic	18294.3	830133.5	551010.1	1381143.6	8.97	1640998.7	1437942.6	4.11
Lighting, Small & Medium Power	19686.2	881758.2	759122.8	1640881.0	9.64	1897749.7	1706034.7	3.97
Large Power	19422.3	702619.2	747932.4	1450551.6	8.44	1639242.1	1506425.6	3.85
Agricultural and Pumping	1800.8	71331.1	69041.8	140372.9	9.24	166393.9	146128.2	4.10
Subtotal Marginal Cost Classes	59203.6	2485842.0	2127107.1	4612949.1		5344384.4	4796531.1	3.98
Streetlighting	453.4	50379.9	17483.0	67862.9			68464.1	0.89
Subtotal Five Major Classes	59657.0	2536221.9	2144590.1	4680812.0			4864995.3	3.93
Firm	7.0	297.6	251.7	549.3			571.0	3.93
IID	0.0	6.5	0.0	6.5			6.5	0.0
Other Oper. Revenue	0.0	27814.0	2664.0	30478.0			30478.0	0.0
Total CPUC Jurisdictional	59664.0	2564340.0	2147505.8	4711845.8			4896050.8	3.91
Resale	4588.0	133692.0	233745.0	367437.0				
Total System	64252.0	2698032.0	2381250.8	5079282.8				

a/ Rates as of 11/21/84 with AMAR revenues rolled into base.
b/ Net Revenue Increase of $184,205,000: Base revenue decrease of $115,795,000 spread by weighted average of 95% SAPC - 5% EMC to marginal cost classes; SONGS revenue increase of $300,000,000 spread by SAPC except allocation to streetlighting on an equal cents per kWh basis.

D. Intervening Offset Proceedings

Another issue related to revenue allocation is the methodology to be used in allocating revenue increases occurring between rate cases. The significance of this issue has, of course, been heightened by our adoption of a three-year period between a utility's general rate cases.

In D.83-12-068 (PG&E general rate case), we discussed the three logical methods of allocating offset revenue changes to the customer classes. These methods included the traditional equal cents per kilowatt-hour approach (¢/kWh), the approach adopted in the general rate case (EPMC), and an approach using an equal percentage rate change. (D.83-12-068, at p. 366.)

In discussing these available methods, we rejected the equal ¢/kWh approach. Although used by the Commission in the past, we found that this approach did not reflect total marginal costs and that in turn the relationships between customer groups established in the general rate case proceeding could become distorted especially if the offset revenue changed greatly. The EPMC method was also rejected because rate design and calculation issues raised during the general rate case might arise again in the offset proceedings. We stated our desire that offset cases not become the forum for rate design. (D.83-12-068, at p. 368.)

The method which we did adopt was the System Average Percentage Change (SAPC) method. We found this method simple and uncontroversial. Further, because this method reflected marginal costs, it would maintain the class relationships established with marginal cost principles in the general rate case. We also concluded that it could be applied to rate decreases as well as rate increases in any type of offset proceeding.

In this proceeding, however, the SAPC method has not been uncontroversial. Both Edison and GM/Union Carbide assail this method and urge a return to an equal ¢/kWh approach. The FEA recommends the EPMC method, while only the staff, primarily in reliance on our

decision in PG&E's general rate case, recommends following the SAPC method. In the opinion of Edison and GM/Union Carbide, the evidence presented by Edison in this proceeding demonstrates that the rationale used by the Commission to justify its adoption of the SAPC in PG&E's general rate case is unfounded. Specifically, these parties argue that this testimony reveals the failure of the SAPC methodology to preserve the marginal cost-based rate relationships established in the general rate cases for energy-related rate changes occurring between general rate cases. These rate changes are described by GM/Union Carbide as "the lion's share" of the revenue changes which occur between Edison's general rate cases.

According to Edison, there is no evidence in this record that demonstrates that the SAPC methodology maintains cost relationships between customer groups. Edison asserts that both marginal and real energy costs are directly related to energy sales and are in no way related to percentages of revenue on which the SAPC method focuses. Under the equal ¢/kWh method favored by both Edison and GM/Union Carbide, however, energy is valued at any given time at substantially the same cost for all users with the minor exception of line losses. In Edison's view, adoption of the SAPC methodology for ECAC rate changes will result in a misallocation of revenue and a resulting inaccurate price signal to customers.

Edison is also of the opinion that the equal ¢/kWh method is preferable for allocating over- and undercollections in the various balancing accounts. Edison notes that by using the equal ¢/kWh method as it has been in the past an overcollection will be returned to customers on the same basis on which it was paid.

Edison also contends that the staff made two erroneous assumptions with respect to the application of the SAPC methodology. Edison first asserts that the staff erroneously assumed that application of the SAPC methodology would not cause any customers to transfer from one rate schedule to another. According to Edison, staff failed to perform any analysis of whether the relationship

between rate schedules would be changed by application of the SAPC methodology to intervening offsets. In contrast, Edison performed a customer transfer analysis which in Edison's opinion clearly demonstrates that customers would transfer between rate schedules solely due to an interim revenue allocation which might change the original relationships between rate schedules.

Second, Edison states that staff erred in assuming that the billing determinants and resulting revenues would not materially change between rate cases. In support of its position, Edison cites the increase of 7.6 percent and 8.3 percent in kilowatthour sales to the Domestic Customer Group and Edison's Lighting and Small and Medium Power Customer Group, respectively, and a decrease of 5.7 percent in sales to the Agricultural and Pumping Customer Group between Edison's 1983 general rate case and its current ECAC filing. According to Edison, these figures demonstrate that between general rate cases material changes can occur in kilowatthour sales and resulting billing determinants, all of which result in commensurate changes in base rate revenues, the basis for the SAPC methodology. Application of the SAPC methodology in an offset proceeding would therefore result in retaining only the then existing relationships between customer groups and not necessarily the relationships between customer groups established in the general rate case proceeding.

Edison also objects to the use of the EPMC methodology approach for allocating revenue increases or decreases between general rate cases. Edison argues that the EPMC methodology should be rejected because the equal ¢/kWh tracks costs and the EMPC approach would not be practical in expedited offset proceedings. With respect to Edison's latter point, Edison explains that if the EMPC methodology were used, marginal energy costs would have to be computed in each offset proceeding in order to maintain the marginal cost relationships used in applying EPMC. Edison argues that this circumstance would require the examination of marginal costing and

rate design issues in offset proceedings and would thereby tend to erode the expedited nature of these proceedings.

As we stated previously, our adoption of the SAPC methodology in PG&E's most recent rate case was based on three premises--the SAPC approach was (1) simple, (2) uncontroversial, and (3) capable of maintaining the class relationships established with marginal cost principles in the general rate case. In this case, while Edison and others challenge staff's recommended SAPC, as shown in Exhibit No. 133, we find it consistent with our approach in D.83-12-065 for SDG&E and D.83-12-068 for PG&E.

The ratemaking principle we adopted in those decisions and in D.82-12-113 establishes that the effective class rates, the composite of both base and offset components, will bear the same proportional relationships to one another as do their respective marginal costs. The EPMC allocation which we will apply in this case will accomplish this goal. However, the proportional relationships between class rates would not be maintained by future equal cent adjustments as proposed by Edison. What Edison has succeeded in demonstrating is that class rate relationships may change due to future offset rates which could materially differ from those adopted in this general rate case. This result is a potential problem with either the SAPC or equal ¢/kWh. However, we do not wish to exacerbate this problem by utilizing an allocation method (equal ¢/kWh) which in and of itself produced departures from a marginal cost proportioned rate structure.

Further, Edison states that it is concerned that customers in a narrow band of usage (spanning 16 kWh per month) would have some incentive to switch between GS-1 and PA-1 rate schedules given a billion dollar system revenue increase spread by the SAPC method. We consider this impact of using the SAPC method to be very minor

Additionally, as we have stated before, the issue of customer migration can always be addressed by appropriate modifications of the applicable tariffs. We therefore adopt the SAPC allocation for subsequent Edison offsets for those customer classes for which marginal costs have been adequately developed and utilized as a revenue allocation principle in this general rate case. We will also maintain proportional relationships within those customer classes. With respect to the street lighting class, however, we recognize that this class has unique revenue obligations associated with special facilities, the cost of which may not change proportionately with changes in the systems overall revenue requirement. We will therefore maintain the equal cent offset adjustment for street lighting only.

E. Present Rate Revenues

Edison recommends that present rate revenues should be developed based upon rate levels estimated to be in effect in the test year, absent the revenue changes the Commission will authorize in this general rate case. In contrast, staff believes that present rate revenues should be based upon rate levels actually in effect immediately prior to any change in revenue level authorized in this decision.

Edison believes that its method is needed to assure consistency between marginal gas fired generation costs in this case and gas price assumptions in future ECAC cases. Edison's explanation of these points is unclear. However, to the extent we have adjusted estimated gas prices to be utilized in developing marginal energy costs to closely reflect more recent ECAC case expectations, Edison's concerns should be obviated.

The ultimate outcome of Edison's recommended present rate revenue definition and allocation technique is shown in Exhibit 133. Edison builds an EPMC revenue allocation from a present and proposed revenue assumption of $500 million in excess of what will be authorized in this case to anticipate a future ECAC increase. If, and only if, the ECAC increase materializes as anticipated by Edison, will class rates bear the same proportional relationships to one another as their respective marginal costs. The staff method based on present rate revenues (those in effect at the time rates are changed), however, will produce the desired result under any future revenue authorization. If given perfect assumptions, the outcome is the same, we fail to see any theoretical or practical benefit in Edison's proposal. We will therefore maintain the definition we have used in the past: present rate revenues will be based on rate levels actually in effect just prior to any change in revenue level authorized in this proceeding.

XIII. RATE DESIGN

Both Edison and the staff have adopted principles to guide them in making their respective rate design proposals. The principles adopted by Edison have been previously enumerated and include recovery of revenue requirement, marginal cost, revenue stability, conservation of electrical energy, load management, baseline allowances and baseline rate level, and rate history and customer acceptability. Staff emphasizes (1) the need to continue the Commission's basic policy of basing rates on marginal costs, (2) the implementation of baseline in a manner designed to keep the new rates and allowances as close as possible to those established under the lifeline program, (3) the avoidance of any favoritism of a particular ratepayer or group of ratepayers, and (4) the absence of exemptions from mandatory time-of-use rates.

Although staff concurs with the rate design principles recited by Edison, staff questions Edison's commitment to those principles. In particular, staff argues that Edison's proposals more often reflect a greater concern with preventing customer migration between rate schedules than adhering to marginal costs. The staff recognizes that customer migration may be a problem, but argues that the perpetuation of existing class relationships alone may not always be good rate design policy.

Edison asserts that staff failed to demonstrate the propriety of its rate design since none of the staff witnesses offered a rate design which would recover a revenue requirement. In order to evaluate the staff's proposal, Edison states that it attempted to design rates which followed as closely as possible the staff's proposed rate design criteria and procedure. These efforts resulted first in Exhibit 133 and, after staff objections to that exhibit, late-filed Exhibit 143. Edison asserts that during discussions held in the course of the development of Exhibit 143,

"staff explained what they really meant as opposed to what was set forth in the record" and made certain adjustments in their rate design.

The staff strenuously objects to this characterization of its participation in this case or in the preparation of Exhibit 143. Staff asserts that Exhibit 143 conforms with the methodology to which staff testified during the proceeding and, in this regard, was an improvement over Exhibit 133. Staff also notes that it continues to lack the in-house capability to undertake a full rate level development of its rate design and has been forced therefore to rely on the utility for necessary data and computer services. Staff still finds Exhibit 143 less than satisfactory since it reflects Edison's definition of present rate revenues. Staff also disassociates itself completely from the customer transfer representations made in either Exhibit 133 or 143.

It is obvious that the issue raised by staff's questioning Edison's dedication to Edison's rate design principles relates to the impropriety of focusing on only one such principle in adopting a particular revenue allocation methodology or rate design. We assure the staff and all parties to this proceeding that every aspect of any rate design proposal and its consistency with stated Commission policy and accepted ratemaking principles will be considered in our decision to adopt or reject such a proposal.

We also reject Edison's attempt to discredit the staff's rate design testimony in this case. The staff did in fact make a rate design proposal in the hearings which has been, with Edison's currently required assistance, translated into actual rates. In reviewing the rate design proposal of the staff, we will take into consideration staff's noted exceptions to Exhibits 133 and 143.

A. Residential Rate Design

1. Baseline Allowances

In this proceeding, we are required to implement legislation enacted in 1982 affecting Edison's residential rate design. This legislation (AB 2443, Stats 1982, Ch. 1542) revises Public Utilities (PU) Code § 739 by replacing lifeline quantities of electricity for residential customers with baseline quantities. Baseline is similar to lifeline in that it provides a monthly quantity of energy at a rate lower than the system average rate. It differs from lifeline in that the quantities are based on the average consumption pattern of customers in similar climate zones, rather than on specific end uses.

Baseline quantities are to be set at 50-60 percent of average residential consumption with certain seasonal adjustments for all-electric customers. These quantities are to be priced 15-25 percent below the system average rate and are to apply to the first block of an increasing block structure. Section 739 provides for electric customers to be differentiated by climate zone, by season (summer-winter), and by customer (all-electric customers, including space heating, or non-all-electric customers).

The climate zones proposed by Edison and the staff differ from those which have been used for lifeline. The recommended climate zones are based on the statewide climate zones established by the CEC which were adopted by the Commission in the most recent PG&E and SDG&E general rate case decisions.

Edison and the staff are in agreement with respect to (1) the climatic zones for which baseline allowances are to be determined, (2) the recovery through rates of the costs associated with implementing the baseline structure, (3) the basic baseline allowances and (4) the implementation of baseline through the use of daily rates. In arriving at recommended baseline quantities, staff

looked at the full range of allowances permitted by the AB 2443. One of staff's goals was to select quantities that were not significantly different than lifeline quantities, if possible. The staff has therefore recommended the maximum baseline allowances for 7 of the 12 summer climate zone categories, for winter all-electric customers (70 percent of average usage), and for winter non-all-electric customers in one of the climate zones (60 percent). The balance of the climate zones and seasonal allocations would be based on 55 percent of average usage.

We find reasonable the basic baseline approach described above with the requirement that staff's method of rounding during arithmetical computations be used. This conclusion alone, however, does not resolve all of the issues related to the implementation of baseline--several important ones remain. These include not only the actual commencement of baseline, but also disputes between Edison and staff relating to the handling of Climate Zone 15 (which includes the Coachella Valley), the extension of baseline to residential hotels, and the proration procedure to be used for seasonal baseline changes.

a. Commencement of Baseline

In its testimony, staff recommended that the conversion from lifeline to baseline occur in May, 1985, to coincide with the change from winter to summer billing periods. Originally, Edison concurred with this date. During the course of its rebuttal testimony, however, Edison stated that additional studies indicated that a large number of customers would experience dramatic seasonal and/or annual rate increases solely due to the conversion from lifeline to baseline, even in the absence of a rate increase. In response to this circumstance, Edison submitted late-filed Exhibit 146 to indicate the areas affected by such an increase and to present a plan for the phased implementation of baseline.

According to Exhibit 146, Edison determined that even without a rate increase three basic categories of customers would receive substantial increases solely as a result of the conversion to baseline. The specific impact on these customers is described in Exhibit 146 as follows:

- Customers who currently have winter space heating lifeline allowances will receive maximum increases of 10 to 20 percent.
- Customers who currently have water heating lifeline allowances will receive maximum increases of 10 to 30 percent.
- Selected gas water heating and gas space heating customers who have summer air conditioning lifeline allowances will receive maximum increases of 15 to 25 percent.

Based on the results of its analysis, Edison concluded that more than 235,000 or eight percent of its domestic customers would be adversely impacted through higher billings by the implementation of baseline quantities on an annualized basis.

It is Edison's opinion that the negative impact of implementing baseline in a single step can be moderated by phasing in baseline quantities over a two-year period commencing in May, 1985. The proposal would incorporate the following limitations:

- No customer would receive a larger interim allocation above his current lifeline allocation if that customer were to ultimately receive a lower baseline quantity.
- A conversion from lifeline climatic regions to baseline zones would occur in May of 1985.
- No additional lifeline end-use classifications would be implemented.
- New domestic customers who are added to the Edison system between May of 1985 and May of 1986 would be permitted to specify a specific end-use classification which would qualify such customers for the interim baseline quantities.
- The calculation methodology employed by Edison assumes that in the interim period approximately 55 to 60 percent of total Edison kWh sales for the domestic group would be billed at baseline rates, thus maintaining an approximate total kWh relationship between lifeline allowances and baseline quantities.

Although Edison did not recommend a longer phase-in period, a similar approach using a three-year phase-in was developed. Edison's proposed baseline quantities for both a two-year and a three-year phase-in implementation are set forth in Exhibit 146.

Exhibit 146 also contains the staff's comments on Edison's proposal. The staff believes that the exhibit actually reveals that the seasonal and annual impact of baseline on any one customer will actually be less than on a monthly basis which had been examined in a previous exhibit. Specifically, staff notes that although a customer might have a maximum monthly increase of up to 34 percent due to the implementation to baseline, the customer's cumulative annual increase would not exceed 24 percent.

Nevertheless, the staff agrees with Edison that implementing baseline in a single step will have a severe impact on Edison's domestic customers. Staff therefore joins Edison in recommending at least a two-step phase-in of baseline be adopted. In addition to the phased-in approach, staff recommends placing a "cap" on the maximum kWh decrease in allowance that a customer could experience at any one time. Staff suggests that the cap be set at 200 kWh to ensure that the effects of baseline implementation would be limited to less than a $6 per month increase in any one year.

According to the staff, should the Commission adopt a two-step phase-in with a 200 kWh cap, 59 of a total 76 lifeline to baseline categories would be at their final baseline allowances by the end of the two-step process with 12 categories requiring an additional step and 5 requiring two additional steps. If a three step proposal with a 200 kWh cap were adopted, 71 categories would reach their final baseline allowance by the end of the three steps and only 5 categories would require an additional step.

We believe that in addition to being mandated by the legislature, the baseline concept is a viable, appropriate, and superior approach to the previous lifeline end-use concept. This year, however, with the implementation of baseline in PG&E's service territory, we have learned first-hand of the often negative effects which the conversion from lifeline to baseline can have for many customers. The evidence presented by Edison and the staff in this proceeding suggests that a similar result for Edison's residential customers is inevitable.

While we are obviously required to implement baseline in accordance with PU Code § 739, we believe that our non-legislative duty will be met and Edison's ratepayers better served by our adopting a phased-in implementation of baseline. Using Edison's approach, baseline would be fully implemented within the three-year period covered by this decision and before its next test year. Additionally, and most importantly, the effects of the conversion from lifeline to baseline would appear to be significantly mitigated for most customers.

We still share, however, staff's concern for those customers, however few, that would be severely impacted even under a three-year phase in approach. We will therefore adopt Edison's alternate three-year phase-in approach as set forth in Exhibit 146, modified to include a 200 kWh cap on the amount of the decrease which could be experienced by any of Edison's customers in a single year. In addition to the staff's recommendation for a 200 kWh cap, we will also order Edison to classify all customers who are presently being billed with an electric water heating allowance as all-electric customers as we did in D.84-11-026 for PG&E.

The baseline quantities for Edison's service territory are recited in Appendix C of this order. This appendix reflects the phase-in implementation of baseline adopted herein.

b. Climate Zone 15

Climate Zone 15, as defined by staff and Edison, is an area which includes the Coachella Valley (Palm Springs, Palm Desert, and a number of other desert communities), Blythe and its vicinity, and Death Valley. The issues relating to Climate Zone 15 center on differences between Edison and the staff with respect to the appropriate baseline allowances for the zone and the concerns of the Coachella Valley Association of Governments (CVAG).

For all climate zones, Edison has proposed a six-month winter season and a six-month summer season for baseline allowances, with separate allowances for all-electric customers and for non-all-electric customers as required by PU Code §739. Alternatively, Edison proposes baseline quantities utilizing a four-month summer period and an eight-month winter period. Edison's methodology used in developing both its primary and alternative approaches is the same and mirrors the methodology which the staff used in developing its six-month summer and six-month winter baseline quantities.

While proposing the six-month summer and six-month winter periods for other climate zones, the staff recommends a reallocation of the annual baseline kWh for Climate Zone 15. Specifically, staff proposes that the summer baseline quantities for the months of June, July, August, and September be established at 1200 kWh with the winter quantities established at a level which equally spreads the remaining annual total to the eight winter months.

Edison urges the rejection of the staff's proposal for a number of reasons. First, Edison asserts that the staff's proposal does not include separate baseline allocations for all-electric customers and non-all-electric customers, as required by PU Code § 739. Second, Edison charges that the staff assumption of customers using a greater part of the annual baseline quantity during the four summer months was merely an approximation. In contrast, Edison asserts that its baseline quantities were based on a frequency distribution.

Edison also states that its Exhibit 146 demonstrates the following:

- When viewed on an annual basis, Edison's proposed six-month winter/six-month summer baseline quantities for Climate Zone 15 result in a decrease or no change in the bills of approximately 80 percent of Zone 15 customers. The remaining 20 percent of Zone 15 customers would receive annualized bill increases of zero to $110.
- Utilizing Edison's alternative four-month summer/eight-month winter approach, approximately 85 percent of Zone 15 customers would receive a decrease or no change in their bills on an anual basis. The remaining 15 percent of Zone 15 customers would receive annualized bill increases of zero to $110.
- In contrast, staff's proposed four-month summer/eight-month winter baseline quantities result in a decrease or no change in the bills of only 40 percent of Climate Zone 15 customers, with the remaining 60 percent receiving annualized increases in their bills of up to $150.

Staff asserts that Edison is incorrect in stating that staff's proposal does not include separate baseline allocations for all-electric customers and non-all-electric customers. The staff

states that it did establish different winter allowances for these two customer groups where major differences occur due to heating needs; only summer levels were equal.

Although acknowledging that its approach for Climate Zone 15 is not technically as "pure" as its determination of baseline allowances for the other climate zones, staff believes that its approach addresses the zone's need for increased baseline quantities in the summer while keeping within the limits of the law. The staff notes that its approach will not result in Climate Zone 15 residents having any more kWh of baseline allowance on an annual aggregate basis than they would if Climate Zone 15 had the same seasonal distribution used in other climate zones. With the redistribution, however, Climate Zone 15 customers would experience little change from the 1140 kWh per month lifeline quantity available in the summer to essentially all-electric customers.

In its comments to Exhibit 146, staff states that Edison's tables suggest that Edison's proposal has more beneficial and less negative impacts than the staff's approach. Staff, however, continues to support its approach noting that Edison's proposal would reduce the allowance for three out of four summer and two out of four winter lifeline end-use categories. The staff asserts that, in contrast, its proposal would increase the allowances for all four summer and one winter category and would allocate more kWh annually to both the all-electric and non-all-electric customers than would Edison's approach.

With respect to CVAG, the concerns of this organization were largely expressed in a complaint which it filed against Edison (Case (C.) 83-05-10) and in its comments at the Public Hearings held in Palm Desert on April 18, 1984. In its complaint, CVAG requested an increase in lifeline allowances in the Coachella Valley and a study to determine the effect of seasonal residency on usage patterns in the area. In D.84-02-064, the Commission directed

Edison to conduct a study within 120 days of the effective date of the order to determine the effects of seasonal customer residency on average residential usage within its system. On June 8, 1984, this filing date was extended by ALJ ruling until 120 days after a decision on Edison's petition for modification of D.84-02-064. The petition requests the modification of D.84-02-064 (1) to provide a definition of "seasonal residents" for purposes of the study, (2) to define the scope and cost of the study, and (3) to provide for recovery in rates of the cost of the study. As of the date this proceeding was submitted, the Commission had not acted on Edison's petition.

During the Public Hearing, the CVAG Executive Director renewed CVAG's request for larger allowances and the study. Additionally, he also raised concerns regarding the climate zone in which Coachella Valley had been included. Recognizing that baseline allowances are based on usage within each climate zone, CVAG noted that the Coachella Valley was hotter in the summer than any other area in the state, but that it had been included in a climate zone with three separate areas in it.

Both staff and Edison have responded to CVAG's statements by noting that they have both made proposals which not only follow the established guidelines for determining baseline quantities, but provide the seasonally varying baseline quantities sought by CVAG. These proposals include staff's Climate Zone 15 proposal and Edison's alternative four-month summer/eight-month winter baseline quantities.

The staff and Edison also defend their proposed climate zones. Edison states that the climate zones are based on the California Energy Commission climate zones which were developed after an extensive climatological study by the CEC. These zones were also used for PG&E and SDG&E. Further, staff asserts that the areas included with Climate Zone 15 have comparable thermal conditions.

In reviewing the record in this case, it is apparent that both Edison and the staff have sought to respond to the special needs of Climate Zone 15 residents. We believe that these needs can be adequately met at the present time by adopting both the climate zone proposed by staff and Edison and the baseline quantities proposed by staff utilizing its four-month summer/eight-month winter approach. We are not convinced that Edison's proposed Climate Zone 15 baseline quantities adequately address the areas need for increased baseline allowances in the summer. In fact, the Edison four-month summer/eight-month winter proposal results in a lower annual baseline quantity than its six-month summer/six-month winter proposal. Although the staff's approach is not technically as "pure" as that used for other climate zones it does not decrease the annual quantities while recognizing the higher summer needs.

With respect to the study requested by CVAG, Edison correctly states that it has been granted an extension of the original filing deadline. Upon issuance of our decision on Edison's petition, however, the study will be due, as directed by the ALJ, within 120 days.

c. Baseline for Residential Hotels

In this proceeding, staff has recommended that baseline allowances be made available to residential hotels in the Edison territory. Staff asks that this extension of baseline be accomplished in the same manner as prescribed for PG&E in its most recent general rate case decision (D.83-12-068). In staff's opinion, the basis for qualifying for baseline should be the same for all utilities.

Edison voices several objections to residential hotels receiving baseline allowances. First, Edison states that there is no demonstrated need for such an extension in its service territory. Second, individual tenants within residential hotels cannot be charged directly for their electric service and cannot be guaranteed that the benefits of baseline will be flowed-through to them by hotel owners.

Equally important in Edison's view is the fact that, under Edison's current definition of domestic service, residential hotels may not be considered residential customers. Further, if residential hotels were included in that definition, there would be no basis to deny a similar right to boarding houses or dormitories. Edison also believes that granting baseline quantities to residential hotels would be inconsistent with Commission policy requiring submetering of multifamily accommodations.

If baseline is extended to residential hotels, Edison urges one of two approaches. In Edison's opinion, the hotels must be required to physically separate their electrical service between that supplied for domestic purposes and that supplied for commercial purposes. Alternatively, the residential hotel should be required to meet Edison's current tariff definition of domestic service which limits such service to premises where non-domestic connected load does not exceed 300 watts for lighting or 2 hp for power.

In D.83-12-068, PG&E and the staff had also objected to the extension of baseline allowances to residential hotels. Like Edison, these parties had argued that there was not a viable definition which would permit only residential hotels, as opposed to all hotels, to receive the baseline allowance. We responded, however, that the definition of multifamily dwelling which

we had adopted for two conservation programs could serve as an appropriate definition. It was our opinion that a residential hotel should be treated no differently than multi-unit apartment dwellings which qualified for lifeline allowances. We stated that it was our goal that eventually both types of dwelling units, residential hotels and multi-unit apartments, would be individually metered.

We therefore found it reasonable to extend the baseline allowance to a residential unit where at least 50 percent of the units are leased for a minimum period of one month and are occupied for at least nine months of the year. PG&E was directed to file a plan to implement a baseline allowance for such units, to identify the dwellings in their service territory which could be defined as residential hotels, and to indicate the extent PG&E intended to coordinate its plan with local governments and organizations. (D.83-12-068, at pp. 372-373.)

We believe that this approach is equally applicable to Edison. The administrative burdens on Edison, if any, are not different than they are for PG&E. While we cannot guarantee that rate reductions will be flowed through from owner to tenant, we do know that application of baseline to residential hotels will reduce the cost of operating such a premise. We believe that it is appropriate to take whatever steps are available to permit all residents the opportunity to realize, to the extent possible, the benefits of baseline.

We therefore will extend the baseline allowance to residential units in Edison's service area as that term is defined in D.83-12-068. Similarly, Edison will be directed to file a plan for applying baseline allowances to residential hotels, for identifying residential hotels in its service territory, and for coordinating its efforts with local governments and organizations. In recognition of one of Edison's concerns, however, we will permit Edison to include

in its plan an indication of the percentage of residential hotels which would in fact fall within its current definition of domestic service. Edison may also comment on the feasibility and the costs associated with a residential hotel segregating its electric service between that supplied for domestic purposes and that supplied for commercial purposes.

d. Prorationing

Based on studies available at the time, the staff originally took exception to Edison's proposal to continue its current practice of prorating the transition between seasonal baseline allowances. The staff proposed that the Commission should instead implement a no-proration procedure for seasonal baseline changes consistent with recent Commission decisions involving PG&E, SDG&E, and the Southern California Gas Company. It was staff's opinion that this change to a no-proration procedure would have no different impact on overall revenues than Edison's approach. Further, staff noted that Edison's prorationing procedure was similar to the "McKinney method" of prorationing which the Commission had found to be biased against customers under certain circumstances.

To implement its no-proration procedure, staff recommended the following:

> "May 1 is the transition date from winter to summer lifeline allowances. A reasonable way to initiate the no-proration method is to start the summer lifeline allowance on a billing period for meters read on May 16. Thus all bills rendered for meters read on May 16 would have a summer lifeline [baseline] allowance for that bill and the next five bills. The next six bills would have a winter lifeline allowance." (Exhibit 53, p. 3-6.)

It was Edison's position that staff's approach had numerous flaws and that, based on later studies contained in its rebuttal testimony, no-prorationing would have an adverse revenue

impact on customers. Edison states that a no-proration approach (1) does not provide for equity between customers, (2) does not follow weather patterns and customer consumption patterns, (3) violates baseline rate design principles, (4) results in increased billings to Edison's customers, and (5) causes customer confusion by having a no-proration procedure for baseline changes and a proration procedure for rate changes.

Based on Edison's rebuttal testimony, which contained studies previously unavailable to the staff, staff states in its opening brief that it no longer objects to Edison's prorationing proposal. Among other things, staff agrees that its no-proration method would have an adverse impact on Edison customers in terms of a net increase in their bills.

We similarly find that Edison's later studies, combined with its proposals to move from monthly to daily baseline allowances, provide strong support for continuing Edison's current prorationing procedure. We now have completed one seasonal baseline transition for PG&E using a no-proration approach. Instead of a reduction in customer complaints due to the implementation of this approach, we have found significant customer dissatisfaction. This dissatisfaction has been caused by abrupt changes from the winter to summer seasonal allowances which have resulted in a reduced baseline quantity without a corresponding climatic change.

Although a "long winter" may not occur every year, the potential for such climatic conditions, the results of Edison's study and Edison's implementation of daily baseline allowances persuade us to continue Edison's current prorationing practice. The change from monthly to daily rates will simplify the prorationing calculation and in turn should enhance customer understanding of the procedure. Further, prorationing will eliminate the negative impact of a customer bill increase which would otherwise occur with a no-prorationing approach. We therefore adopt Edison's prorationing method for seasonal baseline changes.

2. Residential Rate Design

Both Edison and staff recommend that the Commission maintain Edison's current two-tier residential rate design. The parties differ, however, as to the rate levels of these two tiers. Staff proposes that the baseline rate (first tier) should be set at approximately 80 percent of the system average rate with the second tier rate being set approximately 48 percent higher. Staff believes that this approach is in keeping with the statutory requirement that the baseline rate be set at 15 to 25 percent less than the system average rate. (PU Code § 739(c).) Between rate cases, the staff recommends that the baseline rate levels be kept within legislative limits, but as close to the 80 percent of system average rate level as possible without creating too great of a spread between the two tiers.

In contrast, Edison has recommended an 85 percent of system average rate for baseline, the highest baseline rate allowed under PU Code § 739. This rate was selected by Edison "in order to set the domestic non-baseline levels such that domestic customers will not be encouraged to migrate to non-domestic rate schedules, such as GS-1." (Ex. 10 at p. VI-13.)

Staff asserts that Edison's reasoning in support of its rate design proposal reflects Edison's singular concern with customer movement between rate schedules. In staff's opinion, this concern is better addressed by the adoption of restrictive tariff language, rather than by adjustments of rate levels. Staff notes that PG&E has adopted restrictive tariff language which has limited customer migration between schedules to less than 1 percent of total residential sales.

We concur with the staff. Any significant problem created by customer migration was not sufficiently documented by Edison during the hearings. Further, it appears that this problem can be adequately addressed by adopting tariff language to limit such changes.

We therefore adopt staff's proposed two-tier residential rate design. As suggested by staff, the adopted percentage governing the rate levels in each tier should be maintained, to the extent possible, between Edison's general rate cases. Should the problem of migration become significant, we believe that Edison can and should present an advice letter filing proposing the addition of appropriate restrictive tariff language.

One last issue relating to residential rate design concerns the existence of lifeline quantities and rates for the first several months of the test year. As stated previously, the first phase of baseline implementation will not commence until May 1985. For the period when lifeline rates will still be in effect, we adopt the staff's recommendation that the residential rate spread in effect prior to January 1, 1985 be used. Any increase or decrease in residential class revenues resulting from this decision will be allocated to lifeline and non-lifeline tiers on a straight percentage basis maintaining their current relationship.

3. Residential Time-of-Use Rates (Schedule TOU-D)

Our discussion of residential time-of-use (TOU-D) rates in this section is limited to the rate design to be adopted for the TOU-D schedule. The staff maintains that the schedule should be "rate neutral" with residential Schedule D for average on-peak usage. To the staff, rate neutrality means that a customer would not experience any savings by migrating from Schedule D to the TOU schedule unless the customer already used (or shifted load to) less than 23% on-peak usage. Staff argues that Edison's proposed TOU-D schedule would not be rate neutral, but would allow high usage customers with low lifeline or baseline allocations to obtain a rate reduction merely by switching schedules.

In order to achieve complete rate neutrality, staff proposes that the TOU-D schedule take into account the two tiers used for Schedule D. The appropriate baseline allowance to Schedule TOU-D would be allocated between 23% on-peak and 77% off-peak usage. The on-peak rates would not be seasonally differentiated because of resulting customer confusion and the potential for impeding customer recruitment for the schedule. The staff therefore recommends that the on-peak rates be non-seasonal and set to equal the weighted average on-peak marginal cost. Staff believes that for its two-tier TOU-D rate design it is also appropriate for the on-peak rates to be weighted by baseline to non-baseline sales.

Finally, staff takes exception to Edison's proposed "customer charge" of $5 per meter per month for the TOU-D schedule. Staff asserts that this charge should be a $2.50 meter charge representing approximately one-half the cost of the additional metering required under the schedule. By recapturing half of the additional meter cost, the staff believes that the participant and non-participant will equally share the cost of a program that has immediate benefit to the participant and long-range benefit to the non-participant.

We find the staff's recommended changes of Edison's proposed TOU-D schedule to be reasonable. Rate neutrality between time-of-use and standard rates is an appropriate consideration in developing the rate design for TOU rates. The rate design proposed by the staff not only achieves such rate neutrality, but ensures, when coupled with staff's recommended meter charge, the equitable treatment of all residential ratepayers.

4. Submeter Discounts

Edison's residential service includes two domestic rate schedules (DMS-1 and DMS-2) which provide for payment by Edison to a property owner who, through a master meter, provides submetered service to his tenants. The owner is compensated through a discount on his monthly billing rates for each submetered customer. The discount essentially reflects the costs that Edison would have incurred in providing comparable services directly to the submetered customer.

The DMS-1 schedule, which applies to all master meter customers other than mobile home parks, is not in dispute in this proceeding. Edison and the staff both propose to maintain the existing discount, but change it to a "daily" rate. The Edison proposal, however, rounds the daily rate to 7¢ per day resulting in a 6.5% increase. Staff believes that the daily discount should be rounded to 6¢ a day (an 8.5% decrease) to recognize the fact that the Public Utilities Code has been amended to require the utility to furnish public safety customer services to each submetered tenant. The code also requires the Commission to "deduct the average cost of providing these public safety customer services when approving rate differentials." (PU Code § 739.5(c).) Consistent with our discussion of the DMS-2 discount, we find reasonable and will adopt staff's calculation of the daily discount for the DMS-1 schedule.

Unlike the DMS-1 schedule, the DMS-2 schedule, in particular the allowable discount, was the source of considerable disagreement during this proceeding. Basically, three different positions were taken by Edison, the staff, and Western Mobilehome Association (WMA)[1] with respect to the required discount. The recommendations of these parties have the same basic starting point--Edison's cost of service study for the DMS-2 schedule. The dispute, however, centers on the extent to which the results of that study could be adjusted consistent with the applicable law.

The applicable statute is PU Code § 739.5 which provides in pertinent part as follows:

> "The Commission shall require the corporation furnishing service to the master-meter customer to establish uniform rates for master-meter service which will provide a sufficient differential to cover the reasonable average costs to master-meter customers of providing submeter service, except that these costs shall not exceed the average cost the corporation [utility, in this case Edison] would have incurred in providing comparable services directly to the users of the service." (PU Code § 739.5(a).)

When § 739.5 was enacted, this Commission opened an investigation to study the implementation of the differential rate (C.10273). In that proceeding cost data from utility and mobile home park owners was received and analyzed. The methods for compiling and evaluating submetering costs and setting the level of the differential were

---

[1] The WMA is a statewide association of mobile home park owners, many of whom are master meter customers served by Edison under its DMS-2 schedule.

established in that case. The Commission accepted the utilities' submission as to comparable costs in the form of studies of what costs utilities incurred in directly serving mobile home park residents in the non-master-metered circumstance. (D.89907 (1979).)

Since Edison first submitted its cost study in C.10273, the study has been updated in succeeding general rate cases. In Edison's last general rate case, the results of the study led to the adoption of the present $5.95 monthly discount per submeter.

In this proceeding, Edison again provided an updated study of costs it would incur in providing comparable service directly to the submetered tenants. The study is basically in the same format as the original study performed in C.10273 and includes both established and new mobile home parks. Based on this study, Edison originally proposed that the DMS-2 monthly discount be increased to $8.90 per customer.

The staff determined that this increase of nearly 50% in two years warranted a careful examination of Edison's study. In the process of this examination, the staff determined that the costs to be used in measuring Edison's otherwise existing obligation should be those costs which Edison does not incur, but would incur were Edison to provide the service directly. Using this approach, the staff recommended that the following costs be excluded from Edison's proposed discount:

- Customer Service and Information expenses. The staff testified that these residential conservation programs and associated informational services are provided to submetered customers the same as to any other Edison residential customers. Thus, rather than being a cost Edison would have incurred should it serve these customers directly, it is a cost that Edison does incur for such customers.

- o Franchise fees. The staff asserts that these fees are completely dependent on the revenues which Edison derives from its sales whether those sales are to mobile home customers or other residential customers. As such, these are costs that Edison does in fact incur.
- o Master meter costs. Staff states that Edison's original proposal did not reflect a credit against the discount representing the cost of the master meter. This cost is one which Edison would not incur were it to undertake the service to submetered customers directly.
- o Equity component of all plant costs. Staff believes that this component should not be part of the discount since equity represents the profit of the utility. Since it is profit and not a cost, it should therefore not be considered in the discount.

These revisions of Edison's study resulted in staff proposing a flat cost discount of $5.17 per month.

During the course of the hearings, Edison's witness concurred with staff's adjustments of Edison's study with the exception of staff's exclusion of profit. In Exhibit 127, Edison updated its DMS-2 study to reflect these changes and reduced its proposed monthly discount to $7.26.

WMA agreed with only one of staff's reductions to the monthly discount--the cost of serving the master meter. With this exception, WMA is otherwise adamantly opposed to staff's recommendations. WMA asserts that staff's proposals deviate from the requirements of PU Code § 739.5 and the methodology adopted by the Commission in C.10273 after two years of study.

Specifically, WMA states that staff's approach is inappropriately based on Edison's avoided costs as opposed to the utility's average costs, the required measure of Edison's obligation under § 739.5. Average costs, according to WMA, are the sum of all

costs including avoided costs, historical costs, and fixed costs, divided by the number of units served. WMA argues that the escalation of the utility's average costs is an insufficient reason to deviate from either the applicable statutory standard or the methodology adopted to implement the statute.

WMA asserts that, based on its update of a prior study, the discount should be a minimum of $7.40 per month per space. Because this study did not take into account new mobile home park spaces added after 1979, however, WMA believes that it is more appropriate to provide a monthly discount of $8.02 per customer. This figure represents Edison's originally proposed discount less the cost of providing service to the master meter.

WMA is correct in stating that escalating costs alone would not allow the Commission to alter an adopted methodology without notice and an opportunity to be heard by all parties. The specter of "uncontrolled costs" would, if anything, suggest that the Commission consider an alternative. One such alternative has been suggested by the staff in its reply brief. Specifically, staff states that the DMS-2 schedule could be closed to new mobile home parks and the utilities required to directly meter all new mobile home park tenants.

We believe, however, that such a step is currently unwarranted and that the present methodology will yield a discount which will properly compensate mobile home park customers and be reasonable for Edison's ratepayers. We disagree with WMA that the methodology which the Commission adopted in C.10273 is somehow completely static. The definition of average costs of the utility obviously can change especially in the event of Commission action. An example of this situation has been noted by the staff. In 1980, after we had adopted the utilities' cost studies in C.10273, we ordered the major electric utilities to provide conservation services directly to submetered tenants. To take into account such a change

in the cost equation (i.e., removing Customer Services and Information expenses from the discount) does not violate the adopted methodology, but rather applies it in a reasonable manner.

Further, while WMA recognizes in part that the "average costs" in question are those of the utility, WMA also argues that "[m]aster meter customers are entitled to receive a differential retaining their average costs." (WMA Reply Brief, at p. 3; emphasis added.) This particular argument appears to be part of the basis for WMA contesting the exclusion of Customer Services and Information costs and franchise fees from the discount.

The removal of profit as a reimbursable cost, however, does not appear appropriate. As WMA points out and staff conceded in its testimony, Edison's cost studies for submetered customers has, since its inception in C.10273, included an amount for rate of return. We have been provided with an insufficient basis to alter that approach in this proceeding.

For these reasons, we have concluded that Edison's revised DMS-2 study contained in Exhibit 127 is the most appropriate basis for determining the monthly discount to which master meter customers are entitled for each submeter. The $7.26 monthly cost per unit contained in that exhibit, however, includes plant carrying charges based upon a 13.51% rate of return. We will therefore adopt as reasonable a flat cost discount per month per customer for the DMS-2 schedule based upon Exhibit 127 adjusted for the rate of return adopted in this decision today.

B. Daily Rates

Edison proposes that its tariffs for non-demand rate schedules be converted from a monthly rate charge to a daily rate charge. Our previous discussion of residential rates incorporates this recommendation into the adopted rate design for Edison's domestic schedules.

As that discussion indicates, the staff had no objections to the institution of daily rates for residential customers. Staff agreed with Edison that the use of daily rates for domestic service would enhance the understanding and application of baseline.

The staff, however, does not see any benefit of daily rates to customers who are on flat or unmetered schedules, such as streetlighting. The staff believes that varying bills for customers who budget on a monthly basis and are on flat schedules may present problems. With respect to prorationing when a new rate schedule goes into effect, the staff sees no advantage of daily rates to streetlighting customers since the ratio of old and new rates in their bill will be the same with or without daily rates. Staff also sees no need to apply daily rates to agricultural or small light and power customers.

Cal-SLA joins the staff in asking for the rejection of Edison's proposed daily rates for streetlighting customers. Cal-SLA states that there is no practical justification for daily rates versus the current monthly rates paid by streetlight customers. In Cal-SLA's view, daily rates should not be implemented under any circumstances.

Edison is willing to defer the implementation of daily rates for streetlighting customers. Specifically, such implementation would be deferred until base rates for this customer group are revised in keeping with a complete cost of service study which could be submitted in the course of Edison's ECAC application for June 1985. Edison supports this alternative, however, only if

the Commission adopts staff's proposal to base streetlighting rates on imbedded costs.

As discussed in the following sections, we find reasonable the implementation of daily rates for all non-demand, non-TOU commercial and industrial customer groups except streetlighting. We find insufficient justification in this record for switching streetlighting customers to daily rates, either on a deferred or immediate basis. The administrative burdens imposed by retaining monthly rates for streetlighting customers appear de minimus since Edison will merely be required to maintain streetlighting rates on the same basis as currently exists.

C. Commercial and Industrial Rate Design

The schedules available to Edison's commercial and industrial customers include those which are based on the customers' time-of-use (TOU) and those which are not. The non-TOU schedules include GS-1 and GS-2 for lighting-small and medium power (LSMP) customers and PA-1 and PA-2 for agricultural and pumping customers. TOU rate schedules are available to both of these customer groups and mandatory for large light and power (LLP) customers.

1. Non-Time-of-Use Rates

a. GS-1 and GS-2 Schedules

As stated above, the principal non-TOU rate schedules for the LSMP group are GS-1 and GS-2. Edison proposes to make only a few limited modifications to these schedules. Specifically, Edison believes that the energy rate for the GS-1 schedule should be raised (on a cents per kWh basis) in order to maintain the rate relationship between the GS-1, D (the principal domestic schedule), GS-2, and PA-1 (non-demand agricultural schedule) schedules. Similarly, for Schedule GS-2, Edison seeks to increase the energy and minimum charges to maintain the rate relationship between GS-2, GS-1, and PA-2 (a demand agricultural schedule) schedules.

Staff recommends that no increase be made to the minimum charge on Schedule GS-2 and that any rate increase be placed solely on the energy charges for the GS-1 and GS-2 schedules on an equal cents per kWh basis. Staff believes that Edison's proposals again reflect an overriding concern with customer migration. Staff asserts that the current minimum bill for GS-2 customers should be a sufficient deterrent to preclude GS-1 customers from switching to that schedule. In staff's view, only a very high usage domestic customer might benefit by migrating from the domestic schedule to GS-1. Under these circumstances, however, the staff believes that the problem can be adequately addressed by tariff language which would restrict the customer's ability to change schedules.

Edison also proposes the implementation of daily rates for GS-1 customers. Staff states that it is not so much opposed to this change as unaware of any resulting benefit.

We concur with the staff that little justification has been presented for altering the GS-1 and GS-2 schedules solely on the basis of deterring customer migration. The problem, if it exists at all, appears to be minor and can be adequately remedied, if necessary, by restrictive tariff language. We therefore adopt the staff's position regarding rate setting for GS-1 and GS-2 schedules in the event of an increase to those rates. A rate decrease should be handled in the same manner, with the decrease being reflected in the energy charge on an equal cents per kWh basis.

As we stated in the previous section, we have been presented with insufficient grounds for implementing daily rates only for streetlighting customers. Staff's response to Edison's suggested implementation of daily rates for the GS-1 schedule does not warrant the retention of monthly rate charges for that schedule. We therefore adopt Edison's recommendation to base the GS-1 schedule on daily rates.

b. PA-1 and PA-2 Schedules

Edison recommends increasing the energy charge on Schedule PA-1 to maintain its relation with PA-2 and GS-1. Staff agrees with Edison that the connected load charge in the PA-1 schedule ($1.00 per horsepower) and the demand charge in PA-2 ($3.75 per kW) should be retained and any resulting increase be placed on the energy charges. We find reasonable and will adopt this position in the event of either a rate increase or rate decrease.

The California Farm Bureau Federation (Farm Bureau) proposed in its opening brief in this proceeding that "for California agriculture to remain economically sound and competitive, the Commission must, as it did in D.82-05-042, set irrigation rates at the residential baseline rate." (Farm Bureau Opening Brief, at p. 6.) The Farm Bureau argues that energy is one of the highest costs related to agricultural production. The farmer, however, is not always able to pass this cost along to the customer since he can sell his commodity only at the going market price. To ensure that availability of agricultural commodities remains at its current level, the Farm Bureau asserts that the Commission must make "a policy decision providing lower energy rates to agriculture." (Id., at p. 7.)

Both Edison and the staff in their reply briefs opposed the Farm Bureau's proposal. In their briefs, these parties point out the distinctions between this proceeding and D.82-05-042, cited by the Farm Bureau in support of its recommendation. As these parties state, in D.82-05-042 the Commission did set rates for Pacific Power and Light Company's (PP&L) irrigation customers at the residential lifeline (baseline) rate. The Commission took this action "in this particular case" in recognition of the competition between Oregon and California agriculture for which allowances should be made. The Commission's action had the effect of moderating a substantial proposed increase in irrigation rates. In a subsequent

decision (D.84-07-150) involving PP&L, the Commission adopted percentage increases for irrigation service and did not continue to tie irrigation rate levels to lifeline (baseline) rate levels.

On this basis, Edison believes that D.82-05-042 does not support the Farm Bureau's recommendation and that the Farm Bureau proposal should be rejected. Staff concurs that D.82-05-042 was issued to address a particular problem developed on the record in PP&L's application. Staff asserts that in this proceeding neither the Farm Bureau nor any other party presented evidence addressing the need to set irrigation rates at baseline rate levels.

In reviewing the record, we, like the staff and Edison, can find no evidence to support the setting of irrigation rates at the same levels as baseline rates. While we are concerned with the farmer's plight, it was necessary for the Farm Bureau to present facts during the hearings in this proceeding to justify such a recommendation. While such facts existed in the case of PP&L's agricultural customers, the Farm Bureau has not demonstrated that a similar situtation exists for Edison's agricultural customers. We must therefore reject the Farm Bureau's proposal.

2. Time-Of-Use Rates

Time-of-use (TOU) rates are currently available to Edison's large light and power (LLP), lighting-small and medium power (LSMP), and agricultural customer classes. These schedules include the following:

- o TOU-8. Schedule TOU-8 is a mandatory time-of-use rate schedule for all LLP customers with loads exceeding 500 kW. At the present time, TOU-8 has time-differentiated demand and energy charges and a $560 monthly customer charge. These rates are not seasonally differentiated.
- o TOU-GS. This schedule is an optional time-of-use schedule available to the LSMP customer class. The schedule has a demand charge related to peak monthly load, a minimum bill, and time-differentiated energy rates.
- o TOU-PA-1, TOU-ALMP-1, TOU-ALMP-2. These time-of-use schedules are available to Edison's agricultural customers. The first schedule, TOU-PA-1, is the current permanent agricultural time-of-use rate schedule. In 1981, an experimental time-of-use program was begun with schedules TOU-ALMP-1 (demand and energy charges) and TOU-ALMP-2 (energy charge only). This program has proven highly successul attracting more customers than TOU-PA-1.

At the present time, only 1.24% of Edison's commercial and industrial customers are on time-of-use rates. These customers, however, represent 51.54% of Edison's commercial and industrial sales. Further, while only 11.02% of Edison's agricultural customers are on time-of-use schedules, these customers account for 33.78% of all sales to the agricultural class.

These figures reflect that this Commission's conclusions with respect to the appropriate time-of-use rates for these customer classes will impact a significant percentage of Edison's sales. It is, therefore, not surprising that the issues

relating to time-of-use rates were vigorously debated by many parties. These issues include the need for changes to the rate components and rate design of all of the time-of-use schedules and the propriety of exemptions from mandatory time-of-use rates. Challenges to both the Commission's current policy with respect to time-of-use rates as well as the consistent application of that policy have been raised.

Because this Commission's overall policy is generally at issue in this case, we will first summarize the parties' positions on the various time-of-use issues. This summary will be followed by our discussion and resolution of those issues.

a. Time-of-Use Issues

(1) Edison and Staff Proposed Rate Design

In this proceeding, Edison has proposed to retain the current level of demand and customer charges for TOU-8 customers. Using Edison's approach demand charges would remain time-differentiated and would be set on a monthly basis at $5.05 during on-peak periods and $0.65 during mid-peak periods. Any increase in rates, however, would be reflected in an energy rate. All rate relationships would be established on a cents per-kilowatt-hour basis which would be maintained between rate cases. Edison does not recommend changing its TOU-8 schedule to provide for seasonally differentiated rates.

In contrast, the staff has recommended several significant modifications of Edison's TOU-8 rate schedule. It is staff's opinion that its proposal conforms with Commission policy and will yield more appropriate price signals than the current TOU-8 rate design. Staff has described the Commission's current policy as follows:

> "In recent years the Commission has evolved clear policies with respect to TOU rates. First, as reflected in the recent PG&E and SDG&E decisions, as well as the test year 1983 Edison decision,

the Commission has indicated a policy of deemphasizing rate components that do not vary with usage. It is the Commission's view that rates that are based on components that do not vary with time do not promote conservation. (D.83-12-068 at 387; D.83-12-065 at 162; D.82-12-055 at 237, 240.) Thus all increases to TOU rates (and other schedules having demand and customer charges) have been to the energy charges of the rates.

"In addition, in the recent PG&E general rate case the Commission took those demand charges that existed for TOU schedules and made them flat with respect to time. (D.83-12-068.)

"The same demand charge exists during all billing periods and the periodic bill would be based on the highest demand during that billing period irrespective of the time of day at which it occurred.

"The Commission has also indicated that TOU rates should be seasonally differentiated to reflect differences in marginal costs (principally capacity costs) that occur between summer and winter periods. (D.83-12-068 at 388.)

"Finally, in the last Edison general rate case the Commission indicated that the optional TOU schedules--specifically TOU-GS--should have their availability expanded. (D.82-12-055 at 240.)" (Staff Opening Brief, at pp. 111-112.)

Guided by this policy, the staff recommends that the demand charge for Edison's TOU-8 schedule be made flat with respect to time. This non-time-differentiated demand charge would be set at $4.00/kW per month. Staff states that the overall revenue collected from the demand charge would not change and would no longer be determined by a customer's peak- and mid-peak usage. Instead, the demand charge billed would be based on the maximum demand during the billing period.

Staff believes that the effect of its adjustment of the demand charge is to move that charge closer to the marginal cost of distribution which does not vary with time. Staff,

however, does not recommend using the exact marginal distribution cost figure because it would result in significant bill changes.

With respect to other aspects of TOU-8 rates staff proposes to replace the TOU-8 customer charge with a minimum charge. Further, staff recommends that the full marginal cost of energy and capacity be reflected in the energy rate by applying a proportional combination of the equal percent of marginal cost (EPMC) and system average percentage change (SAPC) methodologies to the individual rates. Staff also urges that Edison's TOU-8 schedules be seasonally differentiated. Between rate cases, staff recommends that rate changes be accomplished by using the same method as it recommended for revenue allocation among the customer classes--the system average percentage change applied to the individual energy rates with adjustments to maintain consistent ECAC rates when sales by time period change.

Edison asks the Commission to reject staff's proposed seasonally differentiated TOU rates and minimum charge. Edison asserts that the changes will adversely impact approximately 320 TOU-8 customers, increasing their annual bills between 10% and 95%. In comparison, Edison's proposed TOU-rate design would adversely impact approximately 45 customers by increasing bills between 10% and 55%. During oral argument in this proceeding, Edison acknowledged that its subsequently proposed rate decrease would reduce the percentage increase in bills estimated for staff's proposal by 10% to 15%.

With respect to TOU-8 billing reductions, Edison claims that the staff's proposed rate design would yield reduced TOU-8 billings to approximately 90 customers in the range of 0% to 30%. Edison's proposal would yield reduced billings to 15 customers in the range of 0% to 15%.

Edison believes that these figures reflect the greater volatility of staff's proposed rate design for TOU-8

rates. Further, Edison asserts that staff's rate design will increase the incidence of customer migration or transfers beteen non-time-of-use rate schedules and TOU-8. For these reasons, Edison urges the rejection of staff's proposed rate design for TOU-8.

CMA believes that the insupportability of either staff's position or the Commission policy in this case suggests that the time is ripe for a review of all time-of-use rates. Specifically, CMA proposes that the Commission institute a generic proceeding on TOU rates for the purpose of developing a comprehensive policy governing those rates.

(2) TOU-8 Demand Charge

The Independent Energy Producers (IEP) believe that staff's proposal toward distribution-based demand charges over time is "a step in the right direction, but an overly cautious one." (IEP Opening Brief, at p. 32.) IEP asserts that the time is ripe for an immediate reduction in demand charges to the distribution-based level of $1.50/kW per month.

IEP argues that Edison's current TOU-8 demand charges create an unreasonable hardship for cogenerators serving their own loads. IEP contends that such a result is particularly inappropriate since a rate structure including high demand charges is not cost-justified. IEP notes that demand costs are not incurred in any single hour even though the demand charge collects for them in that way. IEP describes this situation as "contribution to system stress." Further, a customer may reach its maximum demand in the lowest cost hour of a particular time period, but will be charged the same demand charge as a customer available in 100% of the peak hours. IEP refers to this circumstance as "coincidence with system stress."

Should its proposed demand charge not be adopted by the Commission, IEP asks in the alternative that the

Commission modify the TOU-8 rate schedule for cogenerators (TOU-8-CG) "who are overpaying based on contributions to system stress and coincidence." (IEP Opening Brief, at p. 33.) IEP proposes that the Commission establish, either in this proceeding or for consideration in Edison's next general rate case, a TOU-8-CG rate which is based on a distribution-only demand charge.

Edison, CMA, and GM/Union Carbide all take issue with staff's proposed TOU-8 rate design. Of greatest concern to these parties is staff's recommended non-time-differentiated demand charge. These parties argue that the staff's conclusions are based on no studies or analyses, but only the precedence set by this Commission's previous decisions, in particular the decision in PG&E's last general rate case. These parties believe that even in that case the Commission's policy was not founded on any study nor was it based on any review of the impact of reducing or eliminating demand charges.

In contrast, these parties believe that substantial evidence has been presented in this proceeding which demonstrates that "the Commission's present energy charge emphasis is misguided and ineffective in relation to its stated policy goals (i.e., appropriate price signals)." (GM/Union Carbide Opening Brief, at p. 10.) This evidence consists of (1) an econometric study performed by Edison showing that the "total elimination" of demand charges on customers above 5,000 kW would increase system demand by 16 megawatts (MW), and (2) a real time analysis of the impact on steel producers of an all-energy non-time differentiated rate structure. In the latter case, Edison asserts that its study demonstrates that the elimination of demand charges in the legislatively mandated steel producers rate schedule has led to higher on-peak usage than when those customers were on the TOU-8 rate schedule. Based on this evidence, Edison, CMA, and GM/Union

rates. Further, Edison asserts that staff's rate design will increase the incidence of customer migration or transfers beteen non-time-of-use rate schedules and TOU-8. For these reasons, Edison urges the rejection of staff's proposed rate design for TOU-8.

CMA believes that the insupportability of either staff's position or the Commission policy in this case suggests that the time is ripe for a review of all time-of-use rates. Specifically, CMA proposes that the Commission institute a generic proceeding on TOU rates for the purpose of developing a comprehensive policy governing those rates.

(2) TOU-8 Demand Charge

The Independent Energy Producers (IEP) believe that staff's proposal toward ditribution-based demand charges over time is "a step in the right direction, but an overly cautious one." (IEP Opening Brief, at p. 32.) IEP asserts that the time is ripe for an immediate reduction in demand charges to the distribution-based level of $1.50/kW per month.

IEP argues that Edison's current TOU-8 demand charges create an unreasonable hardship for cogenerators serving their own loads. IEP contends that such a result is particularly inappropriate since a rate structure including high demand charges is not cost-justified. IEP notes that demand costs are not incurred in any single hour even though the demand charge collects for them in that way. IEP describes this situation as "contribution to system stress." Further, a customer may reach its maximum demand in the lowest cost hour of a particular time period, but will be charged the same demand charge as a customer available in 100% of the peak hours. IEP refers to this circumstance as "coincidence with system stress."

Should its proposed demand charge not be adopted by the Commission, IEP asks in the alternative that the

Carbide urge the adoption of Edison's TOU-8 demand charge proposal and the rejection of both staff's and IEP's proposals.

IEP and staff, however, question the relevancy of this evidence to their proposals, in particular the "steel producers' example." Both parties note that this rate does not in fact include any demand charge nor does it provide any time-differentiation of energy charges. Rather, it includes a flat rate used 24 hours a day, 365 days per year. With such a rate, staff observes that "it is no wonder that on-peak usage may have increased." (Staff Opening Brief, at p. 115.)

In staff's view, the TOU-8 rate design which it proposes is in no way comparable to the steel producers' rate. Further, with significant time and seasonal differentiation, staff believes that its TOU-8 rate design provides a major incentive to have as little on-peak usage as possible due to the much higher on-peak rates. Staff states that demand charges in contrast provide no incentive to reduce demand once a maximum is reached, an incentive which the staff believes its approach provides.

(3) TOU-8 Interruptible Rates and Voltage Discounts

Other components of TOU-8 rates at issue in this proceeding are the interruptible rates and voltage discounts. Interruptible rates are discounts applied to the bills of TOU-8 customers for their agreement to allow their usage to be interrupted by Edison at a time of system need such as system load, forced outages, or some other problem. Edison currently has four interruptible schedules designated I-1, I-2, I-3, and I-4. The four schedules vary with regard to the length of notice prior to interruption, crisis basis for interruption, limitations on the number of interruptions, and length of customer commitment to the schedule. There are customers on interruptible schedules I-1 and I-2, but not on I-3 or I-4.

Voltage discounts have been established to reflect the fact that large light and power customers take their energy at higher voltages than other customers. This circumstance results in a reduction in line losses and the amount of transformation-related equipment the utility must provide to serve them.

While Edison has proposed no revisions of either its current interruptible rates or voltage discounts, the staff believes that both of these TOU-8 rate features should be restructured. Staff is joined in urging changes to the voltage discounts by the California Large Energy Consumers Association (CLECA), and GM/Union Carbide.

With respect to interruptible rates, staff has proposed a complete restructuring of these schedules "to offer a greater range of options and to relate the discounts paid to both the service provided to the utility and the cost incurred by the customer." (Staff Opening Brief, at p. 116.) Staff believes that currently the discounts are made without regard to whether interruptions actually occur. The discounts may also no longer be related to marginal costs.

The options suggested by the staff include alternate sign-up periods of 1 to 5 years, notices of interruption ranging from zero (automatic interruption) to two hours, and a payment structure based in part on regular monthly payments and in part on each interruption. Staff believes that this distinction in payments is justified in recognition of both costs incurred even without an interruption (i.e., equipment modification, backup generation, stockpiling of certain items) and costs incurred with an interruption. Staff has tied payments for automatic and noticed interruptions to the utility marginal costs of capacity and generation respectively. Staff also believes that some limitation on the number of interruptions and their length in a given year (e.g., one year) might also be appropriate.

Finally, staff recommends a "guaranteed curtailable load" option comparable to a similar option available in PG&E's service territory. This option would require a customer to ensure that during a curtailment period a certain amount of load would exist which the utility could reduce. A penalty would be imposed if the guaranteed curtailable load did not exist. CLECA joins the staff in supporting a curtailment option which provides no notice to the customer. CLECA asserts that this option would be beneficial to Edison since it would contitute spinning reserve capacity for the Edison system. CLECA states, however, that in exchange for this benefit, customers with large loads must be adequately compensated. CLECA proposes a combination of specific incentive credits (cents/kWh) and performance credits ($/kW) to compensate such customers. The incentive credit would allow the customer to estimate the net compensation that would accrue from participating in the zero notice option and to compare those credits to the cost of installing standby equipment. The performance credit is designed to compensate for the other costs incurred by the customer during periods of interruption. The actual numbers proposed by CLECA for these credits depends on whether the Commission adopts CLECA's other proposal to segregate TOU-8 customers into three subgroups (see infra) or not. CLECA also believes, like the staff, that the periods of interruption should be limited. CLECA states that 180 hours per year is a reasonable limitation.

CMA and Edison again take issue with these proposed changes to Edison's present interruptible schedules. Edison asserts that no evidence has been presented justifying the inclusion, as staff has done, of marginal transmission and distribution costs in the marginal capacity cost credit calculation for interruptible customers. Edison believes that interruptible customers are analogous to qualifying facilities which the

Commission has found do not avoid utility transmission and distribution costs. Additionally, Edison asserts that no evidence has been presented to demonstrate that there would be a load reduction commensurate with the capacity credit. Further, Edison asserts that the staff has provided no cost-effectiveness analysis of its proposed interruptible rate discounts. Edison states that it performed such an analysis for its present interruptible rates which shows that such rates are cost-effective.

CMA argues that staff's proposal does not provide the necessary incentive to interest potential customers in Edison's interruptible schedules. Specifically, CMA states that basing the level of discounts on the number of interruptions creates an undesirable degree of unpredictability regarding the costs and benefits available to the customer. In CMA's views the customer must be able to calculate these costs with some certainty in order for the customer to decide whether to accept an interruptible contract. Staff's failure to take into account the significance of capital costs to potential interruptible customers is reflected, in CMA's view, by the very manner in which staff has proposed to restructure interruptible rates. In this regard, CMA notes that staff has focused its entire attention on restructuring Schedules I-3 and I-4, which currently have no customers, and has suggested the closing of Schedules I-1 and I-2, which have customers and pay a fixed discount to customers who sign up on those schedules whether or not any interruptions occur.

CMA also believes that staff's "guaranteed curtailable load" rate option has an anti-conservation effect. The basis for CMA's opinion is that the option creates an incentive to increase and sustain as large a load as possible when facing a likely curtailment period in order to have load to curtail and avoid the possibility of a penalty. In CMA's view, a rate creating this

type of incentive encourages inefficient consumption decisions and contradicts Commission rate design policy.

Both the staff and CLECA also join in urging the Commission to modify Edison's current voltage discounts. At the current time, Edison's TOU-8 schedule permits voltage discount of 3%, 4%, and 5%, depending on whether a customer takes power from Edison at low, medium, or high voltage levels respectively. CLECA believes that these voltage discounts are too low and do not reflect the actual marginal costs to serve the various customers within the TOU-8 schedule. In CLECA's opinion, because all TOU-8 customers are aggregated in one schedule, the result is that some customers within that schedule are subsidizing other TOU-8 customers. According to CLECA's testimony, it costs Edison approximately 13% less to serve the high voltage cutomers and 3% less to serve the medium voltage customer within that group.

In response to these circumstances, CLECA states that the Commission should adopt rates for TOU-8 customers that reflect the differences in marginal costs to serve the subtransmission, primary and secondary customers within the class. Specifically, CLECA recommends that TOU-8 should be separated into three sub-groups (subtransmission, primary, and secondary) with separate rates developed for each of those groups.

Staff believes that modifications to the TOU-8 voltage discount should be accomplished in two stages--the first in this rate case and the second in Edison's next general rate case. For this rate case, staff recommends the recalculation of the voltage discount to reflect the differences in marginal costs to serve customers in the three different voltage groups. For the next rate case, the staff recommends that the need for a voltage discount as a separate item be eliminated by initially incorporting voltage differences among large customers into the basic allocation

process. As similarly proposed by CLECA, this goal would be accomplished by separating TOU-8 customers into three groups based on the voltage levels of below 2 kV, 2 kV to 50 kV, and greater than 50 kV, and developing separate marginal costs for each subgroup. The discount would then be incorporated into the allocation and rate design.

GM/Union Carbide concurs with the need for changes to the current TOU-8 voltage discounts. GM/Union Carbide, however, finds that staff's alternatives "are very conservatively formulated" and endorses CLECA's approach of separating the large power customers into three subgroups with separately established marginal cost based rates. GM/Union Carbide nevertheless conceded that staff's recommendation is a "substantial step in the direction of achieving cost conformity for Edison's large power rates." (GM/Union Carbide Opening Brief, at p. 13.)

During the hearings, notably in Edison's rebuttal Exhibit 133, Edison indicated that it did not oppose the level of the staff's proposed voltage discount. The opening briefs of parties addressing this issue reflect this understanding of Edison's position. In its brief, however, Edison instead asserts that staff's and CLECA's voltage discount proposals are technically flawed by including certain inappropriate marginal costs. With respect to treating TOU-8 customers as three separate subgroups, Edison contends that this change requires revising the applicable marginal costs by making additional assumptions associated with each voltage level. Edison claims that when the revised costs by voltage level are applied to kilowatt-hour sales by voltage level, the revenue relationships between customers would also change. Due to these circumstances, Edison believes that it would be preferable to defer consideration of the voltage discount proposal until such time as Edison is able to complete the revision of marginal costs resulting from dividing the LLP group into three separate subgroups.

(4) Exemptions from TOU-8 Rates

The Association of California Water Agencies (ACWA) requests that its members be exempted from mandatory application of TOU-8 and that water pumpers currently on TOU-8 be permitted to elect TOU-ALMP-1, TOU-ALMP-2 or PA-2 as tariff options. In support of its position, ACWA attacks the very purpose of TOU rates by claiming that mandatory TOU rates are unnecessary to increase Edison system reliability and have not proven effective in shifting customer use by time of day. According to ACWA, it is more costly to Edison ratepayers to continue mandatory TOU rates to improve load factors on existing oil/gas-fired plants than to construct new solid fueled (coal) powerplants.

With respect to its members, ACWA asserts that mandatory TOU rates are unduly burdensome for those of its members who it claims are 100% load factor customers with a constant demand at all hours every day. ACWA believes that its members are penalized by high peak rates, their inability to afford the capital improvements necessary for them to shift load, and the difficulty of deciding to make changes in the face of potential changes in rate design.

Both staff and Edison believe that the Commission has clearly established a policy against customers being granted exemptions from mandatory time-of-use rates. Further, staff questions the evidence presented by ACWA in support of its position. In particular, staff points out discrepancies in ACWA's testimony as to what was meant by 100% load factor, asserting that some members only had this characteristic in two months (July and August) of the year. Additionally, staff believes that ACWA's coal plant example was inapposite since the only utilities to use coal plants to follow load were those utilities which only have coal plants. Staff also states that the rate which should be provided ACWA in lieu of time-of-use rates (a flat rate based on the same class as the TOU rate) could result in higher costs for customers

with a 100% load factor. Finally, in the staff's judgment, to make reclaimed water (which ACWA also claimed was adversely impacted by TOU rates) cost-competitive with imported water would require a drastic reduction in Edison's rates for ACWA's members.

(5) TOU-PA (Agricultural) and TOU-GS (LSMP) Rate Schedules and Rate Design

Staff recommends that one permanent agricultural TOU schedule be established, designated TOU-PA, and all other agricultural TOU schedules be closed. The vehicle for this permanent option schedule would be TOU-ALMP-2. According to the staff, TOU-ALMP-2 has rates which closely reflect marginal cost by time period. The schedule also has on-peak hours which are the same as TOU-8 and TOU-GS and has no demand charge, which would reflect the Commission's emphasis on charges varying with usage. It is the position of the staff that the new schedule TOU-PA, if adopted, be open to all who qualify subject to meter availability.

For both TOU-PA and TOU-GS, staff recommends that the rate design for these schedules be based on the principle of rate neutrality. The staff believes that this approach is necessary to ensure that a customer not receive a lower bill on this schedule than a non-time-of-use schedule unless their on-peak usage is less than the class average on-peak usage.

The California Farm Bureau Federation (Farm Bureau) recommends that both of the experimental agricultural time-of-use rate schedules (TOU-ALMP-1 and TOU-ALMP-2) become permanent tariff options available on a voluntary basis to all members of the agricultural class and that TOU-PA-1 be closed. The Farm Bureau believes that staff's position does not provide agriculture with the many energy options which it requires because of the diversity in the commodities produced and in the climates of the areas of production.

The Farm Bureau also seeks the application of staff's proposed time-of-use periods (see discussion infra) to the agricultural time-of-use rate schedules. The Farm Bureau further proposes that the on-peak periods be the same for the agricultural schedules, with all other hours being off-peak hours.

Edison takes issue with the last of the Farm Bureau's recommendations. Edison notes that staff's proposed costing periods are based on the three time-of-use periods used for TOU-8 rates (on-, mid-, and off-peak). In the development of a two-period TOU-rate, Edison believes that consideration must be given to how the mid-peak period is to be treated. Edison states that instead of arbitrarily considering all of this period to be either on- or off-peak periods, Commission should follow its prior approach for two-period TOU rates of placing part of the mid-peak period in on-peak and part should be considered off-peak. Edison asserts that the Farm Bureau has presented no reason for changing from this policy.

b. Discussion

The objective of time-of-use rates is to encourage the shifting of load or electrical usage from peak periods of high demand to periods of lesser demand. This load-shifting is designed to promote the optimum use and efficiency of existing electric plants. Time-of-use rates also provide more accurate price signals to the consumer when they are based on the utility's marginal costs.

The staff has been criticized in this proceeding for many of its suggested changes to Edison's current time-of-use rates on the basis both of doing too little for and of doing too

much to certain customers. Yet no party to this proceeding, other than the staff, has consistently attempted to modify existing rate schedules in keeping with the dual goals of time-of-use rates--plant efficiency (the encouragement of load shifting) and economic efficiency (the development of marginal cost-based prices). The positions taken in this proceeding do not so much reflect an uncertainty about Commission policy with respect to time-of-use rates as a desire to avoid what are perceived to be some unappealing attributes of such rates.

We do not wish to minimize the fact that time-of-use rates appear to be subject to continual changes in each rate case. These changes, however, we believe are essential to ensure the viability of the purposes for time-of-use rates (plant efficiency) and utility rates in general (economic efficiency). We also understand the difficulty which certain customers may have in finding themselves precluded from time-of-use rate schedules or locked into only limited options. We, therefore, do not completely dismiss CMA's suggestion of a generic OII into the subject of time-of-use rates. Such a procedure could provide an opportunity for a more in-depth study of time-of-use rates than the time provided in a general rate case. With the three years intervening between this proceeding and Edison's next general rate case, such a study would easily be undertaken.

Until such a proceeding, however, we find that many of staff's suggested modifications of TOU rates are reasonable and in keeping with current Commission policy. For TOU-8 rates, we will adopt staff's non-time-differentiated flat demand charge with all rate increases or rate decreases reflected in the energy charge. We do not find this demand charge level "overcautious," as claimed by IEP, but reasonable in achieving the Commission goal of providing accurate price signals without significant bill changes. We find the evidence presented by Edison and CMA does not warrant

any deviation from our current policy of de-emphasizing the demand charge. We, like the staff and IEP, find this evidence, which was based on the total elimination or absence of a demand charge, as having little relevancy to the particular proposal made by the staff and adopted herein.

We similarly find reasonable and consistent with current Commission policy the staff's proposal for seasonally differentiated TOU rates and for a minimum charge. These changes to schedule TOU-8, therefore, will also be adopted.

In adopting the foregoing modifications of the TOU-8 rate schedule, we wish to state that it is not our desire to further Commission policy without any recognition of the potential negative impacts which that policy might have. For this reason, we conclude that it is reasonable to delay the implementation of the new TOU-8 rate design until the first seasonal transition in the test year.

With respect to other features of TOU-8 rates at issue in this proceeding, we find that the staff has quite appropriately suggested a restructuring of Edison's interruptible rates for TOU-8 customers. Our problems with those changes, however, have been mirrored in the comments of CMA. While we wish to promote a logical and reasonable program for interruptible customers, we also must provide sufficient incentives for those customers to agree to such changes in their electircal supply. We believe that this incentive is provided by adopting staff's revision of Schedules I-3 and I-4, while retaining Schedules I-1 and I-2. In this manner, the Commission will have the opportunity to determine whether or not the restructured Schedules I-3 and I-4, which in their current form have no customers do, in fact, provide sufficient incentives for large industrial customers to agree to interruptible status. All of these schedules, as well as staff' proposal for a "guaranteed curtailable load," will be adopted.

We do intend, however, to reexamine their impact and customer acceptance in Edison's next general rate case. We will also modify staff's recommended "zero notice" option to provide the credit incentives proposed by CLECA and the 180-hour limit per year on the periods of curtailment.

Similarly, we concur with CLECA and staff that a revision to Edison's voltage discounts for TOU-8 customers is required. We have found somewhat disturbing Edison's objections to both the voltage and interruptible rate discounts on the grounds of flaws in the staff's and CLECA's marginal cost calculations. Edison seems to have recognized the need for changes in both these areas and yet has taken no steps itself to determine what changes might be appropriate. Instead, Edison has simply satisfied itself with attacking the proposals which have in fact been made.

Nevertheless, although CLECA asserts that the Commission can separate TOU-8 customers into three subgroups now, we are not as confident that the record provides a sufficient basis for our segregating and adopting marginal cost-based rates for these subgroups in this proceeding. To accomplish the subgroupings proposed by staff and CLECA appears to require further analysis of the marginal costs associated with each of these groups. For this reason, we find staff's proposed two-step approach to the voltage discount issue to be a reasonable one. For this proceeding, we will adopt staff's recalculated voltage discounts for each of the three voltage categories of below 2 kV, 2 kV to 50 kV, and greater than 50 kV. For Edison's next general rate case, we direct Edison to file with its application a TOU-8 rate schedule divided into the three subgroups indicated, with rates based on marginal costs developed for each of those subgroups.

With respect to exemptions from TOU-8 rates, we reiterate our policy relied on by both staff and Edison that no

customer should be granted exemptions from mandatory TOU-8 rates. We find ACWA's evidence to alter this policy uncompelling. ACWA's testimony failed to demonstrate that our policies are not served by requiring ACWA's members to remain on TOU-8 rates or that its members are impacted to any greater degree than other customer on TOU-8 rates.

In dealing with ACWA's recommendations, we note that mandatory TOU rates are intended to achieve maximum economic efficiency while alleviating the inherent intra-class subsidies in voluntary TOU and non-time differentiated rates. As such, our adopted TOU-8 rates are designed to recover the same revenues as if they were non-time differentiated rates. This circumstance results in customers with a 100% load factor paying less than customers with a higher percentage of on-peak usage. Since our TOU rates reflect marginal costs which are time differentiated, this is the correct signal for customers to receive.

Both ACWA and staff recommend the same TOU-8 time periods which are designed to reflect the systems time differentiated increments of marginal cost. As described, infra, we have adopted these time periods.

Finally, we believe that the interruptible rates adopted in this decision may provide ACWA customers with a sufficient incentive to consider their use. We would encourage ACWA to analyze the cost versus benefits of these rates.

For the agricultural customers, we concur that the current TOU-PA-1 schedule should be closed. This schedule does not apparently offer the incentive to be on time-of-use rates as do the presently experimental schedules TOU-ALMP-1 and TOU-ALMP-2.

There seems to be little debate in this proceeding regarding the propriety of closing TOU-PA-1, the need to make the present experimental program for the agricultural class permanent,

and the need to open that program to all members of the agricultural class. The only issue is whether one or both of the experimental schedules should become permanent. In this case, we believe that it is reasonable to offer the agricultural class more than one time-of-use option. We continue, however, to seek to de-emphasize the demand charge. For this reason, TOU-ALMP-2 will become a permanent time-of-use schedule open to all members of the agricultural class on a voluntary basis. TOU-ALMP-1, however, will remain experimental until Edison's next general rate case. At that time, the Commission will again examine this schedule to determine whether or not to close the schedule, modify it, or continue it on a permanent basis.

Notwithstanding Edison's statement regarding the current policy on how to establish costing periods for two period time-of-use schedules, the tariffs presently in effect for agricultural customers show that these periods do correspond to the three usage periods on Schedule TOU-8. The off-peak period for Schedule TOU-PA-1 is the same as the off-peak period for Schedule TOU-8 while the on-peak period for this schedule covers both the on and mid-peak periods of Schedule TOU-8. For Schedules TOU-ALMP-1 and TOU-ALMP-2 the mid-peak period becomes part of the off-peak period with the on-peak period set the same as the TOU-8 on-peak period. We will continue this policy with the revised TOU-periods.

Finally, we adopt staff's rate design proposals for TOU-GS and TOU-8 designed to achieve rate neutrality. We also find reasonable, except to the extent modified in this decision, staff's proposed rate design for TOU-8 rates.

3. Costing Periods for Time-of-Use Rate Schedules

In conformance with the marginal cost methodology established by the Commission in the OII 67 proceeding, it is

necessary to have costing periods for the time differentiation of marginal costs and resulting rate schedules which are based on time-of-use rate design. (D.92749, 5 CPUC 2nd 620 at 638-639.) Edison proposes to modify the existing costing periods applicable to its rate schedules with changes affecting both the seasonal differentiation (reducing summer to the four months of June, July, August, and September and increasing winter to 8 months) and the diurnal periods in both seasons (one hour modifications in several periods). The existing and proposed costing periods are shown below:

Southern California Edison Company
1984 Test Year

Current and Proposed Time-Of-Use Periods

	Current	Proposed
Summer:	Last Sunday in April to Last Sunday in October (6 mos.)	First Sunday in June to first Sunday in October (4 mos.)
On :	1:00 p.m. to 7:00 p.m. weekdays	12:00 p.m. to 6:00 p.m. weekdays
Mid:	9:00 a.m. to 1:00 p.m. 7:00 p.m. to 11:00 p.m. weekdays	8:00 a.m. to 12:00 p.m. 6:00 p.m. to 11:00 p.m. weekdays
Off:	All other hours	All other hours
Winter:	Last Sunday in October to last Sunday in April (6 mos.)	First Sunday in October to first Sunday in June (8 mos.)
On :	5:00 p.m. to 10:00 p.m. weekdays	5:00 p.m. to 9:00 p.m. weekdays
Mid :	8:00 a.m. to 5:00 p.m. weekdays	8:00 a.m. to 5:00 p.m. weekdays
Off :	All other hours	All other hours

(Ex. 53 at 8-1, Table 8-1)

The modifications are based on analyses conducted in accordance with D.92749 using load curves and loss of load probabilities. In the staff's opinion, these modifications were adequately scrutinized to establish that the affected customers would be able to adequately respond to the new periods. Further, the staff has reviewed the proposal, ran its own analyses, and concurs with the changes. Staff has therefore based its rate design and marginal cost analyses on the new costing periods.

For the next general rate case, the staff would like a similar costing period analysis to be performed using marginal costs, rather than loads to characterize the period. Staff witness Haley explained that while she thought the analyses using marginal costs (on an hourly basis) and loads would likely yield similar results, a marginal cost based analysis inherently takes additional relevant factors into account. Apparently computer simulation limitations prevented this analysis from being done in this proceeding.

We find reasonable and will adopt the revised time-of-use costing periods proposed by Edison and endorsed by the staff. We will also adopt staff's suggestion that for the next general rate case a similar costing period analysis should be performed using marginal costs. We also note, as has the staff, that the costing periods adopted in this section do not apply to other areas where seasonal or time differentiation are required such as seasonal divisions for baseline rates and activation periods for direct load control load management programs. While time and season considerations for those programs may, coincidentally, be the same, they are independently determined based on considerations applicable to those programs.

4. Streetlighting

Streetlighting constitutes a separate customer group under Edison's tariffs and is essentially governed by two parallel sets of schedules. The first set of schedules (LS-1, OL-1, and DWL) apply to streetlights which are owned by Edison and for which customers pay a "facilities charge" as a portion of their rates. The second set of schedules includes schedules LS-2 and LS-3 and applies to customers who own their streetlights. An additional schedule, LS-4, provides for Edison to perform maintenance services on streetlights owned by the customer. Most streetlighting customers are on schedules LS-1 and LS-2.

Because of streetlighting's unique characteristics, which have been discussed previously in the Revenue Allocation section of this decision, streetlighting has been an independent customer group. These characteristics, which include a principally off-peak usage pattern, have lead the Commission in this proceeding to continue its policy of excluding the streetlighting group entirely from the Commission's marginal cost revenue allocation process.

With respect to rate design, in the most recent PG&E general rate case decision (D.83-12-068), we observed that our historical treatment of streetlighting rates had resulted in very high rates. An updated cost study (marginal and average) performed by PG&E showed that streetlighting rates should be reduced substantially. In addition to adopting PG&E's proposed reduction in those rates, we directed staff and PG&E to perform an updated cost study for streetlighting for PG&E's next general rate case. We also adopted Cal-SLA's suggestion that PG&E propose an unbundled rate design for streetlighting in its next general rate case.

In this proceeding, Edison has proposed no changes in its current streetlighting schedules. While it is Edison's position that the facilities charges are designed to recover the "rent" due the utility for the use of the streetlights, these charges have not been updated since 1979.

Edison has agreed, however, to perform a streetlighting cost study based on replacement cost less depreciation. The study would be separated by lamp and component parts and would use a November-December 1984 time frame. Edison proposes to include the results of the study as a part of its Energy Cost Adjustment Clause filing for a June 1, 1985 revision date. Edison recommends that in the interim street and area lighting rate levels remain approximately at their present levels. Edison believes that any reduction in rate levels at this time would be inappropriate without a cost study.

The staff recommends that Edison perform a comprehensive cost study for the next general rate case in order for the Commission to more accurately determine facilities costs for streetlights. Among the alternative approaches to developing such a study, staff recommends that the study based on historical costs (embedded or "build up" (an estimated embedded cost study)). According to the staff, the choice of a specific approach should be left somewhat open because of uncertainty regarding the records which Edison has available.

The staff notes that this recommendation should not be viewed as an endorsement of using embedded costs to calculate cost of service generally. Rather, it should be seen as a response to the extremely special nature of facilities charges. In the staff's opinion, marginal cost-based charges would not be appropriate as the rental cost for an appliance leased to a specifically identified customer.

In contrast to the staff and Edison, Cal-SLA recommends (1) that a cost of service study (based on embedded costs) be prepared for use in this proceeding and (2) that alternative means of rate design for streetlighting be considered. In its brief, Cal-SLA recognizes, however, that such a study is unavailable in this proceeding. Cal-SLA, therefore, recommends that, for the interim,

the customer charge and maintenance charges for streetlighting be frozen at current levels. Cal-SLA further indicates that it eagerly awaits the results of Edison's study proposed for its next ECAC reasonableness review proceeding, but continues to urge that such a study be based on embedded costs.

With respect to Cal-SLA's rate design recommendations, Cal-SLA supports the adoption of an "additive" method in this proceeding, with consideration of an "unbundled" method for Edison's next general rate case. The "additive" method essentially requires each of the cost components making up the total rate for the streetlighting schedules to be identified. Thus, the streetlight rate would be structured to include three component charges: an energy charge (based on marginal cost), a customer accounting charge, and all appropriate charges to recover ownership and maintenance costs. These components would be added for each lamp type for a flat monthly charge per lamp. The customer charge and ownership and maintenance charges would be derived from the cost study which Edison would perform. Cal-SLA states that its "additive" approach is similar to that adopted in PG&E's most recent general rate case and will assist streetlighting customers in understanding the nature and basis of their charges.

Cal-SLA also requests that the Commission establish a program in this proceeding which would allow the orderly transfer of utility-owned streetlight facilities to customers who desire to acquire such facilities. Cal-SLA believes that dramatic cost savings to cities and counties would occur were these entities able to acquire and maintain utility-owned streetlights. Cal-SLA acknowledges that these entities currently have the authority to acquire these facilities through condemnation. It is Cal-SLA's opinion, however, that these governmental bodies are reluctant to exercise this authority due to the adversarial nature of the proceeding.

With respect to Cal-SLA's proposals, staff finds two problems with Cal-SLA's additive and unbundled approaches. First, staff asserts that it may be very difficult to disaggregate the individual components of streetlighting costs, particularly to the level of specificity recommended by Cal-SLA. Second, staff states that the unbundled approach may, depending on how it is presented, promote customer misunderstanding as to what individual components represent.

Both staff and Edison object to any "deregulation" (transfer) of streetlights in this proceeding. It is Edison's position that the long-standing condemnation and/or negotiated settlement procedures already in place are the appropriate means for governmental customers to acquire streetlight facilities from Edison. If the Commission desires to address this issue, however, Edison believes that it should do so in a generic OII at which all parties can be heard and a statewide precedent set.

The staff is reluctant to recommend that the Commission become actively involved in streetlight acquisition as Cal-SLA has recommended. If the cost savings are as dramatic as Cal-SLA believes, staff asserts that it would appear to be extremely cost-effective for cities and counties to immediately institute condemnation proceedings. Staff also states that Commission involvement in the valuation process might involve nothing more than ordering the cost studies already recommended by the staff.

With respect to revenue changes between rate cases for the streetlighting class, Edison and staff are in agreement. Both parties support a distribution of revenue requirement among the various schedules based on an equal cents per kilowatt-hour basis.

In the PG&E general rate case, we had before us a current cost of service study for streetlighting which permitted us to reduce rates and adopt a rate design approach similar to Cal-SLA's

additive method. In this proceeding, however, we have yet to be presented with the cornerstone for undertaking revisions of the streetlighting schedule - a current cost of service study. Only when such a study has been completed and reviewed will the Commission be in a position to undertake revisions of streetlighting rate levels and rate design.

To advance this course, we find that a cost of service study should be submitted by Edison as a compliance filing within 180 days of the effective date of this order. This study should be based, as staff has suggested, on historical costs which would include embedded costs, if such records are available, or "build-up" costs. We will direct Edison to update its study prior to its next general rate case and for that proceeding propose alternative rate designs for streetlighting based on both the "additive" and "unbundled" approaches.

In the meantime, the streetlighting rates should be based on current rate levels and rate relationships. Therefore, the decrease in Edison's revenue requirement authorized in this proceeding should be reflected in streetlighting rates on the basis of the system average percentage change of all rates in the aggregate. Any revenue increases occurring between general rate cases should be reflected in streetlighting rates on an equal cents per kilowatt-hour basis as recommended by both the staff and Edison.

We also concur with Edison and staff that Cal-SLA's proposed "deregulation" of streetlights in this proceeding should be rejected. We find insufficient evidence that the current remedies of condemnation or negotiated purchase are either unavailable or inadequate for governmental entities who wish to acquire utility-owned streetlights. Should such a procedure be considered, we agree with Edison that a generic OII would be required to permit a statewide investigation of the shortcomings, if any, of the current

remedy of condemnation, the need for an alternative procedure, and the nature of that procedure.

5. SCRUB

In our section on revenue allocation, we dealt with SCRUB's proposed rate design and revenue allocation for schools. These proposals, as that discussion reflects, were rejected.

SCRUB, however, has made certain additional requests. Specifically, SCRUB asks that the Commission consolidate school district meters for purposes of rate setting and billing. It is SCRUB's belief that such consolidation would lower school district bills by charging the district as a whole rather than individual schools. In addition, consideration of the district as the "customer" would enable more districts to participate in the various load management programs currently available to large customers. SCRUB believes this step is warranted because of the schools being "one of the most highly motivated group of customers who conserve energy." (SCRUB Opening Brief, at p. 15.)

SCRUB also asks that the Commission establish an on-going task force comprised of representatives from school districts, Edison, and the Commission staff. According to SCRUB, the purpose of this task force would be to explore various options for schools in the areas of rate design and load management. SCRUB also requests that the Commission order Edison to be receptive to programs developed in a similar PG&E task force in order to avoid any duplication of efforts by the two groups.

Finally, SCRUB asks that Edison specifically include schools in pilot programs developed for commercial programs, that the Edison's TOU-GS schedule be made available to schools, that Edison use its resources and contacts with school districts to encourage school districts to participate on that schedule, and that an interruptible-type option be made available to schools even if an

individual meter is less than 500 kW. This latter goal could be achieved through consolidated metering and recognition that schools are organized in a manner that would enable them to coordinate their districtwide load and reduce demand when needed.

Staff states that it has not investigated the economics or equities associated with conjunctive billing for schools. Staff believes, however, that irrespective of administrative difficulties, there may be a question of equity in allowing such meter consolidation for schools only. Staff notes that schools are not the only entities who have multiple meters billed to the same party.

Staff also questions SCRUB's assertion regarding schools commitment to conservation. Staff states that the only school district testifying indicated that the conservation improvements which it had undertaken had a payback period of less than 12 months.

Staff does not oppose SCRUB's requests for a task force or involvement in pilot programs. Staff notes, however, that none of SCRUB's witnesses could recall any lack of cooperation on Edison's part in the past.

Edison is more adamant in its opposition to SCRUB's proposal for consolidated meters. Edison states that SCRUB's request to combine all school meters for billing and rate design purposes is specifically prohibited by Edison's tariff Rule 9.B. Further, it is Edison's opinion that such a proposal has the effect of developing preferential rates for schools. Edison believes that, in keeping with this Commission's policy against preferential rates, SCRUB's request for combined meters should be denied.

We find that SCRUB's request for meter consolidation does in fact conflict with our ongoing policy against establishing preferential rates or rate treatment for specific customers or

customer groups. SCRUB has failed to provide sufficient evidence to justify our reversing this policy for schools. We also find an insufficient basis to extend interruptible rates or the TOU-GS schedule to schools. All of these proposals are therefore rejected.

As we did in PG&E's most recent case (D.83-12-068 at p. 372), however, we do find reasonable and support SCRUB's request for a task force, involvement in pilot programs, and coordination of those efforts between utilities and the staff. While the record does not reflect any difficulties in communications between Edison and the school districts, the proposals made by SCRUB will promote a cooperative effort which will hopefully result in the most efficient use of energy by school districts. We will therefore direct the staff and Edison to work with SCRUB with respect to its proposed task force and involvement in pilot programs. We also find reasonable SCRUB's suggested coordination of efforts between Edison's and the PG&E's task forces to avoid any duplication of efforts by the two utilities.

XIV. FINDINGS AND CONCLUSIONS

A. Findings of Fact

1. The adopted results of operations for test year 1985 and each element thereof, as set forth in this opinion, provide a proper and reasonable basis for determining Edison's California jurisdictional base rate revenue requirement.

2. The level of gross revenues produced by Edison's present base rates, including the Annual Major Additions Rate ("AMAR") will exceed Edison's base rate revenue requirement, including the non-investment-related costs associated with San Onofre Units 2 and 3, by $115.8 million in the test year 1985.

3. The capital structure proposed by Edison is found to be reasonable and is as follows:

Debt	45.0%
Preferred Stock	10.0%
Common Equity	45.0%

4. Edison's average imbedded cost of debt and preferred stock for 1985 and 1986 is as follows:

	1985	1986
Long-Term Debt	10.40%	10.25%
Preferred Stock	8.17%	8.17%

5. A return on common equity of 16.00% is reasonable and will afford Edison an opportunity to maintain its financial integrity, to attract capital at a reasonable cost and to compensate investors for the risks assumed over the years 1985, 1986, and 1987.

6. A 16.00% return on common equity when applied to the capital structure described above and added to the debt and preferred stock average costs and yields an average return on rate base for Edison's California jurisdictional operations of 12.70% in 1985 and 12.63% in 1986.

7. To earn an average rate of return of 12.70% in 1985, Edison's Authorized Base Revenue Amount for base rates, contained in the Electric Revenue Adjustment Mechanism ("ERAM") for the Five Major Customer Groups for California jurisdictional electric service should be adjusted effective January 1, 1985 to reflect a base rate revenue requirement level of $2,420,436.

8. The return on rate base together with the other components of the increased base rate revenue requirement are found to be justified and are auth[redacted]understanding that pursuant to the Rate Case Pla[redacted]ear to be used for establishing E[redacted]l be 1988.

9. The[redacted]ast for test year is reasonable.

10. T[redacted]sent base rate levels for 1985 is[redacted]

11. T[redacted]sent base rate levels plus the Ann[redacted]el for 1985 is reasonable.

12. The ad[redacted] for 1985 is reasonable.

13. A 25% redu[redacted]equest for recovery of expenses associated with Edison Electric Institute (EEI) dues is appropriate.

14. The staff recommended adjustment to dues paid by Edison to industrial organizations is reasonable.

15. An additional $454,780 for postage expense in 1985 is reasonable to reflect the postage increase that will go into effect on February 17, 1985.

16. The Stipulation on September 17, 1984 by staff, Edison, and SDG&E related to O&M and A&G expenses for San Onofre Unit Nos. 1, 2, and 3 for 1985, 1986, and 1987 is reasonable. These expenses should be reflected in Edison's and SDG&E's respective results of operations for general rate case and attrition proceedings.

16.a. It is appropriate that the SDG&E Nuclear expense levels, for the common expenses billed by Edison to SDG&E, be set in conjunction with the Edison proceedings to insure consistency of rate treatment. However, SD[redacted]Nuclear expenses should continue to be add[redacted]rate cases.

16.b. The e[redacted]ulation entered into on September 17, [redacted]mission Staff should be adopted s[redacted]f the appropriate labor and nc[redacted]85, 1986, and 1987.

16.c. Ir[redacted]y of expense treatment, i[redacted]consider that portion of SD[redacted]enses billed to SDG&E by Edison in co[redacted]ear 1988 General Rate Case.

16.d. For SDG&E, [redacted]ld adopt for 1985 the appropriate rate increase shown in Late Filed Exhibit 161, Table 1-A of $7,349,000 and the rates calculated based upon this increase in the AMAR.

16.e. For SDG&E, the Commission should adopt revised 1985 Authorized Base Rate Revenues in the ERAM consistent with the rate increases granted in the Amended SDG&E Applications 83-10-12 and 83-11-19.

16.f. The Commission should adopt revised rates in the Amended SDG&E Applications 83-10-12 and 83-11-19 concurrently with Edison's Application 83-12-53 and the rates should be authorized to become effective for SDG&E on January 1, 1985.

CORRECTION

THIS DOCUMENT

HAS BEEN REPHOTOGRAPHED

TO ASSURE LEGIBILITY

7. To earn an average rate of return of 12.70% in 1985, Edison's Authorized Base Revenue Amount for base rates, contained in the Electric Revenue Adjustment Mechanism ("ERAM") for the Five Major Customer Groups for California jurisdictional electric service should be adjusted effective January 1, 1985 to reflect a base rate revenue requirement level of $2,420,436.

8. The return on rate base together with the other components of the increased base rate revenue requirement are found to be justified and are authorized with the understanding that pursuant to the Rate Case Plan the next earliest test year to be used for establishing Edison's revenue requirement will be 1988.

9. The adopted kilowatt-hour sales forecast for test year is reasonable.

10. The adopted estimate of revenue at present base rate levels for 1985 is reasonable.

11. The adopted estimate of revenue at present base rate levels plus the Annual Major Additions Rate (AMAR) level for 1985 is reasonable.

12. The adopted level of O&M expenses for 1985 is reasonable.

13. A 25% reduction to Edison's request for recovery of expenses associated with Edison Electric Institute (EEI) dues is appropriate.

14. The staff recommended adjustment to dues paid by Edison to industrial organizations is reasonable.

15. An additional $454,780 for postage expense in 1985 is reasonable to reflect the postage increase that will go into effect on February 17, 1985.

16. The Stipulation on September 17, 1984 by staff, Edison, and SDG&E related to O&M and A&G expenses for San Onofre Unit Nos. 1, 2, and 3 for 1985, 1986, and 1987 is reasonable. These expenses should be reflected in Edison's and SDG&E's respective results of operations for general rate case and attrition proceedings.

16.a. It is appropriate that the SDG&E Nuclear expense levels, for the common expenses billed by Edison to SDG&E, be set in conjunction with the Edison proceedings to insure consistency of rate treatment. However, SDG&E's in-house Nuclear expenses should continue to be addressed in SDG&E's general rate cases.

16.b. The expense levels shown in the Stipulation entered into on September 17, 1984, by Edison, SDG&E and the Commission Staff should be adopted subject only to future determination of the appropriate labor and non-labor escalation rates for years 1985, 1986, and 1987.

16.c. In order to insure continued consistency of expense treatment, it is appropriate that the Commission consider that portion of SDG&E's 1988 Nuclear O&M and A&G expenses billed to SDG&E by Edison in conjunction with Edison's Test Year 1988 General Rate Case.

16.d. For SDG&E, the Commission should adopt for 1985 the appropriate rate increase shown in Late Filed Exhibit 161, Table 1-A of $7,349,000 and the rates calculated based upon this increase in the AMAR.

16.e. For SDG&E, the Commission should adopt revised 1985 Authorized Base Rate Revenues in the ERAM consistent with the rate increases granted in the Amended SDG&E Applications 83-10-12 and 83-11-19.

16.f. The Commission should adopt revised rates in the Amended SDG&E Applications 83-10-12 and 83-11-19 concurrently with Edison's Application 83-12-53 and the rates should be authorized to become effective for SDG&E on January 1, 1985.

17. Edison and SoCal should embark on a pilot project to investigate the feasibility of Joint Meter Reading. Edison may accrue these costs in an interest bearing memorandum account and seek recovery of such reasonably incurred costs in its next general rate case proceeding. Edison may accrue up to $500,000 dollars of such costs over a three-year period. The project will terminate at the end of 1987. Edison should furnish in its next general rate case proceeding a full report on the results of this project.

18. Edison will implement an Inter-Utility Credit Follow-Up System and provide a report on its efforts in the next general rate case proceeding.

19. Edison's request to recover Lucerne Licensing Costs totaling $7.4 million should be granted. These costs will be amortized over four years; there will be no AFUDC allowed and these costs should be included in the revenue requirement adopted in this proceeding. Edison's rate base estimate is reasonable except that it should reflect the staff method of calculating working cash allowance.

20. The staff's estimate of depreciation accrual rates is reasonable for purposes of this proceeding.

21. Edison's calculation of net-to-gross multiplier is reasonable.

22. Edison's method of calculating jurisdictional allocation is reasonable and should be adopted for purposes of this proceeding.

23. Edison's competitive bidding practices are reasonable. Edison should implement a method to track procurement activities below the $250,000 award level.

24. Edison's recommended modifications to the Female/Minority Business ("F/MBE") program requirements proposed by Staff are reasonable, and will result in an expanded F/MBE program reasonably consistent with the program requirements imposed upon Pacific Bell Company in Decision 84-06-111.

25. The record in this proceeding is insufficient to set F/MBE goals for Edison at this time. However, Edison states that the company "has no problem supporting goals."

26. It is reasonable for Edison to take one year to develop the data base necessary to set goals for its F/MBE program.

27. Edison should work with representative F/MBE development organizations active in Edison's service territory in setting goals for its F/MBE program.

28. Edison should submit a report on development of its F/MBE program goals as part of the filing for its 1988 test year general rate case. Also, Edison should demonstrate the progress it has made in awarding F/MBE contracts in terms of number of contracts and dollar amounts.

29. The additional expense which Edison estimates will be incurred to develop and administer the proposed expanded F/MBE program is reasonable, except that the requested annual increase of $420,000 should be reduced by half for 1985 but the full amount should be allowed in the attrition years.

30. Edison's expanded F/MBE program should be reasonably consistent with the F/MBE requirements of D.84-06-111 by the time of its next general rate case, with the exception of the $5.0 million reporting level and the eight ethnic reporting categories prescribed in that decision. Since such dollar levels could be counter-productive to increasing F/MBE participation in Edison's operations and the evidence on this issue in this proceeding is inconclusive, it is reasonable to defer adoption of dollar reporting levels until Edison's next general rate case proceeding. Also, it is reasonable that, at a minimum, data be collected on the basis of the following ethnic categories: (1) Black; (2) Asian; (3) American Indian; (4) Hispanic; (5) Caucasian White, and (6) All Others. In addition, reporting is required on the basis of "male" or "female".

31. On March 1, 1985 Edison should submit a report to the Commission on its 1984 F/MBE activities.

32. On October 1, 1985, Edison should submit to the Commission a report describing the Company's F/MBE activities in the general categories of Commodities, Construction, and Services, and Other, for the period January 1, 1985 through June 30, 1985. The data contained in the above general categories should be further detailed in corresponding sub-categories for purchase of, or contracts for, similar goods or services.

33. Edison should submit an annual F/MBE activity report to the Commission on March 1 of each year, beginning on March 1, 1986. The annual report shall describe the Company's F/MBE activities for the prior calendar year in detail, and shall set forth the Company's F/MBE contract goals for the current calendar year.

34. Wherever possible, Edison should work with SoCal Gas and other California utilities on the development of a F/MBE data base. Edison and SoCal Gas should consider use of the same contractors so that the ratepayers do not have to pay twice for the utilities to obtain the same data or services.

35. The adopted level of funding for Edison's 1985 test year RD&D program is reasonable.

36. Edison's 1985 RD&D program is consistent with the Commission's stay-the-course policy.

37. Edison should use the reporting format set forth in exhibit 59 appendix E in future RD&D filings for general rate cases.

38. For purposes of this general rate case, it is reasonable to adopt for 1985 the level of expenditure for EPRI expenses equal to the amount billed to Edison in 1984. The amount is $12,911,000.

39. There is a need for a research program to develop a low cost TOU meter. Also it is reasonable to allow Edison to accrue such expenses over a 3-year period up to $1.0 million in an interest bearing memorandum account to fund feasibility studies and preliminary research into development of such a meter. Edison may request recovery of such reasonably incurred expenses, not to exceed $1 million, in its next general rate case proceeding. Funding will cease at the end of 1987 unless the project is extended in Edison's next general rate case proceeding.

40. The adopted level of expenditure for Conservation and Load Management Programs reflects the Commission's stay-the-course policy and is a reasonable level of expenditure for test year 1985.

41. For Commercial/Industrial/Agricultural Conservation programs, Edison should encourage installation of conservation hardware without the requirement of an audit.

42. Edison's conservation and load management department should trim its salary budget, and its entry-level auditor salaries should reflect the job market. Edison should not increase the number of auditors (energy service representatives) beyond end of year 1984 levels. In its next general rate case proceeding, Edison should submit an exhibit to demonstrate that it has effectively reduced its conservation and load management department salary budget from recorded 1984 levels. The exhibit should include a numerical count of employees in the various job classifications, the salary range and qualifications for such classifications. Failure to make a convincing showing on the salary issue should be a sufficient reason to assess a penalty against Edison.

43. It is reasonable to authorize funding for the RCS program through base rates rather than through the Conservation Load Management Adjustment Clause.

44. A funding level of $5.1 million is reasonable for the 1985 RCS program. The 1986 RCS budget should be reduced by $1.0 million and the budget for 1987 reduced by an additional $1.0 million. These funds should be shifted to encourage the placing of more conservation hardware in the residential and small commercial and industrial sectors.

45. It is reasonable to fund the expenses associated with the Solar OII-42 Program through base rates rather than through the Conservation Load Management Adjustment Clause.

46. It is reasonable to maintain our current policy and consider funding for the refrigerator component of the Residential Conservation Financing Program through the Conservation Load Management Adjustment Clause.

47. Official notice is taken of the CEC order directing Edison to continue its residential air-conditioner cycler program at a rate of 24,000 units per year for 1985 and 1986.

48. General conservation advertising costs should be kept to a minimum and the staff recommendation of $535,000 for 1985 is reasonable.

49. The discretion previously granted, which permits Edison to reallocate $2.5 million within each of the Residential Conservation, CIA Conservation, and Load Management categories, is reaffirmed.

50. It is not reasonable to fund the New Construction Load Management Program at this time.

51. Further studies are needed to determine Edison's optimal or appropriate level of system reliability.

52. Changes made with respect to contingent retirements between Edison's Fall 1982 and Fall 1983 resource plans are reasonable.

53. Edison's performance with respect to developing cogeneration and small power production is reasonable.

54. The goals set by Edison are reasonable and constitute an aggressive effort to pursue alternative and renewable resources.

55. Edison's request for its 1985 cogeneration and small power production program expense is reasonable.

56. Marginal cost remains an important factor for determining adopted cost recovery by customer group.

57. Avoided cost pricing has been adopted by the Commission and dictated by the Federal Government for use in developing payments to qualifying facilities.

58. It is reasonable for the Commission to continue to use marginal and avoided costs for allocating Edison's revenue requirement between customer classes, determining the design of specific rates, measuring the cost-effectiveness of conservation and load management programs, and calculating utility payments to qualifying facilities.

59. It is appropriate for the Commission in this proceeding to continue to base marginal cost ratemaking and QF pricing on the short-run economic time-frame.

60. It is reasonable to apply the same short-run marginal cost methodology for all ratemaking and QF pricing purposes for which marginal and avoided costs are used. This approach ensures the equal treatment of the utility, its customers, and qualifying facilities. A single methodology should also enhance comprehension of the adopted approach.

61. The methodology adopted to calculate marginal costs should be the one which most accurately reflects the utility's avoided and marginal costs.

62. The accuracy of the costs and assumptions adopted by this Commission in determining a utility's marginal costs are critical for all purposes for which such costs are used.

63. It is reasonable to adopt a methodology for calculating marginal costs based on a forecast of those costs. By doing so, the rates and prices in effect in the test year will most accurately reflect the test year, not past year, conditions.

64. Despite advantages of simplicity and verifiability, Edison's alternate proposal for QF energy pricing fails to provide a methodology applicable to all purposes for which marginal and avoided energy costs are used and relies on recorded, as opposed, to forecasted data. Such an alternate is inconsistent with this Commission's policies on marginal energy costs and should be rejected.

65. Guidelines adopted by this Commission for access to utility computer models should minimize the "black box" aspect of marginal cost calculations performed by computer models.

66. Staff's suggestion for a generic OII into the subject of a uniform, statewide computer model has merit.

67. A computer model approach is reasonable for use in developing Edison's final marginal and avoided energy costs.

68. To ensure that the resulting marginal energy costs most accurately reflect test year conditions, the following adjustments in Edison's PROMOD assumptions are reasonable and should be made:

- The appropriate resource mix to be used in the marginal energy calculation is that existing at the commencement of the test year. Under these circumstances, Palo Verde Nuclear Generating Station Unit 1 (PVNGS 1) should be excluded from the resource assumptions, while, based on current estimates of operation in 1985, SONGS 1 should be included.
- The updated peak demand level reflected in Edison's resource plan (13,860 mW) should be used in deriving Edison's IER.

- Edison's IER should be based on an estimate of fuel costs of $5.07/mmbtu.
- Edison should alter other input assumptions to reflect, as IEP has proposed, the hydro quantities stated in its ECAC filing, A.84-02-11; the figures for the availability of purchased power developed for the same ECAC filing, the estimates for the performance of SONGS 1, 2, and 3 also presented in A.84-02-11; a 66 percent production factor for PVNGS 2; and a load forecast based on Edison's demand forecast in A.84-02-11.

69. It is reasonable for this Commission to rely on Edison's use of its PROMOD model to calculate its marginal energy costs and to follow the methodology which Edison proposed for calculating those costs in the off-peak period and Edison's "zero intercept" methodology for the on- and mid-peak periods.

70. It is reasonable to include working cash capital, but not administrative and general (A&G) expenses, in the calculation of both marginal energy costs and avoided energy costs.

71. To expedite the review and enhance the understanding of utility rate increase applications, all utilities should be required to provide computer input and output data supporting their exhibits simultaneously with the filing of their applications. It is reasonable to direct Edison to undertake this task in its next general rate case filing and to consider applying the same rule to other utilities by resolution.

72. The staff's proposed Reliability Adjustment Factor (RAF) to be applied to the value of the combustion turbine used in the calculation of Edison's marginal capacity costs is technically flawed. These flaws preclude the Commission from making the same findings with respect to the RAF which permitted our adoption of PG&E's ERI adjustment factor in PG&E's most recent general rate case.

73. The Commission continues to support the conceptual merit of any adjustment mechanism or other device which can, if adequately supported, provide the most accurate determination of marginal or avoided costs.

74. Based on the record in this proceeding, the Commission is required to adopt the methodology proposed by Edison and the staff to calculate marginal costs of demand and QF capacity prices based on the unadjusted annualized value of the combustion turbine.

75. Edison's proposed real inflation rate of 7 percent is reasonable and should be adopted for use in the final calculation of the marginal cost of demand and QF capacity prices.

76. The staff's and Edison's approaches to the conversion of marginal costs of demand to class responsibility are not substantially different from each other and follow the basic methodology adopted in previous rate cases.

77. Staff's approach to the conversion referenced above is an appropriate means of putting the theory of marginal cost ratemaking into practice and of determining class marginal demand costs in an effective manner. It is therefore reasonable to adopt this approach in this proceeding.

78. It is reasonable to continue to exclude marginal customer costs from the calculation of total marginal costs for the reasons discussed in this decision.

79. A weighted average method of allocation consisting of 95 percent of the System Average Percentage Change (SAPC) approach and 5 percent of the Equal Percent of Marginal Cost (EPMC) approach is a reasonable and appropriate method of allocating Edison's revenue requirement among the various customer classes.

80. The impact on Edison's residential customers is significantly less if revenue is allocated on a weighted average basis rather than a full EPMC basis.

80a. Since Baseline, Interruptable, and Time of Use rate designs are to be implemented in May and June 1985 respectively, for the rates to be made effective on January 1, 1985, the domestic lifeline/non-lifeline and all time of use rate levels shall be increased so as to approximately maintain their existing percentage relationships.

81. The unique characteristics of the streetlighting customer class support the continuation of this Commission's policy of excluding that group entirely from the marginal cost revenue allocation process.

82. The proposals of the Schools Committee to Reduce Utility Bills (SCRUB) for a separate revenue allocation approach for schools would require this Commission to single out schools from other customers without adequate cause and to develop rates for schools based on an approach contrary to basic ratemaking principles and established Commission policy. SCRUB's proposals should therefore be rejected.

83. It is reasonable to adopt the System Average Percentage Change (SAPC) method for allocating revenue changes in offset proceedings which take place between Edison's general rate cases. This methodology should be applied to those customer classes for which marginal costs have been adequately developed and utilized as a revenue allocation principle in this proceeding. The proportional relationships within those customer classes should also be maintained.

84. Consistent with established Commission policy, present rate revenues should be based on rate levels actually in effect just prior to any change in revenue level authorized in this proceeding. This approach, followed by the staff, should be adopted in this proceeding.

85. Every aspect of any rate design proposal and its consistency with stated Commission policy and accepted ratemaking principles are considered in determining whether to adopt or reject such a proposal.

86. The staff's basic approach to baseline is reasonable and consistent with applicable statutory guidelines and should be adopted, except as otherwise modified in this decision.

87. It is reasonable to adopt Edison's alternate three-year phase-in of baseline as described in Exhibit 146, modified to include a 200 kWh cap on the amount of the decrease which could be experienced by any of Edison's customers in a single year. It is also reasonable for Edison to classify all customers who are presently being billed with an electric water heating allowance as all-electric customers as we did in D.84-11-026 for PG&E.

88. In this proceeding, both staff and Edison have made proposals designed to respond to the special needs of Climate Zone 15 residents and the statements of the Coachella Valley Association of Governments (CVAG) made during Public Hearing. Each has made baseline proposals which not only follow the established guidelines for determining baseline quantities, but provide the seasonally varying baseline quantities sought by CVAG. These proposals include staff's Climate Zone 15 proposal and Edison's alternative four-month summer/eight-month winter baseline quantitites.

89. The needs of Climate Zone 15 residents can be adequately met at the present time by adopting both the climate zone proposed by staff and Edison and the baseline quantities proposed by the staff utilizing its four-month summer/eight-month winter approach.

90. It is appropriate to take whatever steps are available to permit all residents the opportunity to realize, to the extent possible, the benefits of baseline.

91. It is reasonable to extend the baseline allowance to "residential units" in Edison's service area as that term is defined in D.83-12-068 (pp. 372-373). It is reasonable to direct Edison to file a plan for applying baseline allowances to residential hotels, for identifying residential hotels in its service area, and for coordinating its efforts with local governments and organizations. This plan can also include an indication of the percentage of residential hotels which fall within Edison's current definition of domestic service and of the feasibility and costs associated with a residential hotel segregating its electric service between that supplied for domestic purposes and that supplied for commercial purposes.

92. Based on the results of recent Edison studies and Edison's implementation of daily baseline allowances, it is reasonable to continue Edison's current practice and method of prorating the transition between seasonal baseline allowances.

93. Staff's proposed two-tier residential rate design is reasonable and should be adopted. The adopted percentage governing the rate levels in each tier should be maintained, to the extent possible, between Edison's general rate cases.

94. It is reasonable for the problems of customer migration between rate schedules, if any exist, to be addressed by appropriate additions or revisions to current tariff language.

95. Prior to the transition to baseline in May 1985, it is reasonable to apply the residential rate spread in effect prior to January 1, 1985, to the lifeline quantities. Any increase or decrease in residential class revenues resulting from this decision should be allocated to lifeline and non-lifeline tiers on a straight percentage basis maintaining the current relationship of those tiers.

96. Rate neutrality between time-of-use and standard rates is an appropriate consideration in developing the rate design for TOU rates.

97. The staff's recommended changes of Edison's proposed TOU-D rates are reasonable. The rate design proposed by the staff not only achieves rate neutrality, but ensures, when coupled with staff's recommended meter charge, the equitable treatment of all residential ratepayers.

98. Staff's calculation of the daily discount for Edison's DMS-1 schedule is reasonable and should be adopted.

99. The present methodology for calculating the discount for the DMS-2 schedule yields a discount which will properly compensate mobile home park customers and be reasonable for Edison's ratepayers. Adoption of the methodology proposed by the staff is not warranted at this time.

100. The methodology for calculating the DMS-2 discount which the Commission adopted in C.10273 is not completely static. In particular, the definition of average costs of the utility can change especially in the event of Commission action. These changes must necessarily be taken into account in the calculation of the discount.

101. Edison's revised DMS-2 study contained in Exhibit 127 is the most appropriate basis for determining the monthly discount to which master meter customers are entitled for each submeter. The $7.26 monthly cost per unit contained in that exhibit should be adjusted to reflect the rate of return adopted in this decision.

102. It is reasonable to implement Edison's proposed daily rates for non-demand rate schedules, with one exception. There is insufficient justification in this record for switching streetlighting customers to daily rates, either on a deferred or immediate basis.

103. There is no basis to increase the minimum charge for Schedule GS-2.

104. Any authorized increases or decreases in Edison's revenue requirement should be reflected solely in the energy charges for the GS-1 and GS-2 schedules on an equal cents per KWh basis.

105. No evidence has been presented in this proceeding to justify the setting of irrigation rates at the same levels as baseline rates.

106. The objective of time-of use rates is to encourage the shifting of load or electrical usage from peak periods of high demand to periods of lesser demand. This load shifting is designed to promote the optimum use and efficiency of existing electric plants.

107. Time of use rates provide more accurate price signals to the consumer when they are based on the utility's marginal costs.

108. No party to this proceeding, other than the Commission staff, has consistently attempted to modify existing rate schedules in keeping with the dual goals of time of use rates — plant efficiency (the encouragement of load shifting) and economic efficiency (the development of marginal cost-based prices).

109. The following modifications proposed by the staff for the TOU-8 rate schedule are reasonable and in keeping with Commission policy: (1) a non-time-differentiated flat demand charge with all rate increases or, in this case, rate decreases reflected in the energy charge and (2) seasonally differentiated time-of-use rates and a minimum charge.

110. Because of the impact of the changes recited above on TOU-8 customers, it is reasonable to delay the implementation of the new TOU-8 rate design until the first seasonal transition in the test year.

111. The staff has appropriately suggested a restructuring of Edison's interruptible rates for TOU-8 customers. In adopting any such restructuring, however, the Commission must ensure that sufficient incentives exist for those customers to agree to such changes in their electrical supply. This incentive is provided by adopting staff's revision of Schedules I-3 and I-4, while retaining Schedules I-1 and I-2. It is reasonable to modify staff's recommended "zero notice" option, however, to provide the credit incentives proposed by the California Large Energy Consumers Association (CLECA) and the 180-hour limit per year on the periods of curtailment.

112. All of the interruptible schedules adopted in this decision shall be reexamined as to their impact and customer acceptance in Edison's next general rate case.

113. Revision of Edison's voltage discounts for TOU-8 customers is required.

114. Staff's proposed two-step approach to the revision of TOU-8 voltage discounts is reasonable. For this proceeding, it is reasonable to adopt staff's recalculated voltage discounts for each of the three voltage categories of below 2 kV, 2 kV to 50 kV, and greater than 50 kV. For Edison's next general rate case, it is reasonable to direct Edison to file with its application a TOU-8 rate schedule divided into the three subgroups listed above, with rates based on marginal costs developed for each of those subgroups.

115. It is the continuing policy of this Commission that no customer should be granted exemptions from mandatory TOU-8 rates. No compelling evidence has been presented in this proceeding to alter this policy.

116. For the agricultural time-of-use rates, it is reasonable to close the current TOU-PA-1, to make permanent and open to all members of the agricultural class on a voluntary basis TOU-ALMP-2, and to continue on an experimental basis until Edison's next general rate case TOU-ALMP-1. In that proceeding, it is reasonable for the Commission to reexamine TOU-ALMP-1 and determine whether to close it, modify it, or continue it on a permanent basis.

117. The time-of-use tariffs presently in effect for agricultural customers have costing periods which correspond to the three usage periods on Schedule TOU-8. The off-peak period for Schedule TOU-PA-1 is the same as the off-peak period for Schedule TOU-9 while the on-peak period for this schedule covers both the on- and mid-peak periods of Schedule TOU-8. This policy should be continued in revising the costing periods for the adopted agricultural time-of-use schedules.

118. Staff proposed rate designs for Schedules TOU-GS and TOU-8 are reasonable, except to the extent modified in this decision, and should be adopted.

119. The revised time-of-use costing periods proposed by Edison and endorsed by the staff are reasonable and should be adopted.

120. It is reasonable to require Edison to perform a similar costing period analysis undertaken in this proceeding, but using marginal costs, in its next general rate case application.

121. Only when a current-cost of service study for streetlighting has been completed and reviewed can the Commission undertake revisions of streetlighting rate levels and rate design.

122. It is reasonable to require Edison to submit a cost of service study for streetlighting as a compliance filing within 180 days of the effective date of this order. This study should be based on historical costs or "build-up" costs as recommended by the staff. Edison should also be required to update this study and propose alternative rate designs for streetlighting based on both the "additive" and "unbundled" approaches as part of its next general rate case application.

123. For this proceeding, it is reasonable to base streetlighting rates on current rate levels and rate relationships. Any decrease in Edison's revenue requirement authorized in this proceeding should be reflected in streetlighting rates on the basis of the system average percentage change of all rates in the aggregate. Any revenue inceases occurring between general rate cases should be reflected in streetlighting rates on an equal cents per kilowatt-hour basis as recommended by both the staff and Edison.

124. It is not appropriate to adopt Cal-SLA's proposed "deregulation" of streetlights in this proceeding. Insufficient evidence has been presented indicating that current remedies are inadequate. Consideration of such a proposal would require a statewide investigation applicable to all utilities.

125. SCRUB's request for meter consolidation for school districts conflicts with the Commission's ongoing policy against establishing preferential rates or rate treatment for specific customers or customer groups. SCRUB has failed to provide sufficient evidence to justify a reversal of this policy for schools.

126. There is an insufficient basis to extend interruptible rates or the TOU-GS schedules to school districts.

127. SCRUB's request for a task force, involvement in pilot programs, and coordination of these efforts between utilities and the staff are reasonable and should be adopted.

128. The residential rates discussed herein and shown in the Rate Appendix D are reasonable.

129. The nonresidential rates discussed herein and shown in Rate Appendix D are reasonable.

130. This order should be effective as of the date of signature because the rates covered by this opinion need to be in effect on January 1, 1985.

131. Since the Commission has changed from a two-year to a three-year Rate Case Plan, Edison should file exhibits and prepared testimony setting forth its proposals for an attrition mechanism on or before April 15, 1985.

B. Conclusions of Law

1. Edison should be authorized to file the revised electric rates which are set forth in Appendix D and which are designed to produce $2,462,488,000 revenues based on the adopted test year 1985 results of operations.

2. Edison's attrition allowance for 1986 and 1987 should be considered in separate evidentiary hearings to be held during 1985 following issuance of this opinion. Accordingly, this opinion covers rates for 1985 only.

3. All transcript corrections received are incorporated in the record.

4. All motions not specifically ruled upon are denied.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission, on or after the effective date of this order, revised tariff schedules for electric rates as set forth in Appendix D attached hereto and by this reference made a part hereof.

2. The revised tariff schedules shall become effective on the date of filing but not earlier than January 1, 1985, and shall comply with General Order 96-A.

3. The revised rate schedules shall apply to service rendered on or after the effective date of the revised tariff schedules.

4. Edison shall furnish all reports and filings as discussed in this opinion.

5. By January 31, 1986, Edison shall, after meeting with authorized representatives of recognized minority groups, draft and submit to the Commission for its approval, a tracking procedure that comprises:

a. Stated calendar year 1986 F/MBE contract goals for the following ethnic classifications:

Black
Asian
American Indian
Hispanic

Data for each of the above ethnic classifications is to be further categorized as either "male" or "female". Until such time as Edison's next general rate case proceeding, these contract goals are to be developed and applied in a manner which is consistent with Edison's current competitive procedurement practices.

b. On March 1, 1985 Edison shall submit to the Commission a report detailing its 1984 F/MBE activities. Since Edison's data base will not be ready in time for this report, there will be no prescribed format.

c. On October 1, 1985, Edison shall submit to the Commission a report describing the Company's F/MBE activities in the general categories of Commodities, Construction, and Services and Other, for the period January 1, 1985 through June 30, 1985. The data contained in the above general categories shall be further detailed in corresponding sub-categories for purchase of, or contracts for, similar goods or services.

d. Edison shall submit an annual F/MBE activity report to the Commission on March 1, of each year, beginning on March 1, 1986. The annual report shall describe the Company's F/MBE activities for the prior calendar year in the detail set forth in sub-paragraph c, and shall set forth the Company's F/MBE contract goals by the general categories of Commodities, Construction, and Services and Other, for the current calendar year.

6. At the time of its next rate case filing, Edison shall provide to all parties the computer input and output data supporting exhibits included in the application.

7. Edison shall classify all customers who are presently being billed with an electric water heating allowance as all-electric customers in the same manner specified in Decision (D.) 84-11-026 for Pacific Gas and Electric Company.

8. Within 180 days of the effective date of this order, Edison shall submit a compliance filing with the Commission of its plan for applying baseline allowances to residential hotels. This plan shall also identify residential hotels in Edison's service territory and

propose a plan for Edison coordinating its efforts with local governments and organizations. The plan can also include an indication of the percentage of residential hotels in Edison's service territory which fall within its definition of domestic service and the feasibility and costs associated with a residential hotel segregating its electric service between that supplied for domestic purposes and that supplied for commercial purposes.

9. As part of its next general rate case application, Edison shall file a TOU-8 rate schedule divided into three subgroups based on the voltage categories of below 2 kV, 2 kV to 50 kV, and greater than 50 kV. This schedule shall include rates based on marginal costs developed for each of those subgroups.

10. As part of its next general rate case application, Edison shall include a costing period analysis for the TOU-8 rate schedule which shall be similar to that performed for this proceeding, but shall be performed using marginal costs.

11. Within 180 days of the effective date of this order, Edison shall submit a compliance filing with the Commission of a cost of service study for the streetlighting customer class. This study shall be based on historical costs, if adequate records are available, or "build up" costs. This study shall be updated prior to Edison's next general rate case proceeding. As part of Edison's next general rate case filing, Edison shall propose alternative rate designs for streetlighting based on both the "additive" and "unbundled" approaches.

12. In its next general rate case proceeding, Edison shall provide a convincing showing that it has reduced its conservation and load management department salary budget from recorded 1984 levels. Failure to provide such a showing will be a sufficient reason to assess a penalty against Edison.

13. Edison shall file exhibits and prepared testimony setting forth its proposals, for a first and second year attrition mechanism, on or before April 15, 1985. Hearing on this matter will be scheduled for mid-1985 and this proceeding will remain open for that purpose.

14. San Diego Gas & Electric Co. (SDG&E) is authorized to file revised electric rates to reflect Nuclear O&M expenses billed by Edison to SDG&E as set forth in late-filed Exhibit 161, Table 1-A. The new rates shall become effective on the date of filing but not earlier than January 1, 1985 and shall comply with General Order 96-A.

This order is effective today.

Dated December 28, 1984, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
PRISCILLA C. GREW
WILLIAM T. BAGLEY
FREDERICK R. DUDA
Commissioners

We will file a written dissent in part.

/s/ VICTOR CALVO
Commissioner

/s/ PRISCILLA C. GREW
Commissioner

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

Joseph E. Bodovitz, Executive Director

List Of Appearances

Applicant: Richard K. Durant, Frank J. Cooley, James M. Lehrer, Stephen E. Pickett, and Larry C. Mount, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Harry K. Winters, for University of California; William B. Marcus, by Janice G. Hamrin, for Independent Energy Producers; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr, Attorney at Law, for General Motors Corporation and Union Carbide Corporation; Elmer W. Johnson, General Counsel; Julius Jay Hollis, Attorney at Law; John W. Witt, City Attorney, by William S. Shaffran, Deputy City Attorney, for City of San Diego; William L. Knecht, Attorney at Law, for California Association of Utility Shareholders; Biddle & Hamilton, by Richard L. Hamilton and Halina Osinski, Attorneys at Law, for Western Mobilehome Association; William L. Reed, Randall W. Childress, and Jeffrey Lee Guttero, Attorneys at Law, for San Diego Gas & Electric Company; Steven A. Geringer, Attorney at Law, for California Farm Bureau Federation; Petty, Andrews, Tufts & Jackson, by Allan J. Thompson, Attorney at Law, for California Large Energy Consumers Association; Michael Peter Florio, Jon F. Elliott, and Robert Spertus, Attorneys at Law, and Sylvia M. Siegel, for Toward Utility Rate Normalization; Brobeck, Phleger & Harrison, by Gordon E. Davis, William H. Booth, and Richard C. Harper, Attorneys at Law, for California Manufacturers Association; Henwood Associates, Inc., by David R. Branchcomb, for Henwood Associates, Inc.; Norman J. Furuta and Gilbert H. Chong, Attorneys at Law, for Federal Executive Agencies; Jeffrey A. Meith, Attorney at Law, Donald G. Salow, and James F.

Sorensen, for Association of Water Agencies and Friant Water Users Association; Sutherland, Ashbill & Brannan, by Edward J. Grenier, Jr. and Earl H. O'Donnell, Attorneys at Law, for Federal Paperboard Company; Kronick, Moskovitz, Tiedman & Girard, by Diana D. Halpenny, Attorney at Law, and Steven R. Cranfill, for Schools Committee for Reducing Utility Bills; McCracken, Antone & Camerlengo, by Michael McCracken, Attorney at Law, and Reed V. Schmidt, for California City-County Street Light Association; Hanna and Morton, by Douglas K. Kerner, R. Lee Roberts, Attorneys at Law, and Mark Lyons, for Occidental Geothermal, Inc. and Ultrasystems, Inc.; Steven M. Cohn, Attorney at Law, for the California Energy Commission; Greve, Clifford, Diepenbrock & Parks, by Douglas L. Youmans and Thomas S. Knox, Attorneys at Law, for California Retailers Association; Chadbourne, Parke, Whiteside & Wolff, by Jerry R. Bloom, Attorney at Law, and Wayne Meek, for Simpson Paper Company; O'Donnell, Waiss, Wall & Meschke, by Fredrik S. Waiss, Attorney at Law, for Stauffer Chemical Company; Matthew Brady, Attorney at Law, for State Energy Assessment Program; Dan Richard, Attorney at Law, for Independent Energy Producers Association; Sara Hoffman, for County of Contra Costa; Robert Gnaizda, Attorney at Law, and Elizabeth Clark, for Black Chamber of Commerce, et al.; and Edward Duncan, for himself.

Commission Staff: Thomas P. Corr and Philip Scott Weismehl, Attorneys at Law, Ida Goalwin, and Edmund J. Texeira.

(END OF APPENDIX A)

APPENDIX B
Page 1

SOUTHERN CALIFORNIA EDISON COMPANY
Operating Revenues At Present Rates
(Including Songs Unit 1)
Test Year 1985

RESULTS OF OPERATIONS

(Thousands Of Dollars)

Line No.	Description	Adopted	SCE	Adopted Exceeds SCE Amount	Percent
		(A)	(B)	(C=A-B)	(D=C/B)
1	Domestic	830,134	827,761	2,373	.3%
2	Lighting - Small & Medium Power	881,759	875,770	5,989	.7%
3	Large Power	702,619	700,088	2,531	.4%
4	Agricultural & Pumping	71,332	71,098	234	.3%
5	Street & Area Lighting	50,280	50,264	16	.0
6	Subtotal	2,536,224	2,525,081	11,143	.4%
	CPUC Jurisdictional Other				
7	Fringe	297	297	0	.0
8	NMD	7	7	0	.0
9	Other Operating Revenue	27,814	27,814	0	.0
10	Subtotal	28,118	28,118	0	.0
11	Total CPUC Jurisdictional	$2,564,342	$2,553,199	11,143	.4%
	Resale				
12	TDU-R	125,132	125,150	(18)	.0
13	Resale - Special	1,270	1,270	0	.0
14	Other Operating Revenues	14,390	14,390	0	.0
15	Subtotal	140,792	140,810	(18)	.0
16	Total Operating Revenues	$2,705,134	$2,694,009	11,125	.4%

SOUTHERN CALIFORNIA EDISON COMPANY
Steam Production Expense
Test Year 1985

(Thousands Of Dollars)

Line No.	Account No.	Description	RRD (A)	SCE (B)	SCE Exceeds RRD Amount (C=B-A)	SCE Exceeds RRD Percent (D=C/A)
		Operation				
1	501.0	Supervision & Engineering	6,118	5,587	(531)	(8.7%)
2	502.0	Fuel Related Expense	20,050	21,692	1,642	8.2%
3	503.0	Steam Expenses	12,872	15,141	2,269	17.6%
4	505.0	Electric Expenses	6,816	6,980	164	2.4%
5	506.0	Misc Steam Expenses	12,831	13,968	1,137	8.9%
6	506.0	RD&D	15,514	15,989	475	3.1%
7	507.0	Rents	218	218	0	.0
8		Total Operation	$74,419	$79,575	$5,156	6.9%
		Maintenance				
9	510.0	Supervision & Engineering	12,488	11,053	(1,435)	(11.5%)
10	511.0	Maintenance of Structures	5,363	4,708	(655)	(12.2%)
11	512.0	Maintenance of Boiler Plant	50,262	58,152	7,890	15.7%
12	513.0	Maintenance of Electric Plant	25,649	25,612	(37)	(.1%)
13	514.0	Maint of Misc Steam Plant	6,140	8,582	2,442	39.8%
14		Total Maintenance	$99,902	$108,107	$8,205	8.2%
15		TOTAL STEAM PRODUCTION	$174,321	$187,682	$13,361	7.7%
		Escalation Amounts				
16		Labor	9,099	9,667	568	6.2%
17		Non-Labor	12,244	13,788	1,544	12.6%
18		Other	0	0	0	.0
19		Total	$21,343	$23,455	$2,112	9.9%
20		TOTAL STEAM (1985 Dollars)	$195,664	$211,137	$15,473	7.9%

SOUTHERN CALIFORNIA EDISON COMPANY
Steam Production Operation Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	RRD (A)	SCE (B)	SCE Exceeds RRD (C=B-A)	Line No.
	500.0	Supervision & Engineering				
1		Labor	$5,455	$4,935	($520)	1
2		Non-Labor	663	652	(11)	2
3		Other	0	0	0	3
4		Total	6,118	5,587	(531)	4
	501.0	Fuel Related Expense				
5		Labor	3,020	3,047	27	5
6		Non-Labor	8,720	10,335	1,615	6
7		Other	8,310	8,310	0	7
8		Total	20,050	21,692	1,642	8
	502.0	Steam Expenses				
9		Labor	3,231	3,304	73	9
10		Non-Labor	9,641	11,837	2,196	10
11		Other	0	0	0	11
12		Total	12,872	15,141	2,269	12
	505.0	Electric Expenses				
13		Labor	5,119	5,066	(53)	13
14		Non-Labor	1,697	1,914	217	14
15		Other	0	0	0	15
16		Total	6,816	6,980	164	16
	506.0	Misc Steam Expenses				
17		Labor	8,931	5,539	(3,392)	17
18		Non-Labor	3,900	8,429	4,529	18
19		Other	0	0	0	19
20		Total	12,831	13,968	1,137	20
	506.0	RD&D				
21		Labor	1,830	1,947	117	21
22		Non-Labor	13,684	14,042	358	22
23		Other	0	0	0	23
24		Total	15,514	15,989	475	24
	507.0	Rents				
25		Labor	0	0	0	25
26		Non-Labor	0	0	0	26
27		Other	218	218	0	27
28		Total	218	218	0	28
		Total Operation				
29		Labor	27,586	23,838	(3,748)	29
30		Non-Labor	38,305	47,209	8,904	30
31		Other	8,528	8,528	0	31
32		Total	$74,419	$79,575	$5,156	32

SOUTHERN CALIFORNIA EDISON COMPANY
Steam Production Maintenance Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	RRD (A)	SCE (B)	SCE Exceeds RRD (C=B-A)	Line No.
	510.0	Supervision & Engineering				
1		Labor	$7,043	$9,373	$2,330	1
2		Non-Labor	5,445	1,680	(3,765)	2
3		Total	12,488	11,053	(1,435)	3
	511.0	Maintenance of Structures				
4		Labor	1,019	783	(236)	4
5		Non-Labor	4,344	3,925	(419)	5
6		Total	5,363	4,708	(655)	6
	512.0	Maintenance of Boiler Plant				
7		Labor	7,774	8,373	599	7
8		Non-Labor	42,488	49,779	7,291	8
9		Total	50,262	58,152	7,890	9
	513.0	Maintenance of Electric Plant				
10		Labor	6,475	6,325	(150)	10
11		Non-Labor	19,174	19,287	113	11
12		Total	25,649	25,612	(37)	12
	514.0	Maint of Misc Steam Plant				
13		Labor	708	758	50	13
14		Non-Labor	5,432	7,824	2,392	14
15		Total	6,140	8,582	2,442	15
		Total Maintenance				
16		Labor	23,019	25,612	2,593	16
17		Non-Labor	76,883	82,495	5,612	17
18		Total	$99,902	$108,107	$8,205	18
		TOTAL STEAM PRODUCTION				
19		Labor	50,605	49,450	(1,155)	19
20		Non-Labor	115,188	129,704	14,516	20
21		Other	8,528	8,528	0	21
22		Total (1982 Dollars)	$174,321	$187,682	$13,361	22
		Escalation Amounts				
23		Labor	9,099	9,667	568	23
24		Non-Labor	12,244	13,788	1,544	24
25		Other	0	0	0	25
26		Total	$21,343	$23,455	$2,112	25
		TOTAL STEAM PRODUCTION				
27		Labor	59,704	59,117	(587)	27
28		Non-Labor	127,432	143,492	16,060	28
29		Other	8,528	8,528	0	29
30		Total (1985 Dollars)	$195,664	$211,137	$15,473	30

APPENDIX B
Page 5

SOUTHERN CALIFORNIA EDISON COMPANY
Nuclear Production Expense
Test Year 1985

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted	SCE	SCE Exceeds Adopted Amount	SCE Exceeds Adopted Percent
			(A)	(B)	(C=B-A)	(D=C/A)
		Operation				
1	517.0	Supervision & Engineering	31,158	31,158	0	.0
2	518.0	Nuclear Fuel Expense	1,031	1,031	0	.0
3	519.0	Coolants and Water	4,478	4,478	0	
4	520.0	Steam Expenses	12,444	12,444	0	.0
5	522.0	Electric Expenses	1,476	1,476	0	.0
6	524.0	Misc Steam Expenses	38,285	38,285	0	.0
7	524.0	ROAD	173	253	80	46.2%
8	525.0	Rents	124	124	0	.0
9		Total Operation	$89,169	$89,249	$80	.1%
		Maintenance				
10	510.0	Supervision & Engineering	23,138	23,138	0	.0
11	511.0	Maintenance of Structures	2,862	2,862	0	.0
12	512.0	Reactor Plant Equipment	8,459	8,459	0	.0
13	513.0	Electric Plant	9,441	9,441	0	.0
14	514.0	Miscellaneous Nuclear Plant	3,530	3,530	0	.0
15		Total Maintenance	$48,490	$48,490	$0	.0
16		TOTAL NUCLEAR PRODUCTION	$137,659	$137,739	$80	.1%
		Escalation Amounts				
17		Labor	8,164	8,879	715	8.8%
18		Non-Labor	8,161	8,169	8	.1%
19		Other	0	0	0	.0
20		Total	$16,325	$17,048	$723	4.4%
21		TOTAL NUCLEAR (1985 Dollars)	$153,984	$154,787	$803	.5%

SOUTHERN CALIFORNIA EDISON COMPANY
Nuclear Production Operation Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted (A)	SCE (B)	SCE Exceeds Adopted (C=B-A)	Line No.
	517.0	Supervision & Engineering				
1		Labor	$13,812	$13,812	$0	1
2		Non-Labor	17,346	17,346	0	2
3		Other	0	0	0	3
4		Total	31,158	31,158	0	4
	518.0	Nuclear Fuel Expense				
5		Other	1,031	1,031	0	5
6		Total	1,031	1,031	0	6
	519.0	Coolants and Water				
7		Labor	1,356	1,356	0	7
8		Non-Labor	3,122	3,122	0	8
9		Other	0	0	0	9
10		Total	4,478	4,478	0	10
	520.0	Steam Expenses				
11		Labor	3,673	3,673	0	11
12		Non-Labor	8,771	8,771	0	12
13		Other	0	0	0	13
14		Total	12,444	12,444	0	14
	523.0	Electric Expenses				
15		Labor	616	616	0	15
16		Non-Labor	860	860	0	16
17		Other	0	0	0	17
18		Total	1,476	1,476	0	18
	524.0	Misc Power Expenses				
19		Labor	10,876	10,876	0	19
20		Non-Labor	13,089	13,089	0	20
21		Other	14,320	14,320	0	21
22		Total	38,285	38,285	0	22
	524.0	RD&D				
23		Labor	21	30	9	23
24		Non-Labor	152	223	71	24
25		Other	0	0	0	25
26		Total	173	253	80	26
	525.0	Rents				
27		Other	124	124	0	27
28		Total	124	124	0	28
		Total Operation				
29		Labor	30,354	30,363	9	29
30		Non-Labor	43,340	43,411	71	30
31		Other	15,475	15,475	0	31
32		Total	$89,169	$89,249	$80	32

SOUTHERN CALIFORNIA EDISON COMPANY
Nuclear Production Maintenance Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted (A)	SCE (B)	SCE Exceeds Adopted (C=B-A)	Line No.
	528.0	Supervision & Engineering				
1		Labor	$8,929	$8,929	$0	1
2		Non-Labor	14,269	14,269	0	2
3		Total	23,198	23,198	0	3
	529.0	Maintenance of Structures				
4		Labor	914	914	0	4
5		Non-Labor	2,948	2,948	0	5
6		Total	3,862	3,862	0	6
	530.0	Reactor Plant Equipment				
7		Labor	2,459	2,459	0	7
8		Non-Labor	6,000	6,000	0	8
9		Total	8,459	8,459	0	9
	531.0	Electric Plant				
10		Labor	2,072	2,072	0	10
11		Non-Labor	7,369	7,369	0	11
12		Total	9,441	9,441	0	12
	532.0	Miscellaneous Nuclear Plant				
13		Labor	680	680	0	13
14		Non-Labor	2,850	2,850	0	14
15		Total	3,530	3,530	0	15
		Total Maintenance				
16		Labor	15,054	15,054	0	16
17		Non-Labor	33,436	33,436	0	17
18		Total	$48,490	$48,490	$0	18
		TOTAL NUCLEAR PRODUCTION				
19		Labor	45,408	45,417	9	19
20		Non-Labor	76,776	76,847	71	20
21		Other	15,475	15,475	0	21
22		Total (1982 Dollars)	$137,659	$137,739	$80	22
		Escalation Amounts				
23		Labor	8,164	8,879	715	23
24		Non-Labor	8,161	8,169	8	24
25		Other	0	0	0	25
26		Total	$16,325	$17,048	$723	26
		TOTAL NUCLEAR PRODUCTION				
27		Labor	53,572	54,296	724	27
28		Non-Labor	84,937	85,016	79	28
29		Other	15,475	15,475	0	29
30		Total (1985 Dollars)	$153,984	$154,787	$803	30

APPENDIX B
Page 8

SOUTHERN CALIFORNIA EDISON COMPANY
Hydro Production Expense
Test Year 1985

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted	SCE	SCE Exceeds Adopted Amount	SCE Exceeds Adopted Percent
			(A)	(B)	(C=B-A)	(D=C/A)
		Operation				
1	535.0	Supervision & Engineering	1,494	1,494	0	.0
2	536.0	Water For Power	617	617	0	.0
3	537.0	Hydraulic Expenses	1,160	1,160	0	.0
4	538.0	Electric Expenses	1,658	1,658	0	.0
5	539.0	Misc Hydro Expense Generation	904	904	0	.0
6	539.0	RD&D	42	50	8	19.0%
7	540.0	Rents	163	163	0	.0
8		Total Operation	$6,038	$6,046	$8	.1%
		Maintenance				
9	541.0	Supervision & Engineering	886	886	0	.0
10	542.0	Maintenance of Structures	657	657	0	.0
11	543.0	Maintenance of Reservoirs, Etc.	2,454	2,454	0	.0
12	544.0	Maintenance of Electric Plant	1,925	1,925	0	.0
13	545.0	Maint of Misc Hydro Plant	1,304	1,304	0	.0
14		Total Maintenance	$7,226	$7,226	$0	.0
15		TOTAL HYDRO PRODUCTION	$13,264	$13,272	$8	.1%
		Escalation Amounts				
16		Labor	1,247	1,356	109	8.7%
17		Non-Labor	673	673	0	.0
18		Other	0	0	0	.0
19		Total	$1,920	$2,029	$109	5.7%
20		TOTAL HYDRO (1985 Dollars)	$15,184	$15,301	$117	.8%

SOUTHERN CALIFORNIA EDISON COMPANY
Hydro Production Operation Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted	SCE	SCE Exceeds Adopted	Line No.
			(A)	(B)	(C=B-A)	
	535.0	Supervision & Engineering				
1		Labor	$1,336	$1,336	$0	1
2		Non-Labor	158	158	0	2
3		Other	0	0	0	3
4		Total	1,494	1,494	0	4
	536.0	Water For Power				
5		Labor	3	3	0	5
6		Non-Labor	614	614	0	6
7		Other	0	0	0	7
8		Total	617	617	0	8
	537.0	Hydraulic Expenses				
9		Labor	749	749	0	9
10		Non-Labor	411	411	0	10
11		Other	0	0	0	11
12		Total	1,160	1,160	0	12
	538.0	Electric Expenses				
13		Labor	1,337	1,337	0	13
14		Non-Labor	321	321	0	14
15		Other	0	0	0	15
16		Total	1,658	1,658	0	16
	539.0	Misc Hydro Expense Generation				
17		Labor	592	592	0	17
18		Non-Labor	312	312	0	18
19		Other	0	0	0	19
20		Total	904	904	0	20
	539.0	RD&D				
21		Labor	5	6	1	21
22		Non-Labor	37	44	7	22
23		Other	0	0	0	23
24		Total	42	50	8	24
	540.0	Rents				
25		Labor	0	0	0	25
26		Non-Labor	163	163	0	26
27		Other	0	0	0	27
28		Total	163	163	0	28
		Total Operation				
29		Labor	4,022	4,023	1	29
30		Non-Labor	2,016	2,023	7	30
31		Other	0	0	0	31
32		Total	$6,038	$6,046	$8	32

SOUTHERN CALIFORNIA EDISON COMPANY
Hydro Production Maintenance Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted	SCE	SCE Exceeds Adopted	Line No.
			(A)	(B)	(C=B-A)	
	541.0	Supervision & Engineering				
1		Labor	$623	$623	$0	1
2		Non-Labor	263	263	0	2
3		Total	886	886	0	3
	542.0	Maintenance of Structures				
4		Labor	406	406	0	4
5		Non-Labor	251	251	0	5
6		Total	657	657	0	6
	543.0	Maintenance of Reservoirs, Etc.				
7		Labor	449	449	0	7
8		Non-Labor	2,005	2,005	0	8
9		Total	2,454	2,454	0	9
	544.0	Maintenance of Electric Plant				
10		Labor	1,088	1,088	0	10
11		Non-Labor	837	837	0	11
12		Total	1,925	1,925	0	12
	545.0	Maint of Misc Hydro Plant				
13		Labor	349	349	0	13
14		Non-Labor	955	955	0	14
15		Total	1,304	1,304	0	15
		Total Maintenance				
16		Labor	2,915	2,915	0	16
17		Non-Labor	4,311	4,311	0	17
18		Total	$7,225	$7,225	$0	18
		TOTAL HYDRO PRODUCTION				
19		Labor	6,937	6,938	1	19
20		Non-Labor	6,327	6,334	7	20
21		Other	0	0	0	21
22		Total (1982 Dollars)	$13,264	$13,272	$8	22
		Escalation Amounts				
23		Labor	1,247	1,356	109	23
24		Non-Labor	673	673	0	24
25		Other	0	0	0	25
26		Total	$1,920	$2,029	$109	26
		TOTAL HYDRO PRODUCTION				
27		Labor	8,184	8,294	110	27
28		Non-Labor	7,000	7,007	7	28
29		Other	0	0	0	29
30		Total (1985 Dollars)	$15,184	$15,301	$117	30

APPENDIX B
Page 11

SOUTHERN CALIFORNIA EDISON COMPANY
Other Production Expense
Test Year 1985

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted	SCE	SCE Exceeds Adopted Amount	SCE Exceeds Adopted Percent
			(A)	(B)	(C=B-A)	(D=C/A)
		Operation				
1	546.0	Supervision & Engineering	809	835	26	3.2%
2	548.0	Generation Expenses	2,943	2,943	0	.0
3	549.0	Misc Other Power Expenses	791	947	156	19.7%
4	549.0	RD&D	7,943	8,193	250	3.1%
5	550.0	Rents	18	18	0	.0
6		Total Operation	$12,504	$12,936	$432	3.5%
		Maintenance				
7	551.0	Supervision & Engineering	942	942	0	.0
8	552.0	Maintenance of Structures	460	451	(9)	(2.0%)
9	553.0	Maintenance of Electric Plant	7,751	7,751	0	.0
10	554.0	Misc Other Power Generation Plant	1,248	1,301	53	4.2%
11		Total Maintenance	$10,401	$10,445	$44	.4%
12		TOTAL OTHER PRODUCTION	$22,905	$23,381	$476	2.1%
		Escalation Amounts				
13		Labor	1,037	1,134	97	9.4%
14		Non-Labor	1,455	1,501	46	3.2%
15		Other	0	0	0	.0
16		Total	$2,492	$2,635	$143	5.7%
17		TOTAL OTHER (1985 Dollars)	$25,397	$26,016	$619	2.4%

SOUTHERN CALIFORNIA EDISON COMPANY
Other Production Operation Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted	SCE	SCE Exceeds Adopted	Line No.
			(A)	(B)	(C=B-A)	
	546.0	Supervision & Engineering				
1		Labor	$753	$753	$0	1
2		Non-Labor	56	82	26	2
3		Other	0	0	0	3
4		Total	809	835	26	4
	548.0	Generation Expenses				
5		Labor	1,637	1,637	0	5
6		Non-Labor	1,306	1,306	0	6
7		Other	0	0	0	7
8		Total	2,943	2,943	0	8
	549.0	Misc Other Power Expenses				
9		Labor	373	373	0	9
10		Non-Labor	418	574	156	10
11		Other	0	0	0	11
12		Total	791	947	156	12
	549.0	RD&D				
13		Labor	517	555	38	13
14		Non-Labor	3,988	4,200	212	14
15		Other (Fuel Cell Writeoff)	3,438	3,438	0	15
16		Total	7,943	8,193	250	16
	550.0	Rents				
17		Labor	0	0	0	17
18		Non-Labor	0	0	0	18
19		Other	18	18	0	19
20		Total	18	18	0	20
		Total Operation				
21		Labor	3,280	3,318	38	21
22		Non-Labor	5,768	6,162	394	22
23		Other	3,456	3,456	0	23
24		Total	$12,504	$12,936	$432	24

SOUTHERN CALIFORNIA EDISON COMPANY
Other Production Maintenance Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted	SCE	SCE Exceeds Adopted	Line No.
			(A)	(B)	(C=B-A)	
	551.0	Supervision & Engineering				
1		Labor	$776	$776	$0	1
2		Non-Labor	166	166	0	2
3		Total	942	942	0	3
	552.0	Maintenance of Structures				
4		Labor	148	148	0	4
5		Non-Labor	312	303	(9)	5
6		Total	460	451	(9)	6
	553.0	Maintenance of Electric Plant				
7		Labor	1,488	1,488	0	7
8		Non-Labor	6,263	6,263	0	8
9		Total	7,751	7,751	0	9
	554.0	Misc Other Power Generation Plant				
10		Labor	73	73	0	10
11		Non-Labor	1,175	1,228	53	11
12		Total	1,248	1,301	53	12
		Total Maintenance				
13		Labor	2,485	2,485	0	13
14		Non-Labor	7,916	7,960	44	14
15		Total	$10,401	$10,445	$44	15
		TOTAL OTHER PRODUCTION				
16		Labor	5,765	5,803	38	16
17		Non-Labor	13,684	14,122	438	17
18		Other	3,456	3,456	0	18
19		Total (1982 Dollars)	$22,905	$23,381	$476	19
		Escalation Amounts				
20		Labor	1,037	1,134	97	20
21		Non-Labor	1,455	1,501	46	21
22		Other	0	0	0	22
23		Total	$2,492	$2,635	$143	23
		TOTAL OTHER PRODUCTION				
24		Labor	6,802	6,937	135	24
25		Non-Labor	15,139	15,623	484	25
26		Other	3,456	3,456	0	26
27		Total (1985 Dollars)	$25,397	$26,016	$619	27

SOUTHERN CALIFORNIA EDISON COMPANY
Transmission Operation Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted (A)	SCE (B)	SCE Exceeds Adopted (C=B-A)	Line No.
	560.0	Supervision & Engineering				
1		Labor	$2,923	$2,923	$0	1
2		Non-Labor	774	774	0	2
3		Other	0	0	0	3
4		Total	3,697	3,697	0	4
	561.0	Load Dispatching				
5		Labor	2,338	2,338	0	5
6		Non-Labor	(34)	(34)	0	6
7		Other	0	0	0	7
8		Total	2,304	2,304	0	8
	562.0	Station Expenses				
9		Labor	10,605	10,605	0	9
10		Non-Labor	1,851	1,851	0	10
11		Other	0	0	0	11
12		Total	12,456	12,456	0	12
	563.0	Overhead Line Expenses				
13		Labor	552	552	0	13
14		Non-Labor	331	331	0	14
15		Other	0	0	0	15
16		Total	883	883	0	16
	564.0	Underground Line Expenses				
17		Labor	19	19	0	17
18		Non-Labor	10	10	0	18
19		Other	0	0	0	19
20		Total	29	29	0	20
	565.0	Trans of Electricity By Others				
21		Labor	0	0	0	21
22		Non-Labor	0	0	0	22
23		Other	13,883	13,883	0	23
24		Total	13,883	13,883	0	24
	566.0	Misc Transmission Expenses				
25		Labor	1,038	1,038	0	25
26		Non-Labor	633	633	0	26
27		Other	0	0	0	27
28		Total	1,671	1,671	0	28

SOUTHERN CALIFORNIA EDISON COMPANY
Transmission Operation Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted	SCE	SCE Exceeds Adopted	Line No.
			(A)	(B)	(C=B-A)	
	566.0	RD&D				
1		Labor	59	84	25	1
2		Non-Labor	441	628	187	2
3		Other	0	0	0	3
4		Total	500	712	212	4
	567.0	Rents				
5		Labor	0	0	0	5
6		Non-Labor	516	516	0	6
7		Other	1,054	1,054	0	7
8		Total	1,570	1,570	0	8
		Total Operation				
9		Labor	17,534	17,559	25	9
10		Non-Labor	4,522	4,709	187	10
11		Other	14,937	14,937	0	11
12		Total	$36,993	$37,205	$212	12

SOUTHERN CALIFORNIA EDISON COMPANY
Transmission Maintenance Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted (A)	SCE (B)	SCE Exceeds Adopted (C=B-A)	Line No.
	568.0	Supervision & Engineering				
1		Labor	$2,462	$2,462	$0	1
2		Non-Labor	542	542	0	2
3		Other	0	0	0	3
4		Total	3,004	3,004	0	4
	569.0	Maintenance of Structures				
5		Labor	263	263	0	5
6		Non-Labor	734	734	0	6
7		Other	0	0	0	7
8		Total	997	997	0	8
	570.0	Maintenance of Station Equipment				
9		Labor	3,445	3,445	0	9
10		Non-Labor	4,778	4,778	0	10
11		Other	0	0	0	11
12		Total	8,223	8,223	0	12
	571.0	Maintenance of Overhead Lines				
13		Labor	2,808	3,188	380	13
14		Non-Labor	6,982	6,982	0	14
15		Other	0	0	0	15
16		Total	9,790	10,170	380	16
	572.0	Maintenance of Underground Lines				
17		Labor	43	43	0	17
18		Non-Labor	81	81	0	18
19		Other	0	0	0	19
20		Total	124	124	0	20
	573.0	Maintenance of Misc Trans Plant				
21		Labor	346	346	0	21
22		Non-Labor	2,907	2,907	0	22
23		Other	0	0	0	23
24		Total	3,253	3,253	0	24
		Total Maintenance				
25		Labor	9,367	9,747	380	25
26		Non-Labor	16,024	16,024	0	26
27		Other	0	0	0	27
28		Total	$25,391	$25,771	$380	28

SOUTHERN CALIFORNIA EDISON COMPANY
Transmission Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	Adopted (A)	SCE (B)	SCE Exceeds Adopted (C=B-A)	Line No.
		TOTAL TRANSMISSION				
1		Labor	25,901	27,306	405	1
2		Non-Labor	20,546	20,733	187	2
3		Other	14,937	14,937	0	3
4		Total (1982 Dollars)	$62,384	$62,976	$592	4
		Escalation Amounts				
5		Labor	4,837	5,338	501	5
6		Non-Labor	2,184	2,204	20	6
7		Other	0	0	0	7
8		Total	$7,021	$7,542	$521	8
		TOTAL TRANSMISSION				
9		Labor	31,738	32,644	906	9
10		Non-Labor	22,730	22,937	207	10
11		Other	14,937	14,937	0	11
12		Total (1985 Dollars)	$69,405	$70,518	$1,113	12

SOUTHERN CALIFORNIA EDISON COMPANY
Distribution Operation Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
	580.0	Supervision & Engineering				
1		Labor	$10,597	$11,722	$1,125	1
2		Non-Labor	1,054	867	(187)	2
3		Other	0	0	0	3
4		Total	11,651	12,589	938	4
	582.0	Station Expenses				
5		Labor	6,941	6,941	0	5
6		Non-Labor	917	917	0	6
7		Other	0	0	0	7
8		Total	7,858	7,858	0	8
	583.0	Overhead Line Expenses				
9		Labor	2,983	3,984	1,001	9
10		Non-Labor	2,665	2,665	0	10
11		Other	0	0	0	11
12		Total	5,648	6,649	1,001	12
	584.0	Underground Line Expenses				
13		Labor	939	996	57	13
14		Non-Labor	431	431	0	14
15		Other	0	0	0	15
16		Total	1,370	1,427	57	16
	585.0	Street Lighting and Signals				
17		Labor	106	106	0	17
18		Non-Labor	1,445	1,445	0	18
19		Other	0	0	0	19
20		Total	1,551	1,551	0	20
	586.0	Meter Expenses				
21		Labor	9,684	10,964	1,280	21
22		Non-Labor	(404)	(404)	0	22
23		Other	0	0	0	23
24		Total	9,280	10,560	1,280	24
	587.0	Customer Installations				
25		Labor	7,333	7,333	0	25
26		Non-Labor	2,573	2,573	0	26
27		Other	0	0	0	27
28		Total	9,906	9,906	0	28

SOUTHERN CALIFORNIA EDISON COMPANY
Distribution Operation Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
	588.0	Misc Distribution Expenses				
1		Labor	$5,851	$5,851	$0	1
2		Non-Labor	2,672	2,672	0	2
3		Other	0	0	0	3
4		Total	8,523	8,523	0	4
	588.0	ROAD				
5		Labor	0	6	6	5
6		Non-Labor	0	44	44	6
7		Other	0	0	0	7
8		Total	0	50	50	8
	589.0	Rents				
9		Labor	0	0	0	9
10		Non-Labor	598	500	(98)	10
11		Other	0	0	0	11
12		Total	598	500	(98)	12
		Total Operation				
13		Labor	44,436	47,905	3,469	13
14		Non-Labor	11,949	11,708	(241)	14
15		Other	0	0	0	15
16		Total	$56,385	$59,613	$3,228	16

SOUTHERN CALIFORNIA EDISON COMPANY
Distribution Maintenance Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
	590.0	Supervision & Engineering				
1		Labor	$7,493	$8,154	$661	1
2		Non-Labor	1,394	1,224	(170)	2
3		Other	0	0	0	3
4		Total	8,887	9,378	491	4
	591.0	Maintenance of Structures				
5		Labor	210	210	0	5
6		Non-Labor	2,827	2,827	0	6
7		Other	0	0	0	7
8		Total	3,037	3,037	0	8
	592.0	Maintenance of Station Equipment				
9		Labor	2,917	3,024	107	9
10		Non-Labor	2,362	2,752	390	10
11		Other	0	0	0	11
12		Total	5,279	5,776	497	12
	593.0	Maintenance of Overhead Lines				
13		Labor	8,912	10,829	1,917	13
14		Non-Labor	9,860	9,860	0	14
15		Other	0	0	0	15
16		Total	18,772	20,689	1,917	16
	594.0	Maintenance of Underground Lines				
17		Labor	2,736	3,594	858	17
18		Non-Labor	2,684	2,724	40	18
19		Other	0	0	0	19
20		Total	5,420	6,318	898	20
	595.0	Maintenance of Line Transformers				
21		Labor	1,547	1,547	0	21
22		Non-Labor	3,012	3,012	0	22
23		Other	0	0	0	23
24		Total	4,559	4,559	0	24
	596.0	Maint of Street Lighting & Signals				
25		Labor	965	965	0	25
26		Non-Labor	876	876	0	26
27		Other	0	0	0	27
28		Total	1,841	1,841	0	28

SOUTHERN CALIFORNIA EDISON COMPANY
Distribution Maintenance Expense
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
	597.0	Maintenance of Meters				
1		Labor	$974	$974	$0	1
2		Non-Labor	499	499	0	2
3		Other	0	0	0	3
4		Total	1,473	1,473	0	4
	598.0	Maint of Misc Distribution Plant				
5		Labor	29	32	3	5
6		Non-Labor	14,965	15,604	639	6
7		Other	0	0	0	7
8		Total	14,994	15,636	642	8
		Total Maintenance				
9		Labor	25,783	29,329	3,546	9
10		Non-Labor	38,479	39,378	899	10
11		Other	0	0	0	
12		Total	$64,262	$68,707	$4,445	12
		TOTAL DISTRIBUTION				
13		Labor	70,219	77,224	7,015	13
14		Non-Labor	50,428	51,086	658	14
15		Other	0	0	0	15
16		Total (1982 Dollars)	$120,647	$128,320	$7,673	16
		Escalation Amounts				
17		Labor	12,625	15,099	2,474	17
18		Non-Labor	5,360	5,430	70	18
19		Other	0	0	0	19
20		Total	$17,985	$20,529	$2,544	20
		TOTAL DISTRIBUTION				
21		Labor	82,844	92,333	9,489	21
22		Non-Labor	55,788	56,516	728	22
23		Other	0	0	0	23
24		Total (1985 Dollars)	$138,632	$148,849	$10,217	24

Appendix B
Page 22
SOUTHERN CALIFORNIA EDISON COMPANY
Customer Accounts Expenses
Test Year 1985

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED	SCE	SCE Excess ADO Amount	SCE Excess ADO Percent
			(A)	(B)	(C=B-A)	(D=C/A)
1	901.0	Supervision	4,610	4,610	0	.0
2	902.0	Meter Reading Expenses	16,622	17,133	511	3.1%
3	903.0	Customer Records & Collections	45,785	45,330	(455)	(1.0%)
4	904.0	Uncollectible Accounts	5,732	5,707	(25)	(.4%)
5	905.0	Misc Customer Accounts Expense	2,530	2,530	0	.0
6		TOTAL CUSTOMER ACCOUNTS	$73,279	$73,310	$31	.0
7		TOTAL (Less Uncollectibles)	$69,547	$69,603	$56	.1%
		Escalation Amounts				
8		Labor	8,152	8,953	801	9.8%
9		Non-Labor	1,645	1,651	6	.4%
10		Other	0	0	0	.0
11		Total	$9,797	$10,604	$807	8.2%
12		TOTAL (1985 Dollars)	$83,076	$83,914	$838	1.0%
13		TOTAL (Less Uncollectibles)	$79,344	$80,207	$863	1.1%

SOUTHERN CALIFORNIA EDISON COMPANY
Customer Accounts Expenses
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
	901.0	Supervision				
1		Labor	$3,278	$3,278	$0	1
2		Non-Labor	1,332	1,332	0	2
3		Other	0	0	0	3
4		Total	4,610	4,610	0	4
	902.0	Meter Reading Expenses				
5		Labor	14,126	14,579	453	5
6		Non-Labor	2,496	2,554	58	6
7		Other	0	0	0	7
8		Total	16,622	17,133	511	8
	903.0	Customer Records & Collections				
9		Labor	26,534	26,534	0	9
10		Non-Labor	10,518	10,518	0	10
11		Other (Postage)	8,733	8,278	(455)	11
12		Total	45,785	45,330	(455)	12
	904.0	Uncollectible Accounts				
13		Labor	0	0	0	13
14		Non-Labor	0	0	0	14
15		Other	5,732	5,707	(25)	15
16		Total	5,732	5,707	(25)	16
	905.0	Misc Customer Accounts Expense				
17		Labor	1,404	1,404	0	17
18		Non-Labor	1,126	1,126	0	18
19		Other	0	0	0	19
20		Total	2,530	2,530	0	20
		TOTAL CUSTOMER ACCOUNTS				
21		Labor	45,342	45,795	453	21
22		Non-Labor	15,472	15,530	58	22
23		Other	14,465	13,985	(480)	23
24		Total (1982 Dollars)	$75,279	$75,310	$31	24
		Escalation Amounts				
25		Labor	8,152	8,953	801	25
26		Non-Labor	1,645	1,651	6	26
27		Other	0	0	0	27
28		Total	$9,797	$10,604	$807	28
		TOTAL CUSTOMER ACCOUNTS				
29		Labor	53,494	54,748	1,254	29
30		Non-Labor	17,117	17,181	64	30
31		Other	14,465	13,985	(480)	31
32		Total (1985 Dollars)	$85,076	$85,914	$838	32

Appendix B
Page 24
SOUTHERN CALIFORNIA EDISON COMPANY
Customer Service and Informational Expenses
Test Year 1985

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exc Amount (C=B-A)	SCE Exc Percent (D=C/A)
		Conservation				
1	907.0	Supervision	1,358	1,621	263	19.4%
2	908.0	Customer Assistance Expense	30,481	37,233	6,752	22.2%
3	909.0	Informational & Instructional Exp	2,116	2,476	360	17.0%
4		Total Conservation	$33,955	$41,330	$7,375	21.7%
		Load Management				
5	907.0	Supervision	269	305	36	13.4%
6	908.0	Customer Assistance Expense	8,541	11,717	3,176	37.2%
7	909.0	Informational & Instructional Exp	1,435	1,704	269	18.7%
8		Total Load Management	$10,245	$13,726	$3,481	34.0%
9		TOTAL CUSTOMER SERVICE & INFO	$44,200	$55,056	$10,856	24.6%
		Escalation Amounts				
10		Labor	3,516	4,580	1,064	30.3%
11		Non-Labor	1,721	1,956	235	13.7%
12		Other	0	0	0	.0
13		Total	$5,237	$6,536	$1,299	24.8%
14		TOTAL (1985 Dollars)	$49,437	$61,592	$12,155	24.6%

Appendix B
Page 25

SOUTHERN CALIFORNIA EDISON COMPANY
Customer Service and Informational Expenses
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
		Conservation				
	907.0	Supervision				
1		Labor	$1,061	$1,275	$214	1
2		Non-Labor	297	346	49	2
3		Other	0	0	0	3
4		Total	1,358	1,621	263	4
	908.0	Customer Assistance Expense				
5		Labor	14,272	17,168	2,896	5
6		Non-Labor	8,294	9,630	1,336	6
7		Other	7,915	10,415	2,500	7
8		Total	30,481	37,223	6,732	8
	909.0	Informational & Instructional Expense				
9		Labor	221	387	66	9
10		Non-Labor	1,795	2,089	294	10
11		Other	0	0	0	11
12		Total	2,116	2,476	360	12
		Total Conservation				
13		Labor	15,554	18,830	3,176	13
14		Non-Labor	10,386	12,085	1,699	14
15		Other	7,915	10,415	2,500	15
16		Total	33,955	41,330	7,375	16

SOUTHERN CALIFORNIA EDISON COMPANY
Customer Service and Informational Expenses
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
		Load Management				
	907.0	Supervision				
1		Labor	$212	$238	$26	1
2		Non-Labor	57	67	10	2
3		Other	0	0	0	3
4		Total	269	305	36	4
	908.0	Customer Assistance Expense				
5		Labor	3,653	4,322	669	5
6		Non-Labor	4,348	4,580	232	6
7		Other	540	2,815	2,275	7
8		Total	8,541	11,717	3,176	8
	909.0	Informational & Instructional Expense				
9		Labor	37	37	0	9
10		Non-Labor	1,398	1,667	269	10
11		Other	0	0	0	11
12		Total	1,435	1,704	269	12
		Total Load Management				
13		Labor	3,902	4,597	695	13
14		Non-Labor	5,803	6,314	511	14
15		Other	540	2,815	2,275	15
16		Total	10,245	13,726	3,481	16
		TOTAL CUSTOMER SERVICE & INFORMATION				
17		Labor	19,536	23,427	3,871	17
18		Non-Labor	16,189	18,399	2,210	18
19		Other	8,455	13,230	4,775	19
20		Total (1982 Dollars)	$44,200	$55,056	$10,856	20
		Escalation Amounts				
21		Labor	3,516	4,580	1,064	21
22		Non-Labor	1,721	1,956	235	22
23		Other	0	0	0	23
24		Total	$5,237	$6,536	$1,299	24
		TOTAL CUSTOMER SERVICE & INFORMATION				
25		Labor	23,072	28,007	4,935	25
26		Non-Labor	17,910	20,355	2,445	26
27		Other	8,455	13,230	4,775	27
28		Total (1985 Dollars)	$49,437	$61,592	$12,155	28

Appendix B
Page 27
SOUTHERN CALIFORNIA EDISON COMPANY
Administrative and General Expenses
Test Year 1985

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED	SCE	SCE Exceeds ADO Amount	SCE Exceeds ADO Percent
			(A)	(B)	(C=B-A)	(D=C/A)
		Operation				
1	920.0	Administrative & General Salaries	80,778	83,346	2,568	3.2%
2	921.0	Office Supplies and Expenses	21,375	22,969	1,594	7.5%
3	922.0	Admin & General Transfer Credit	(20,635)	(21,476)	(841)	4.1%
4	922.0	Outside Services Employed	4,322	6,103	1,781	40.9%
5	924.0	Property Insurance	15,373	15,811	438	2.8%
6	925.0	Injuries and Damages	13,760	13,760	0	.0
7	926.0	Employee Pensions & Benefits	96,610	103,162	6,552	6.8%
8	927.0	Franchise Requirements	20,290	20,201	(89)	(.4%)
9	928.0	Regulatory Commission Expenses	3,277	3,277	0	.0
10	929.0	Duplicate Charges - Credit	0	0	0	.0
11	930.1	Misc Advertising Expenses	245	245	0	.0
12	930.2	Miscellaneous General Expenses	5,181	6,302	1,121	21.6%
13	930.2	RD&D	17,913	18,411	498	2.8%
14	931.0	Rents	2,636	2,901	265	10.1%
15		Total Operation	$261,135	$275,012	$13,877	5.3%
		Maintenance				
16	932.0	Maintenance of General Plant	9,404	9,404	0	.0
17		Total Maintenance	$9,404	$9,404	$0	.0
18		TOTAL ADMINISTRATIVE & GENERAL	$270,539	$284,416	$13,877	5.1%
19		TOTAL (Less Account 927)	$250,249	$264,215	$13,966	5.6%
		Escalation Amounts				
20		Labor	12,842	14,427	1,585	12.3%
21		Non-Labor	5,824	6,313	489	8.4%
22		Other	0	0	0	.0
23		Total	$18,666	$20,740	$2,074	11.1%
24		TOTAL A&G (1985 Dollars)	$289,205	$305,156	$15,951	5.5%
25		TOTAL (Less Account 927)	$268,915	$284,955	$16,040	6.0%

SOUTHERN CALIFORNIA EDISON COMPANY
Administrative and General Expenses
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
	920.0	Administrative & General Salaries				
1		Labor	$80,778	$83,346	$2,568	1
2		Non-Labor	0	0	0	2
3		Other	0	0	0	3
4		Total	80,778	83,346	2,568	4
	921.0	Office Supplies and Expenses				
5		Labor	0	0	0	5
6		Non-Labor	21,375	22,969	1,594	6
7		Other	0	0	0	7
8		Total	21,375	22,969	1,594	8
	922.0	Admin & General Transfer Credit				
9		Labor	(16,317)	(16,836)	(519)	9
10		Non-Labor	(4,318)	(4,640)	(322)	10
11		Other	0	0	0	11
12		Total	(20,635)	(21,476)	(841)	12
	923.0	Outside Services Employed				
13		Labor	0	0	0	13
14		Non-Labor	4,332	6,103	1,771	14
15		Other	0	0	0	15
16		Total	4,332	6,103	1,771	16
	924.0	Property Insurance				
17		Labor	12	12	0	17
18		Non-Labor	2,400	2,400	0	18
19		Other	12,961	13,399	438	19
20		Total	15,373	15,811	438	20
	925.0	Injuries and Damages				
21		Labor	1,028	1,028	0	21
22		Non-Labor	10,696	10,696	0	22
23		Other	2,036	2,036	0	23
24		Total	13,760	13,760	0	24
	926.0	Employee Pensions & Benefits				
25		Labor	2,817	2,986	169	25
26		Non-Labor	1,613	1,613	0	26
27		Other	92,180	98,563	6,383	27
28		Total	96,610	103,162	6,552	28
	927.0	Franchise Requirements				
29		Labor	0	0	0	29
30		Non-Labor	0	0	0	30
31		Other	20,290	20,201	(89)	31
32		Total	20,290	20,201	(89)	32

SOUTHERN CALIFORNIA EDISON COMPANY
Administrative and General Expenses
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
	928.0	Regulatory Commission Expenses				
1		Labor	$436	$436	$0	1
2		Non-Labor	2,841	2,841	0	2
3		Other	0	0	0	3
4		Total	3,277	3,277	0	4
	929.0	Duplicate Charges - Credit				
5		Labor	0	0	0	5
6		Non-Labor	0	0	0	6
7		Other	0	0	0	7
8		Total	0	0	0	8
	930.1	Misc Advertising Expenses				
9		Labor	111	111	0	9
10		Non-Labor	134	134	0	10
11		Other	0	0	0	11
12		Total	245	245	0	12
	930.2	Miscellaneous General Expenses				
13		Labor	(2,574)	(2,478)	96	13
14		Non-Labor	5,906	6,931	1,025	14
15		Other	1,849	1,849	0	15
16		Total	5,181	6,302	1,121	16
	930.2	RD&D				
17		Labor	1,108	1,165	57	17
18		Non-Labor	3,884	4,335	451	18
19		Other (Dues)	12,921	12,911	(10)	19
20		Total	17,913	18,411	498	20
	931.0	Rents				
21		Labor	0	0	0	21
22		Non-Labor	549	627	78	22
23		Other	2,087	2,274	187	23
24		Total	2,636	2,901	265	24
		Total Operation				
25		Labor	67,399	69,770	2,371	25
26		Non-Labor	49,412	54,009	4,597	26
27		Other	144,324	151,233	6,909	27
28		Total	$261,135	$275,012	$13,877	28

SOUTHERN CALIFORNIA EDISON COMPANY
Administrative and General Expenses
Test Year 1985

Expense By Labor, Non-Labor, and Other

(Thousands Of Dollars)

Line No.	Account No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPTED (C=B-A)	Line No.
	932.0	Maintenance of General Plant				
1		Labor	$4,024	$4,024	$0	1
2		Non-Labor	5,380	5,380	0	2
3		Total	9,404	9,404	0	3
		Total Maintenance				
4		Labor	4,024	4,024	0	4
5		Non-Labor	5,380	5,380	0	5
6		Total	$9,404	$9,404	$0	6
		TOTAL ADMINISTRATIVE AND GENERAL				
7		Labor	71,423	73,794	2,371	7
8		Non-Labor	54,792	59,389	4,597	8
9		Other	144,324	151,233	6,909	9
10		Total (1982 Dollars)	$270,539	$284,416	$13,877	10
		Escalation Amounts				
11		Labor	12,842	14,427	1,585	11
12		Non-Labor	5,824	6,313	489	12
13		Other	0	0	0	13
14		Total	$18,666	$20,740	$2,074	14
		TOTAL ADMINISTRATIVE AND GENERAL				
15		Labor	84,265	88,221	3,956	15
16		Non-Labor	60,616	65,702	5,086	16
17		Other	144,324	151,233	6,909	17
18		Total (1985 Dollars)	$289,205	$305,156	$15,951	18

Appendix B
Page 31
SOUTHERN CALIFORNIA EDISON COMPANY
Taxes Other Than On Income
(Including Songs Unit 1)
Test Year 1985

(Thousands Of Dollars)

Line No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOP Amount (C=B-A)	SCE Exceeds ADOP Percent (D=C/A)
	Ad Valorem Taxes				
1	California	$55,750	$55,750	0	.0
2	Arizona	1,356	1,356	0	.0
3	New Mexico	636	636	0	.0
4	Nevada	928	928	0	.0
5	Total Ad Valorem Taxes	$58,670	$58,670	$0	.0
	Payroll Taxes				
6	Social Security Tax Act	26,387	28,473	2,086	7.9%
7	Federal Unemployment Tax Act	638	667	29	4.5%
8	State Unemployment Insurance Act	1,142	1,257	115	10.1%
9	Total Payroll Taxes	$28,167	$30,397	$2,230	7.9%
	Miscellaneous Taxes				
10	Federal	(225)	(225)	0	.0
11	State	(15)	(15)	0	.0
12	Local	(50)	(50)	0	.0
13	Federal, State & Local Transferred	190	190	0	.0
14	Total Miscellaneous Taxes	($100)	($100)	$0	.0
15	Total Taxes Other Than On Income	$86,737	$88,967	$2,230	2.6%

Appendix B
Page 32

SOUTHERN CALIFORNIA EDISON COMPANY
Income Tax Adjustments
(Including Songs Unit 1)
Test Year 1985

(Thousands Of Dollars)

Line No.	Description	ADOPTED	SCE	SCE Exceeds ADOPT Amount	SCE Exceeds ADOPT Percent
		(A)	(B)	(C=B-A)	(D=C/A)
	California Income Tax Adjustments				
1	Tax Depreciation	276,625	276,625	0	.0
2	Fuel Oil Pipeline	(4,516)	(4,516)	0	.0
3	Nuclear Fuel Amortization	(8,618)	(8,618)	0	.0
4	Interest Charges	238,889	241,290	2,401	1.0%
5	Nuclear Fuel Lease Interest	6,980	6,980	0	.0
6	Benefits Capitalized	41,909	45,889	3,980	9.5%
7	Payroll Taxes Capitalized	10,979	11,558	579	5.3%
8	Ad Valorem Taxes Capitalized	6,030	6,030	0	.0
9	Use Tax Capitalized	4,108	4,108	0	.0
10	Ad Valorem Lien Date Adjustment	2,625	2,625	0	.0
11	Removal Costs	15,531	15,531	0	.0
12	Right of Way Easement Amortization	1,075	1,075	0	.0
13	Repair Allowance	13,000	13,000	0	.0
14	Salvage Warehouse Expense	316	316	0	.0
15	Plutonium Amortization	0	0	0	.0
16	Sleeving Amortization	0	0	0	.0
17	Esop	4,161	4,161	0	.0
18	Total CCFT Adjustments	$609,095	$616,055	$6,960	1.1%
	Federal Income Tax Adjustments				
19	Tax Depreciation	226,470	226,470	0	.0
20	Fuel Oil Pipeline	(4,516)	(4,516)	0	.0
21	Nuclear Fuel Amortization	(8,618)	(8,618)	0	.0
22	Interest Charges	238,889	241,290	2,401	1.0%
23	Nuclear Fuel Lease Interest	6,980	6,980	0	.0
24	Benefits Capitalized	41,909	45,889	3,980	9.5%
25	Payroll Taxes Capitalized	10,979	11,558	579	5.3%
26	Ad Valorem Taxes Capitalized	6,030	6,030	0	.0
27	Use Tax Capitalized	4,108	4,108	0	.0
28	Ad Valorem Lien Date Adjustment	2,625	2,625	0	.0
29	Removal Costs	15,531	15,531	0	.0
30	Right of Way Easement Amortization	1,075	1,075	0	.0
31	Repair Allowance	13,000	13,000	0	.0
32	Salvage Warehouse Expense	316	316	0	.0
33	Plutonium Amortization	0	0	0	.0
34	Sleeving Amortization	0	0	0	.0
35	Preferred Dividend Credit	615	615	0	.0
36	Total FIT Adjustments	$555,393	$562,353	$6,960	1.3%

Appendix B
Page 33

SOUTHERN CALIFORNIA EDISON COMPANY
Taxes On Income - Present Rates
(Including Songs Unit 1)
Test Year 1985

(Thousands Of Dollars)

Line No.	Description	ADOPTED	SCE	SCE Excess ADOPT Amount	SCE Excess ADOPT Percent
		(A)	(B)	(C=B-A)	(D=C/A)
	California Corporation Franchise Tax				
1	Operating Revenues	$2,705,134	$2,694,009	($11,125)	(.4%)
2	Operating Expenses	1,023,551	1,080,837	57,286	5.6%
3	Taxes Other Than On Income	86,737	88,967	2,230	2.6%
4	Subtotal	$1,110,288	$1,169,804	$59,516	5.4%
5	Income Tax Adjustments	609,095	616,055	6,960	1.1%
6	California Taxable Income	$985,751	$908,150	($77,601)	(7.9%)
7	CCFT Tax Rate	.09295	.09295		
8	California Corporation Franchise Tax	$91,626	$84,413	($7,213)	(7.9%)
9	Arizona Income Tax	69	64	(5)	(7.2%)
10	New Mexico Income Tax	177	163	(14)	(7.9%)
11	Total CCFT	$91,872	$84,640	($7,232)	(7.9%)
	Federal Income Tax				
12	Operating Revenues	$2,705,134	$2,694,009	($11,125)	(.4%)
13	Operating Expenses	1,023,551	1,080,837	57,286	5.6%
14	Taxes Other Than On Income	86,737	88,967	2,230	2.6%
15	State Income Taxes	91,872	84,640	(7,232)	(7.9%)
16	Subtotal	$1,202,160	$1,254,444	$52,284	4.3%
17	Income Tax Adjustments	333,393	362,353	6,960	1.3%
18	Federal Taxable Income	$947,581	$877,212	($70,369)	(7.4%)
19	FIT Tax Rate	.46	.46		
20	Federal Income Tax	$435,887	$403,518	($32,370)	(7.4%)
21	Graduated Rate Benefit	0	0	0	ERROR
22	Research & Experimental Credit	(1,582)	(1,908)	(326)	20.6%
23	Investment Tax Credit Normalized	(9,882)	(9,882)	0	.0
24	Defense Facilities Credit	(1,872)	(1,872)	0	.0
25	Total Federal Income Tax	$422,551	$389,856	($32,696)	(7.7%)

SOUTHERN CALIFORNIA EDISON COMPANY
Electric Plant In Service
(Including Songs Unit 1)
Test Year 1985

(Thousands Of Dollars)

Line No.	Description	ADOPTED	SCE	SCE Exceeds Adopted Amount	Percent
		(A)	(B)	(C=B-A)	(D=C/A)
	Beginning of Year Plant				
1	Intangible	113	113	0	.0
2	Production				
3	Steam	1,609,533	1,609,533	0	.0
4	Nuclear	366,719	366,719	0	.0
5	Hydraulic	256,070	256,070	0	.0
6	Other	432,990	432,990	0	.0
7	Total Production	2,665,312	2,665,312	0	.0
8	Transmission	1,528,141	1,528,141	0	.0
9	Distribution	3,004,135	3,004,135	0	.0
10	General	329,863	329,863	0	.0
11	Common	93	93	0	.0
12	Total Beginning of Year Plant	7,527,717	7,527,717	0	.0
13	Weighted Average Net Additions	383,127	383,127	0	.0
14	Total Weighted Average Plant	$7,910,844	$7,910,844	$0	.0
	Load Management				
15	Plant in Service - BOY	10,533	10,533	0	.0
16	Weighted Average Additions	3,590	3,590	0	.0
17	Total Load Management	14,123	14,123	0	.0
18	Total Weighted Average Plant	$7,924,967	$7,924,967	$0	.0

SOUTHERN CALIFORNIA EDISON COMPANY
Depreciation Expense
(Including Songs Unit 1)
Test Year 1985

(Thousands Of Dollars)

Line No.	Description	ADOPTED	SCE	SCE Excess Adopted Amount	Percent
		(A)	(B)	(C=B-A)	(D=C/A)
	Production				
1	Steam	65,710	65,710	0	.0
2	Nuclear	13,267	13,267	0	.0
3	Hydro	3,575	3,575	0	.0
4	Other	16,235	16,235	0	.0
5	Total Production	98,787	98,787	0	.0
	Transmission				
6	Substations	13,944	13,944	0	.0
7	Lines	30,006	30,006	0	.0
8	Total Transmission	43,950	43,950	0	.0
	Distribution				
9	Substations	15,265	15,265	0	.0
10	Lines	139,262	139,262	0	.0
11	Total Distribution	154,527	154,527	0	.0
12	General	13,683	13,683	0	.0
13	Load Management Program	490	490	0	.0
14	Common	3	3	0	.0
15	Experimental Plant	14,462	14,462	0	.0
16	Nuclear Decommissioning (Songs 1)	3,760	3,760	0	.0
17	Total Depreciation Expense	$329,662	$329,662	$0	.0
	Charged to Other				
18	Other Depreciable	715	715	0	.0
19	Fuel Oil Transportation Facility	4,516	4,516	0	.0
20	Total Charged to Other	$5,231	$5,231	$0	.0

SOUTHERN CALIFORNIA EDISON COMPANY
Depreciation Reserve
(Including Songs Unit 1)
Test Year 1985

(Thousands Of Dollars)

Line No.	Description	ADOPTED	SCE	SCE Exceeds Adopted Amount	SCE Exceeds Adopted Percent
		(A)	(B)	(C=B-A)	(D=C/A)
1	Beginning of Year Reserve	2,668,909	2,668,909	0	.0
2	Depreciation Accrual	334,893	334,893	0	.0
3	Net Retirements	(41,174)	(41,174)	0	.0
4	Retirement Work in Progress	(5,100)	(5,100)	0	.0
5	End of Year Reserve	$2,957,528	$2,957,528	$0	.0
6	Total Weighted Average Reserve	2,810,658	2,810,658	0	.0
7	Less Load Management Reserve	277	277	0	.0
8	Total Weighted Average Reserve	$2,810,381	$2,810,381	$0	.0

Appendix B
Page 37

SOUTHERN CALIFORNIA EDISON COMPANY
Weighted Average Depreciated Rate Base
(Including Songs Unit 1)
Test Year 1985

(Thousands Of Dollars)

Line No.	Description	ADOPTED (A)	SCE (B)	SCE Exceeds ADOPT Amount (C=B-A)	SCE Exceeds ADOPT Percent (D=C/A)
	Fixed Capital				
	Fixed Capital - Beginning of Year				
1	Plant in Service	7,527,717	7,527,717	0	.0
2	Nuclear Fuel	0	0	0	.0
3	CWIP in Progress	254,640	254,640	0	.0
4	Property Held For Future Use	95,534	95,534	0	.0
5	Total Beginning of Year	7,877,891	7,877,891	0	.0
6	Weighted Average Net Additions	364,550	364,550	0	.0
7	Total Fixed Capital	$8,242,441	$8,242,441	$0	.0
	Adjustments				
8	Customer Advances For Construction	(39,799)	(39,799)	0	.0
9	Total Adjustments	($39,799)	($39,799)	$0	.0
	Working Capital				
10	Coal & Misc Fuel Stock	11,694	11,694	0	.0
11	Materials and Supplies	78,442	78,442	0	.0
12	Working Cash	(13,318)	27,000	40,318	(302.7%)
13	Total Working Capital	$76,818	$117,136	$40,318	52.5%
14	Total Before Deductions	$8,279,460	$8,319,778	$40,318	.5%
	Deductions For Reserves				
15	Depreciation Reserve	(2,810,381)	(2,810,381)	0	.0
16	Taxes Deferred - Accelerated Amort	(8,562)	(8,562)	0	.0
17	Taxes Deferred - ACRS	(125,524)	(125,524)	0	.0
18	Unfunded Pension Reserve	(26,726)	(26,726)	0	.0
19	Total Deductions For Reserves	($2,971,193)	($2,971,193)	$0	.0
20	Load Management	14,607	14,607	0	.0
21	Total Rate Base	$5,322,874	$5,363,192	$40,318	.8%

Appendix B
Page 38
SOUTHERN CALIFORNIA EDISON COMPANY
Summary of Earnings at Present Rates
(Including Songs Unit 1)
Test Year 1985

(Thousands Of Dollars)

Line No.	Description	ADOPTED	SCE	SCE Exceeds ADOPT Amount	SCE Exceeds ADOPT Percent
		(A)	(B)	(C=B-A)	(D=C/A)
	Operating Revenues				
1	Revenues	2,705,134	2,694,009	(11,125)	(.4%)
2	Total Operating Revenues	$2,705,134	$2,694,009	($11,125)	(.4%)
	Operating Expenses				
3	Base Rate Revenue Credit	1,567	1,567	0	.0
4	Production	348,149	362,074	13,925	4.0%
5	Transmission	62,384	62,976	592	.9%
6	Distribution	120,647	128,320	7,673	6.4%
7	Customer Accounts	69,547	69,603	56	.1%
8	Uncollectibles	5,732	5,707	(25)	(.4%)
9	Customer Service & Information	44,200	55,056	10,856	24.6%
10	Administrative & General	250,249	264,215	13,966	5.6%
11	Franchise Requirements	20,290	20,201	(89)	(.4%)
12	Labor Escalation Amount	61,519	69,433	7,914	12.9%
13	Non-Labor Escalation Amount	39,257	41,685	2,428	6.2%
14	Subtotal	$1,023,531	$1,080,837	$57,286	5.6%
15	Depreciation	329,662	329,662	0	.0
16	Taxes Other Than On Income	86,737	88,967	2,230	2.6%
17	California Corporation Franchise Tax	31,872	64,640	(7,232)	(7.9%)
18	Federal Income Tax	422,551	389,856	(32,696)	(7.7%)
19	Total Operating Expenses	$1,954,373	$1,973,961	$19,588	1.0%
20	Net Operating Revenues	$750,761	$720,048	($30,713)	(4.1%)
21	Rate Base	$5,322,874	$5,363,192	$40,318	.8%
22	Rate of Return	14.10%	13.42%	(.67%)	

SOUTHERN CALIFORNIA EDISON COMPANY

COST OF SERVICE SUMMARY - TEST YEAR 1985

BASE COSTS

	ITEM	TOTAL SYSTEM PRESENT	CPUC JURISDICTION PRESENT	CPUC JURISDICTION ADOPTED
1.	TOTAL OPERATING REVENUE	2,705,134	2,578,283	2,462,488
2.	OPERATING EXPENSES			
3.				
4.	BASE RATE REV CREDIT	1,567	1,476	1,476
5.	PRODUCTION	390,229	366,548	366,548
6.	TRANSMISSION	69,405	65,647	65,647
7.	DISTRIBUTION	138,632	138,255	138,255
8.	CUSTOMER ACCOUNTS	79,344	79,325	79,325
9.	UNCOLLECTIBLES	5,732	5,732	5,465
10.	CUST SRV/INFORM	49,437	49,437	49,437
11.	ADMIN & GENERAL	268,915	261,053	261,053
12.	FRANCHISE FEES	20,290	20,190	19,349
13.	SUBTOTAL	1,023,551	987,663	986,555
14.	DEPRECIATION	329,662	319,287	319,287
15.	TAXES OTHER THAN INCOME	86,737	83,821	83,821
16.	TAXES BASED ON INCOME	514,423	479,213	420,854
	SUBTOTAL TAXES	601,160	563,034	504,675
17.	TOTAL OPERATING EXPENSE	1,954,373	1,869,984	1,810,517
18.	NET REVENUE	750,761	708,299	651,971
19.	RATE BASE	5,322,874	5,133,624	5,133,624
20.	RATE OF RETURN (%)	14.10%	13.80%	12.70%

Additional Revenue Requirement for 1985	$ (115,795)
CPUC Base Rate 1985 Revenue Requirement	$2,462,488
Authorized ERAM Revenue Requirement	$2,420,436

(End of Appendix B.)

APPENDIX C

PAGE 1

IMPLEMENTATION OF BASELINE QUANTITIES
IN A THREE-STEP PROCEDURE
WINTER

Line No.	Baseline Zone (1)	Lifeline Region (2)	Lifeline End Use (3)	Lifeline Allocations (4)	One-Third Implementation (5)	Two-Thirds Implementation (6)	Baseline Quantities (7)
1.	10	W	Basic	240	258	275	293
2.	10	W	Electric Water Heating	490	424	359	293
3.	10	W	Electric Space Heat	790	726	661	597
4.	10	W	All Electric	1,040	892	745	597
5.	14	W	Basic	240	262	283	305
6.	14	W	Electric Water Heating	490	428	367	305
7.	14	W	Electric Space Heat	790	868	945	1,023
8.	14	W	All Electric	1,040	1,034	1,029	1,023
9.	15	W	Basic	240	312	383	455
10.	15	W	Electric Water Heating	490	478	467	455
11.	15	W	Electric Space Heat	790	788	787	785
12.	15	W	All Electric	1,040	955	870	785
13.	16	W	Basic	240	258	276	294
14.	16	W	Electric Water Heating	490	425	359	294
15.	16	W	Electric Space Heat	790	875	959	1,044
16.	16	W	All Electric	1,040	1,041	1,043	1,044
17.	17	W	Basic	240	258	275	293
18.	17	W	Electric Water Heating	490	424	359	293
19.	17	W	Electric Space Heat	790	762	734	706
20.	17	W	All Electric	1,040	929	817	706
21.	13	X	Basic	240	277	313	350
22.	13	X	Electric Water Heating	490	443	397	350
23.	13	X	Electric Space Heat	1,040	1,079	1,119	1,158
24.	13	X	All Electric	1,290	1,246	1,202	1,158
25.	14	X	Basic	240	262	283	305
26.	14	X	Electric Water Heating	490	428	367	305
27.	14	X	Electric Space Heat	1,040	1,034	1,029	1,023
28.	14	X	All Electric	1,290	1,201	1,112	1,023

APPENDIX C

PAGE 2

IMPLEMENTATION OF BASELINE QUANTITIES
IN A THREE-STEP PROCEDURE
WINTER

Line No.	Baseline Zone (1)	Lifeline Region (2)	Lifeline End Use (3)	Lifeline Allocations (4)	One-Third Implementation (5)	Two-Thirds Implementation (6)	Baseline Quantities (7)
1.	16	X	Basic	240	258	276	294
2.	16	X	Electric Water Heating	490	425	359	294
3.	16	X	Electric Space Heat	1.040	1.041	1.043	1.044
4.	16	X	All Electric	1.290	1.208	1.126	1.044
5.	17	X	Basic	240	258	275	293
6.	17	X	Electric Water Heating	490	424	359	293
7.	17	X	Electric Space Heat	1.040	929	817	706
8.	17	X	All Electric	1.290	1.095	901	706
9.	13	Y	Basic	240	277	313	350
10.	13	Y	Electric Water Heating	490	443	397	350
11.	13	Y	Electric Space Heat	1.360	1.293	1.225	1.158
12.	13	Y	All Electric	1.610	1.459	1.309	1.158
13.	16	Y	Basic	240	258	276	294
14.	16	Y	Electric Water Heating	490	425	359	294
15.	16	Y	Electric Space Heat	1.360	1.255	1.149	1.044
16.	16	Y	All Electric	1.610	1.421	1.233	1.044
17.	15	W	Basic	240	278	317	355
18.	15	W	Electric Water Heating	490	445	400	355
19.	15	W	Electric Space Heat	790	742	695	647
20.	15	W	All Electric	1.040	909	778	647

Note: Implementation of winter allowances: one third November 1, 1985, two-thirds November 1, 1986, and Baseline November 1, 1987.

APPENDIX C

PAGE 3

IMPLEMENTATION OF BASELINE QUANTITIES IN A THREE-STEP PROCEDURE SUMMER

Line No.	Baseline Zone (1)	Lifeline Region (2)	Lifeline End Use (3)	Lifeline Allocations (4)	One-third Implementation (5)	Two-thirds Implementation (6)	Baseline Quantities (7)
1.	10	C	Basic	240	251	262	273
2.	10	C	Electric Water Heating	490	418	345	273
3.	10	C	Electric Space Heat	240	258	277	295
4.	10	C	All Electric	490	425	360	295
5.	13	C	Basic	240	309	379	448
6.	13	C	Electric Water Heating	490	476	462	448
7.	13	C	Electric Space Heat	240	372	503	635
8.	13	C	All Electric	490	538	587	635
9.	16	C	Basic	240	254	269	283
10.	16	C	Electric Water Heating	490	421	352	283
11.	16	C	Electric Space Heat	240	307	374	441
12.	16	C	All Electric	490	474	457	441
13.	17	C	Basic	240	285	331	376
14.	17	C	Electric Water Heating	490	452	414	376
15.	17	C	Electric Space Heat	240	308	376	444
16.	17	C	All Electric	490	475	459	444
17.	13	H	Basic	520	496	472	448
18.	13	H	Electric Water Heating	770	663	555	448
19.	13	H	Electric Space Heat	520	558	597	635
20.	13	H	All Electric	770	725	680	635
21.	14	H	Basic	520	485	450	415
22.	14	H	Electric Water Heating	770	652	533	415
23.	14	H	Electric Space Heat	520	535	550	565
24.	14	H	All Electric	770	702	633	565
25.	16	H	Basic	520	441	362	283
26.	16	H	Electric Water Heating	770	608	445	283
27.	16	H	Electric Space Heat	520	494	467	441
28.	16	H	All Electric	770	660	551	441
29.	17	H	Basic	520	472	424	376
30.	17	H	Electric Water Heating	770	639	507	376
31.	17	H	Electric Space Heat	520	495	469	444
32.	17	H	All Electric	770	661	553	444

APPENDIX C

PAGE 4

IMPLEMENTATION OF BASELINE QUANTITIES IN A THREE-STEP PROCEDURE SUMMER

Line No.	Baseline Zone (1)	Lifeline Region (2)	Lifeline End Use (3)	Lifeline Allocations (4)	One-third Implementation (5)	Two-thirds Implementation (6)	Baseline Quantities (7)
1.	14	Y	Basic	740	632	523	415
2.	14	Y	Electric Water Heating	990	798	607	415
3.	14	Y	Electric Space Heat	740	682	623	565
4.	14	Y	All Electric 990	848	707	565	
5.	16	Y	Basic	740	588	435	283
6.	16	Y	Electric Water Heating	990	790	590	283*
7.	16	Y	Electric Space Heat	740	640	541	441
8.	16	Y	All Electric	990	807	624	441
9.	17	Y	Basic	740	619	497	376
10.	17	Y	Electric Water Heating	990	790	590	376*
11.	17	Y	Electric Space Heat	740	641	543	414
12.	17	Y	All Electric	990	808	626	444
13.	14	S	Basic	890	732	573	415
14.	14	S	Electric Water Heating	1,140	940	740	415*
15.	14	S	Electric Space Heat	890	782	673	565
16.	14	S	All Electric	1,140	948	757	565
17.	15	S	Basic	890	880	870	860
18.	15	S	Electric Water Heating	1,140	1,047	953	860
19.	15	S	Electric Space Heat	890	858	827	795
20.	15	S	All Electric	1,140	1,025	910	795
21.	17	S	Basic	890	719	547	376
22.	17	S	Electric Water Heating	1,140	940	740	376*
23.	17	S	Electric Space Heat	890	741	593	444
24.	17	S	All Electric	1,140	940	740	444*
25.	15	W	Basic	890	993	1,097	1,200
26.	15	W	Electric Water Heating	1,140	1,160	1,180	1,200
27.	15	W	Electric Space Heat	890	993	1,097	1,200
28.	15	W	All Electric	1,140	1,160	1,180	1,200

Note: Implementation of summer allowances: one-third on May 1, 1985; two-thirds May 1, 1986; and Baseline quantities May 1, 1987 except for * values which will not be reached until May 1, 1988 due to the 200 KWh cap.

(End of Appendix C)

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY

RATES EFFECTIVE JANUARY 1, 1985

Rates, charges, and conditions are changed to the extent set forth in this appendix. The adjustments shown below include revised rates for the Energy Cost Adjustment Clause (ECAC), Electric Revenue Adjustment Mechanism (ERAM), and Major Additions Adjustment Clause (MAAC), resulting from the decisions in A. 84-02-40, et al., and A. 84-01-11.

The Effective Rates shown below are subject to the Steel Surcharge Adjustment Clause (SSAC) as provided in Part X of the Preliminary Statement, at a billing factor of 0.026¢ per kWh.

Schedule No. D

Rates:

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Energy Charge:			
Lifeline, per kWh	4.435¢	2.137¢	6.572¢
Nonlifeline, per kWh	4.435¢	5.232¢	9.667¢

Adjustment Rates:

	Per kWh	
	Lifeline	Nonlifeline
Energy Cost Adjustment Billing Factors	0.605¢	3.700¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Schedule Nos. D-APS-1 and D-APS-2

No Change

Schedule No. DE

No Change

Schedule No. DM

No Change

Schedule No. DMS-1

No Change

Schedule No. DMS-2

The Base Rate charges shall be reduced by $6.30 per sub-metered unit per month.

Schedule No. D-PC

Rates:

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Net Energy Charge:			
Lifeline, per kWh	4.435¢	2.137¢	6.572¢
Nonlifeline, per kWh	4.435¢	5.232¢	9.667¢

Minimum Charge:
The Base Rate portion of the Net Energy Charge shall be subject to a monthly Minimum Charge of $4.44.

Adjustment Rates:

	Per kWh	
	Lifeline	Nonlifeline
Energy Cost Adjustment Billing Factors	0.605¢	3.700¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Schedule No. DWL

Rates:

	Per Lamp Per Month	
	Base Rates	Effective Rates
Lamp Charge:		
75 watt mercury vapor lamp	$6.39	$7.78

Adjustment Rates:

	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule Nos. DX-30, DX-31, and DX-32

No Change

Schedule No. DX-33

Rates:

	Per Meter Per Month	
		Effective Rates
Demand Charge:		
All kW of billing demand, per kW		$4.00

Rates:

	Base Rates	Adjustments	
Energy Charge:			
Lifeline, per kWh	1.935¢	2.137¢	4.072¢
Nonlifeline, per kWh	1.935¢	5.232¢	7.167¢

Adjustment Rates:

	Per kWh	
	Lifeline	Nonlifeline
Energy Cost Adjustment Billing Factors	0.605¢	3.700¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Schedule Nos. DX-36 and DX-37

No Change

Schedule No. CS-1

Rates:

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Energy Charge:			
All kWh, per kWh	5.407¢	4.359¢	9.766¢

Adjustment Rates:	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. CS-1-PG

Rates:

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Net Energy Charge:			
All kWh, per kWh	5.407¢	4.359¢	9.766¢

Minimum Charge:
The Base Rate portion of the Net Energy Charge shall be subject to a monthly Minimum Charge of $5.41.

Adjustment Rates:	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. CS-2

Rates:

	Per Meter Per Month		
			Effective Rates
Demand Charge:			
All kW of billing demand, per kW			$3.80
	Base Rates	Adjustments	
Energy Charge:			
All kWh, per kWh	2.909¢	4.359¢	7.268¢

Adjustment Rates:	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Voltage Discount:
The charges before adjustments will be reduced by 6% for service delivered and metered at voltages of from 2 kV through 50 kV and by 15% for service delivered and metered at voltages over 50 kV.

The provision is deleted for a greater discount when only one transformation from a transmission voltage level is involved.

Schedule Nos. CS-1-APS and CS-2-APS

No Change

Schedule Nos. I-1, I-2, I-3, and I-4

No Change

Schedule No. LS-1

Rates:

Base Rates:

Average Initial Lumens	Per Lamp Per Month: All Night Service	Energy Curtailment Service: Midnight or Facilities Equivalent	Energy Curtailment Service: Facilities Charge
Incandescent Lamps			
1,000	$ 4.05	$3.50	$2.25
2,500	5.45	4.35	3.00
4,000	6.50	5.05	2.80
6,000	7.85	5.80	3.00
10,000	10.60	7.40	3.30
Mercury Vapor Lamps			
4,000	$ 7.00	$ 6.15	$ 5.00
7,900	7.50	6.40	5.00
12,000	8.70	7.35	5.65
21,000	10.00	8.15	5.85
41,000	13.10	10.00	6.25
55,000	16.10	11.50	6.30
High Pressure Sodium Vapor Lamps			
4,000	$ 7.15	$ 6.60	$ 5.15
5,800	7.45	6.65	5.25
9,500	7.90	7.00	5.40
16,000	8.80	7.70	5.90
22,000	9.50	8.20	6.20
27,500	10.00	8.50	6.25
50,000	11.35	9.40	6.35
Low Pressure Sodium Vapor Lamps			
4,800	$15.15	$14.60	12.80
8,000	15.60	14.85	12.80
13,500	20.05	18.85	16.05
22,500	21.65	19.85	16.15
33,000	22.80	20.85	16.40

Effective Rates:

Average Initial Lumens	Per Lamp Per Month: All Night Service	Energy Curtailment Service: Midnight or Facilities Equivalent	Energy Curtailment Service: Facilities Charge
Incandescent Lamps			
1,000	$5.66	$4.28	$2.25
2,500	8.59	6.12	3.00
4,000	11.56	7.62	2.80
6,000	14.78	9.29	3.00
10,000	21.28	12.81	3.30
Mercury Vapor Lamps			
4,000	$ 9.05	$ 7.20	$5.00
7,900	10.86	8.10	5.00
12,000	13.36	9.70	5.65
21,000	17.32	11.86	5.85
41,000	25.52	16.28	6.25
55,000	33.67	20.39	6.30

	Average Initial Lumens	Per Lamp Per Month: All Night Service	Energy Curtailment Service: Midnight or Equivalent	Energy Curtailment Service: Facilities Charge
High Pressure Sodium Vapor Lamps				
	4,000	$ 8.07	$ 7.08	$ 5.15
	5,800	8.80	7.30	5.25
	9,500	9.99	8.05	5.40
	16,000	11.76	9.18	5.90
	22,000	13.42	10.16	6.20
	27,500	14.88	10.94	6.25
	50,000	18.89	13.24	6.55
Low Pressure Sodium Vapor Lamps				
	4,800	$16.11	$15.08	$12.80
	8,000	16.91	15.50	12.80
	13,500	22.27	19.98	16.05
	22,500	24.92	21.51	16.15
	33,000	26.42	22.68	16.40

Adjustment Rates:

	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. LS-2

Rates:

	Per kW of Lamp Load Per Month: Base Rates	Effective Rates
Type of Service:		
All Night Service		
Multiple Installation	$17.20	$32.69
Series Installation	22.35	42.49
Midnight or Equivalent Service		
Multiple Installation	$12.10	$19.93
Series Installation	13.55	23.72

Adjustment Rates:

	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. LS-3

Rates:

	Per Meter Per Month: Base Rates	Adjustments	Effective Rates
Energy Charge:			
All kWh, per kWh	4.847¢	4.359¢	9.206¢

Adjustment Rates:

	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	- 0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. LS-4

No Change

Schedule No. OL-1

Rates:

Base Rates:

Average Initial Lumens	Per Lamp Per Month: All Night Service	Energy Curtailment Service: Midnight or Facilities Equivalent	Energy Curtailment Service: Charge
Mercury Vapor Lamps			
7,900	$ 8.20	$ 6.80	$ 5.05
21,000	10.95	8.65	6.00
High Pressure Sodium Vapor Lamps			
5,800	$ 8.10	$ 7.03	$ 5.30
9,500	8.55	7.40	5.45
22,000	10.35	8.65	6.25

Effective Rates:

Average Initial Lumens	Per Lamp Per Month: All Night Service	Energy Curtailment Service: Midnight or Facilities Equivalent	Energy Curtailment Service: Charge
Mercury Vapor Lamps			
7,900	$11.36	$ 8.50	$ 5.05
21,000	18.27	12.36	6.00
High Pressure Sodium Vapor Lamps			
5,800	$ 9.45	$ 7.70	$ 5.30
9,500	10.64	8.45	5.45
22,000	14.27	10.61	6.25

Adjustment Rates:	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. PA-1

Rates:

	Per Meter Per Month: Base Rates	Adjustments	Effective Rates
Service Charge:			
2 hp and over connected load, per hp			$ 1.00
Energy Charge:			
All kWh, per kWh	3.242¢	4.359¢	7.601¢

Adjustment Rates:	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. PA-1-PC

Rates:

	Per Meter Per Month		
			Effective Rates
Service Charge:			
2 hp and over connected load, per hp			$ 1.00
	Base Rates	Adjustments	
Net Energy Charge:			
All kWh, per kWh	3.242¢	4.359¢	7.601¢

Minimum Charge:
The monthly Minimum Charge shall be the monthly Service Charge plus the Base Rate Net Energy Charge of 33.2¢ for the first 100 kWh.

Adjustment Rates:	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. PA-2

Rates:

	Per Meter Per Month		
			Effective Rates
Demand Charge:			
All kW of billing demand, per kW			$ 3.73
	Base Rates	Adjustments	
Energy Charge:			
All kWh, per kWh	2.426¢	4.359¢	6.785¢

Adjustment Rates:	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule Nos. S, SCC-1, SCC-2, and SCC-3

No Change

Schedule No. SE

No Change

Schedule No. SP-1

Rates:	Per Meter Per Month
Energy Charge:	
All kWh, per kWh	5.708¢

Schedule No. SP-2

Rates:	Per Meter Per Month
Energy Charge:	
All kWh, per kWh	4.485¢

Schedule No. SP-3

Rates:

	Per Meter Per Month	
	Firm Service Level Kilowatthours	Interruptible Kilowatthours
Energy Charge:		
All kWh, per kWh	5.708¢	4.485¢

Schedule No. TC-1

Rates:

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
All kWh, per kWh	4.124¢	4.359¢	8.483¢

Adjustment Rates:

	Per kWh
Energy Cost Adjustment Billing Factors	2.827¢
Annual Energy Rate	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢

Schedule No. TOU-8

Rates:

	Per Meter Per Month	
		Effective Rates
Demand Charge:		
All kW of on-peak billing demand, per kW		$ 5.05
Plus all kW of mid-peak billing demand, per kW		0.65
Plus all kW of off-peak billing demand, per kW		No Charge

	Base Rates	Adjustments	
Energy Charge:			
All on-peak kWh, per kWh	2.356¢	6.122¢	8.478¢
Plus all mid-peak kWh, per kWh	2.356¢	4.722¢	7.078¢
Plus all off-peak kWh, per kWh	2.356¢	3.552¢	5.908¢

Adjustment Rates:

	Per kWh		
	On-peak	Mid-peak	Off-peak
Energy Cost Adjustment Billing Factors	4.390¢	3.190¢	2.020¢
Annual Energy Rate	0.351¢	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢	0.094¢

Time Periods:
The summer season shall commence on the first Sunday in June and continue until the first Sunday in October of each year. The winter season shall commence on the first Sunday in October of each year and continue until the first Sunday in June.

Voltage Discount:
The charges before adjustments will be reduced by 6% for service delivered and metered at voltages of from 2 kV through 50 kV and by 15% for service delivered and metered at voltages over 50 kV.

The provision is deleted for a greater discount when only one transformation from a transmission voltage level is involved.

Schedule No. TOU-8-AFS

No Change

APPENDIX D

Schedule No. TOU-ALMP-1

Rates:

	Per Meter Per Month		
			Effective Rates
Demand Charge:			
First 6 kW or less of on-peak billing demand			$21.00
All excess of kW of on-peak billing demand, per kW			3.30
	Base Rates	Adjustments	
Energy Charge:			
All on-peak kWh, per kWh	2.177¢	8.510¢	10.687¢
Plus all off-peak kWh, per kWh	2.177¢	3.504¢	5.681¢

Adjustment Rates:

	Per kWh	
	On-peak	Off-peak
Energy Cost Adjustment Billing Factors	6.578¢	1.972¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Time Periods:
The summer season shall commence on the first Sunday in June and continue until the first Sunday in October of each year. The winter season shall commence on the first Sunday in October of each year and continue until the first Sunday in June.

Schedule No. TOU-ALMP-2

This is no longer an experimental rate schedule.

Applicability:

Applicable to power service for general agricultural purposes. This schedule is limited to customers who are separately metered by the Company, subject to meter availability.

Rates:

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Energy Charge:			
All on-peak kWh, per kWh	3.463¢	14.273¢	17.736¢
Plus all off-peak kWh, per kWh	3.463¢	2.240¢	5.703¢

Adjustment Rates:

	Per kWh	
	On-peak	Off-peak
Energy Cost Adjustment Billing Factors	12.741¢	0.708¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Time Periods:
The summer season shall commence on the first Sunday in June and continue until the first Sunday in October of each year. The winter season shall commence on the first Sunday in October of each year and continue until the first Sunday in June.

APPENDIX D

Schedule No. TOU-CS

Rates:

	Per Meter Per Month		
			Effective Rates
Demand Charge:			
All kW of on-peak billing demand, per kW			$7.00
Plus all kW of off-peak billing demand, per kW			No Charge
Energy Charge:	Base Rates	Adjustments	
All on-peak kWh, per kWh	4.147¢	9.623¢	13.770¢
Plus all off-peak kWh, per kWh	4.147¢	3.066¢	7.213¢

Adjustment Rates:

	Per kWh	
	On-peak	Off-peak
Energy Cost Adjustment Billing Factors	8.091¢	1.534¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Time Periods:
The summer season shall commence on the first Sunday in June and continue until the first Sunday in October of each year. The winter season shall commence on the first Sunday in October of each year and continue until the first Sunday in June.

Voltage Discount:
The charges before adjustments will be reduced by 6% for service delivered and metered at voltages of from 2 kV through 50 kV and by 15% for service delivered and metered at voltages over 50 kV.

The provision is deleted for a greater discount when only one transformation from a transmission voltage level is involved.

Schedule No. TOU-PA-1

Applicability:

Closed to new customers as of January 1, 1985.

Rates:

	Per Meter Per Month		
			Effective Rates
Service Charge:			
Customer Charge			$4.20
Plus per KVA of Transformer Capacity			1.50
Energy Charge:	Base Rates	Adjustments	
On-peak kWh, per kWh	2.572¢	6.423¢	8.995¢
Off-peak kWh, per kWh	2.572¢	3.449¢	6.021¢

Adjustment Rates:

	Per kWh	
	On-peak	Off-peak
Energy Cost Adjustment Billing Factors	4.091¢	1.917¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Time Periods:
The summer season shall commence on the first Sunday in June and continue until the first Sunday in October of each year. The winter season shall commence on the first Sunday in October of each year and continue until the first Sunday in June.

Schedule No. UCLT

No Change

APPENDIX D-1

SOUTHERN CALIFORNIA EDISON COMPANY

RATES EFFECTIVE MAY 1, 1985

Rates, charges, and conditions are changed as a result of decisions in A. 82-02-40, et al., and A. 84-01-11 to the extent set forth in this appendix.

Schedule No. D

Changes shall be made to accomplish the change from Lifeline to Baseline Service and to implement daily rates.

Rates:	Per Meter Per Day
Energy Charge:	
Baseline, per kWh	
Nonbaseline, per kWh	

Minimum Charge:
The Base Rate Energy Charge shall be subject to a daily Minimum Charge of $0.10.

Baseline Allowances:

Summer and Winter Baseline quantities shall be implemented consistent with the tables entitled "Implementation of Baseline Quantities in a Three-Step Procedure" which are included at the end of Appendix C.

Schedule No. D-APS-1

Daily Reduction:
$0.03 per day per connected ton of air conditioning.
$0.01 per day per connected kW of electric water heating.

Reduction Limitation:
In no event shall the amount of reduction exceed the Base Rate charge which would have resulted under the regularly filed Domestic Schedule, and the daily minimum charge of the regularly filed Domestic Schedule shall apply.

APPENDIX D-1

Schedule No. D-APS-2

Daily Reduction:

$0.05 per Summer Season Day per connected ton of central airconditioning for 50% cycling

$0.10 per Summer Season Day per connected ton of central airconditioning for 67% cycling

$0.18 per Summer Season Day per connected ton of central airconditioning for 100% cycling

Reduction Limitation:
In no event shall the amount of reduction exceed the Base Rate charge which would have resulted under the regularly filed Domestic Schedule, and the daily minimum charge of the regularly filed Domestic Schedule shall apply.

Schedule No. DE

No Change

Schedule No. DM

Changes shall be made to accomplish the change from Lifeline to Baseline Service and to implement daily rates.

Energy Charge:
The Baseline quantity to be billed under rates designated as applicable to baseline service shall be determined by multiplying the applicable baseline quantities set forth in Special Condition No. 2 of this rate schedule by the appropriate number of single-family accommodations on the meter.

Baseline Allowances:

Summer and Winter Baseline quantities shall be implemented consistent with the tables entitled "Implementation of Baseline Quantities in a Three-Step Procedure" which are included at the end of Appendix C.

APPENDIX D-1

Schedule No. DMS-1

Changes shall be made to accomplish the change from Lifeline to Baseline Service and to implement daily rates.

Daily Reduction:
The Base Rate charges shall be reduced by $0.06 per sub-metered unit per day.

Baseline Allowances:
Summer and Winter Baseline quantities shall be implemented consistent with the tables entitled "Implementation of Baseline Quantities in a Three-Step Procedure" which are included at the end of Appendix C.

Schedule No. DMS-2

Changes shall be made to accomplish the change from Lifeline to Baseline Service and to implement daily rates.

Daily Reduction:
The Base Rate charges shall be reduced by $0.23 per sub-metered unit per day.

Baseline Allowances:

Summer and Winter Baseline quantities shall be implemented consistent with the tables entitled "Implementation of Baseline Quantities in a Three-Step Procedure" which are included at the end of Appendix C.

APPENDIX D-1

Schedule No. D-PC

Changes shall be made to accomplish the change from Lifeline to Baseline Service and to implement daily rates.

Rates:	Per Meter Per Day
Net Energy Charge:	
Baseline, per kWh	
Nonbaseline, per kWh	

Minimum Charge:

The Base Rate portion of the Net Energy Charge shall be subject to a daily Minimum Charge of $0.10.

Baseline Allowances:

Summer and Winter Baseline quantities shall be implemented consistent with the tables entitled "Implementation of Baseline Quantities in a Three-Step Procedure" which are included at the end of Appendix C.

APPENDIX D-1

Schedule No. DWL

No Change

Schedule No. DX-30

Changes shall be made to implement daily rates.

In no event shall the amount of reduction exceed the Base Rate charge which would have resulted under the regularly filed Schedule No. D, Domestic Service, and the daily minimum charge of said Domestic Schedule shall apply.

Schedule No. DX-31

Changes shall be made to implement daily rates.

In no event shall the amount of reduction exceed the Base Rate charge which would have resulted under the regularly filed Schedule No. D, Domestic Service, and the daily minimum charge of said Domestic Schedule shall apply.

Schedule No. DX-32

Changes shall be made to implement daily rates.

In no event shall the amount of reduction exceed the Base Rate charge which would have resulted under the regularly filed Schedule No. D, Domestic Service, and the daily minimum charge of said Domestic Schedule shall apply.

APPENDIX D-1

Schedule No. DX-33

Changes shall be made to accomplish the change from Lifeline to Baseline Service and to implement daily rates.

Daily Charge:
The customer shall be billed as follows for each Summer Season Day.

Rates:	Per Meter Per Summer Season Day
Energy Charge:	
Baseline, per kWh	
Nonbaseline, per kWh	
Minimum Charge:	
The Base Rate Energy Charge shall be subject to a daily Minimum Charge of $0.10.	

Schedule No. DX-36

Changes shall be made to implement daily rates.

In no event shall the amount of reduction exceed the Base Rate charge which would have resulted under the regularly filed Schedule No. D, Domestic Service, and the daily minimum charge of said Domestic Schedule shall apply.

Schedule No. DX-37

Changes shall be made to implement daily rates.

In no event shall the amount of reduction exceed the Base Rate charge which would have resulted under the regularly filed Schedule No. D, Domestic Service, and the daily minimum charge of said Domestic Schedule shall apply.

Schedule No. GS-1

Changes shall be made to implement daily rates.

Rates:	Per Meter Per Day
Energy Charge:	
All kWh, per kWh	
Minimum Charge:	
The Base Rate portion of the Energy Charge shall be subject to a daily Minimum Charge of $0.20.	

Schedule No. GS-1-PC

Changes shall be made to implement daily rates.

Rates:	Per Meter Per Day
Net Energy Charge:	
All kWh, per kWh	
Minimum Charge:	
The Base Rate portion of the Energy Charge shall be subject to a daily Minimum Charge of $0.10	

Schedule Nos. GS-1-APS

Changes shall be made to implement daily rates.

APPENDIX D-1

TABLE 1

SOUTHERN CALIFORNIA EDISON COMPANY

IMPLEMENTATION OF BASELINE QUANTITIES
IN A THREE-STEP PROCEDURE

WINTER

Line No.	Baseline Zone (1)	Lifeline Region (2)	Lifeline End Use (3)	Monthly Lifeline Allocations (4)	Daily Baseline Allocations: One-Third Implementation (5)	Daily Baseline Allocations: Two-Thirds Implementation (6)	Daily Baseline Allocations: Baseline Quantities (7)
1.	10	W	Basic	240	8.6	9.1	9.7
2.	10	W	Electric Water Heating	490	17.4	18.6	19.8
3.	10	W	Electric Space Heat	790	24.1	21.9	19.8
4.	10	W	All Electric	1,040	29.6	24.7	19.8
5.	14	W	Basic	240	8.7	9.4	10.1
6.	14	W	Electric Water Heating	490	22.1	28.0	33.9
7.	14	W	Electric Space Heat	790	28.8	31.3	33.9
8.	14	W	All Electric	1,040	34.3	34.1	33.9
9.	15	W	Basic	240	10.3	12.7	15.1
10.	15	W	Electric Water Heating	490	19.5	22.7	26.0
11.	15	W	Electric Space Heat	790	26.1	26.1	26.0
12.	15	W	All Electric	1,040	31.7	28.8	26.0
13.	16	W	Basic	240	8.6	9.1	9.7
14.	16	W	Electric Water Heating	490	22.3	28.5	34.6
15.	16	W	Electric Space Heat	790	29.0	31.8	34.6
16.	16	W	All Electric	1,040	34.5	34.6	34.6
17.	17	W	Basic	240	8.6	9.1	9.7
18.	17	W	Electric Water Heating	490	18.6	21.0	23.4
19.	17	W	Electric Space Heat	790	25.3	24.3	23.4
20.	17	W	All Electric	1,040	30.8	27.1	23.4
21.	13	I	Basic	240	9.2	10.4	11.6
22.	13	I	Electric Water Heating	490	23.6	31.0	38.4
23.	13	I	Electric Space Heat	1,040	35.8	37.1	38.4
24.	13	I	All Electric	1,290	41.3	39.8	38.4
26.	14	I	Basic	240	8.7	9.4	10.1
26.	14	I	Electric Water Heating	490	22.1	28.0	33.9
27.	14	I	Electric Space Heat	1,040	34.3	34.1	33.9
28.	14	I	All Electric	1,290	39.8	36.9	33.9

Note: Implementation of winter allowances: one-third on November 1, 1985; two-thirds November 1, 1986; and Baseline quantities November 1, 1987

APPENDIX D-1

TABLE 2

SOUTHERN CALIFORNIA EDISON COMPANY

IMPLEMENTATION OF BASELINE QUANTITIES
IN A THREE-STEP PROCEDURE

WINTER

Line No.	Baseline Zone (1)	Lifeline Region (2)	Lifeline End Use (3)	Monthly Lifeline Allocations (4)	Daily Baseline Allocations: One-Third Implementation (5)	Daily Baseline Allocations: Two-Thirds Implementation (6)	Daily Baseline Allocations: Baseline Quantities (7)
1.	16	X	Basic	240	8.6	9.1	9.7
2.	16	X	Electric Water Heating	490	22.3	28.6	34.6
3.	16	X	Electric Space Heat	1,040	34.6	34.6	34.6
4.	16	X	All Electric	1,290	40.0	37.3	34.6
5.	17	X	Basic	240	8.6	9.1	9.7
6.	17	X	Electric Water Heating	490	18.6	21.0	23.4
7.	17	X	Electric Space Heat	1,040	30.8	27.1	23.4
8.	17	X	All Electric	1,290	36.3	29.9	23.4
9.	13	Y	Basic	240	9.2	10.4	11.6
10.	13	Y	Electric Water Heating	490	23.6	31.0	38.4
11.	13	Y	Electric Space Heat	1,360	42.9	40.6	38.4
12.	13	Y	All Electric	1,610	48.4	43.4	38.4
13.	16	Y	Basic	240	8.6	9.1	9.7
14.	16	Y	Electric Water Heating	490	22.3	28.6	34.6
15.	16	Y	Electric Space Heat	1,360	41.6	38.1	34.6
16.	16	Y	All Electric	1,610	47.1	40.9	34.6
17.	15	W	Basic	240	9.2	10.5	11.8
18.	15	W	Electric Water Heating	490	18.0	19.7	21.4
19.	15	W	Electric Space Heat	790	24.6	23.0	21.4
20.	15	W	All Electric	1,040	30.1	25.8	21.4

Note: Implementation of winter allowances: one-third on November 1, 1985; two-thirds November 1, 1986; and Baseline quantities November 1, 1987

APPENDIX D-1

TABLE 3

SOUTHERN CALIFORNIA EDISON COMPANY

IMPLEMENTATION OF BASELINE QUANTITIES
IN A THREE-STEP PROCEDURE

SUMMER

Line No.	Baseline Zone (1)	Lifeline Region (2)	Lifeline End Use (3)	Monthly Lifeline Allocations (4)	Daily Baseline Allocations: One-Third Implementation (5)	Daily Baseline Allocations: Two-Thirds Implementation (6)	Daily Baseline Allocations: Baseline Quantities (7)
1.	10	C	Basic	240	8.2	8.5	8.9
2.	10	C	Electric Water Heating	490	13.9	11.7	9.6
3.	10	C	Electric Space Heat	240	8.4	9.0	9.6
4.	10	C	All Electric	490	13.9	11.7	9.6
5.	13	C	Basic	240	10.1	12.4	14.6
6.	13	C	Electric Water Heating	490	17.5	19.1	20.7
7.	13	C	Electric Space Heat	240	12.1	16.4	20.7
8.	13	C	All Electric	490	17.5	19.1	20.7
9.	16	C	Basic	240	8.3	8.8	9.2
10.	16	C	Electric Water Heating	490	15.5	14.9	14.4
11.	16	C	Electric Space Heat	240	10.0	12.2	14.4
12.	16	C	All Electric	490	15.5	14.9	14.4
13.	17	C	Basic	240	9.3	10.8	12.3
14.	17	C	Electric Water Heating	490	15.5	15.0	14.6
15.	17	C	Electric Space Heat	240	10.0	12.3	14.6
16.	17	C	All Electric	490	15.5	15.0	14.6
17.	13	H	Basic	620	16.2	15.4	14.6
18.	13	H	Electric Water Heating	770	23.6	22.2	20.7
19.	13	H	Electric Space Heat	520	18.2	19.5	20.7
20.	13	H	All Electric	770	23.6	22.2	20.7
21.	14	H	Basic	520	16.8	14.7	13.5
22.	14	H	Electric Water Heating	770	22.9	20.6	18.4
23.	14	H	Electric Space Heat	520	17.4	17.9	18.4
24.	14	H	All Electric	770	22.9	20.6	18.4
25.	16	H	Basic	520	14.4	11.8	9.2
26.	16	H	Electric Water Heating	770	21.6	18.0	14.4
27.	16	H	Electric Space Heat	520	16.1	15.2	14.4
28.	16	H	All Electric	770	21.6	18.0	14.4
29.	17	H	Basic	520	15.4	13.8	12.3
30.	17	H	Electric Water Heating	770	21.6	18.0	14.6
31.	17	H	Electric Space Heat	520	16.1	15.3	14.6
32.	17	H	All Electric	770	21.6	18.0	14.6

Note: Implementation of summer allowances: one-third on May 1, 1985; two-thirds May 1, 1986; and Baseline quantities May 1, 1987, except for * values which will not be reached until May 1, 1988, due to the 200 kWh cap.

APPENDIX D-1

TABLE 4

SOUTHERN CALIFORNIA EDISON COMPANY

IMPLEMENTATION OF BASELINE QUANTITIES
IN A THREE-STEP PROCEDURE

SUMMER

Line No.	Baseline Zone (1)	Lifeline Region (2)	Lifeline End Use (3)	Monthly Lifeline Allocations (4)	Daily Baseline Allocations: One-Third Implementation (5)	Daily Baseline Allocations: Two-Thirds Implementation (6)	Daily Baseline Allocations: Baseline Quantities (7)
1.	14	V	Basic	740	20.6	17.1	13.6
2.	14	V	Electric Water Heating	990	27.7	23.1	18.4
3.	14	V	Electric Space Heat	740	22.2	20.3	18.4
4.	14	V	All Electric	990	27.7	23.1	18.4
5.	16	V	Basic	740	19.2	14.2	9.2
6.	16	V	Electric Water Heating	990	26.3	20.3	14.4
7.	16	V	Electric Space Heat	740	20.9	17.6	14.4
8.	16	V	All Electric	990	26.3	20.3	14.4
9.	17	V	Basic	740	20.2	16.2	12.3
10.	17	V	Electric Water Heating	990	26.3	20.4	14.6
11.	17	V	Electric Space Heat	740	20.9	17.7	14.6
12.	17	V	All Electric	990	26.3	20.4	14.6
13.	14	S	Basic	890	23.9	18.7	13.6
14.	14	S	Electric Water Heating	1,140	30.9	24.7	18.4
15.	14	S	Electric Space Heat	890	25.6	21.9	18.4
16.	14	S	All Electric	1,140	30.9	24.7	18.4
17.	16	S	Basic	890	28.7	28.4	28.0
18.	16	S	Electric Water Heating	1,140	33.4	29.7	25.9
19.	16	S	Electric Space Heat	890	28.0	27.0	25.9
20.	15	S	All Electric	1,140	33.4	29.7	25.9
21.	17	S	Basic	890	23.4	17.8	12.3
22.	17	S	Electric Water Heating	1,140	30.7	24.1	17.6*
23.	17	S	Electric Space Heat	890	24.2	19.3	14.6
24.	17	S	All Electric	1,140	30.7	24.1	17.6*
25.	15	M	Basic	890	32.4	35.8	39.1
26.	15	M	Electric Water Heating	1,140	37.8	35.8	39.1
27.	15	M	Electric Space Heat	890	32.4	35.8	39.1
28.	15	M	All Electric	1,140	37.8	35.8	39.1

Note: Implementation of summer allowances: one-third on May 1, 1985; two-thirds May 1, 1986; and Baseline quantities May 1, 1987, except for * values which will not be reached until May 1, 1988, due to the 200 kWh cap.

APPENDIX D-2

SOUTHERN CALIFORNIA EDISON COMPANY

RATES EFFECTIVE JUNE 2, 1985

Rates, charges, and conditions are changed to the extent set forth in this appendix.

Schedule No. TOU-8

Customer Charge
The Customer Charge is replaced by a minimum charge.

Demand Charge:

	Per kW
All kW of maximum non-coincident peak demand:	$4.00

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Summer Energy Charge:			
All on-peak kWh, per kWh	2.703¢	12.762¢	15.465¢
Plus all mid-peak kWh, per kWh	2.703¢	3.933¢	6.636¢
Plus all off-peak kWh, per kWh	2.703¢	2.311¢	5.014¢

	Summer Per kWh		
	On-Peak	Mid-Peak	Off-Peak
Adjustment Rates:			
Energy Cost Adjustment Billing Factors	11.230¢	2.401¢	0.779¢
Annual Energy Rate	0.351¢	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢	0.094¢

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Winter Energy Charge:			
All on-peak kWh, per kWh	2.703¢	12.079¢	14.782¢
Plus all mid-peak kWh, per kWh	2.703¢	3.920¢	6.623¢
Plus all off-peak kWh, per kWh	2.703¢	2.255¢	4.958¢

	Winter Per kWh		
	On-Peak	Mid-Peak	Off-Peak
Adjustment Rates:			
Energy Cost Adjustment Billing Factors	10.547¢	2.388¢	0.723¢
Annual Energy Rate	0.351¢	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢	0.094¢

Minimum Charge:
The Demand Charge plus the Base Rate portion of the Energy Charge shall be subject to a monthly Minimum Charge of $560.00.

Special Condition Nos. 3 and 4:
Delete the language providing for on-peak, mid-peak, and off-peak demand time periods.

Time Periods:

	Summer Season	Winter Season	Days
On-Peak:	12:00 p.m. to 6:00 p.m.	5:00 p.m. to 9:00 p.m.	Weekdays except holidays
Mid-Peak:	8:00 a.m. to 12:00 p.m. 6:00 p.m. to 11:00 p.m.	8:00 a.m. to 5:00 p.m.	Weekdays except holidays
Off-Peak:	All other hours	All other hours	

APPENDIX D-2

SOUTHERN CALIFORNIA EDISON COMPANY

RATES EFFECTIVE JUNE 2, 1985

Schedule No. TOU-ALMP-1

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Summer Energy Charge:			
All on-peak kWh, per kWh	2.177¢	10.834¢	13.011¢
Plus all off-peak kWh, per kWh	2.177¢	3.659¢	5.836¢

	Summer Per kWh	
	On-Peak	Off-Peak
Adjustment Rates:		
Energy Cost Adjustment Billing Factors	9.302¢	2.127¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Winter Energy Charge:			
All on-peak kWh, per kWh	2.177¢	6.665¢	8.842¢
Plus all off-peak kWh, per kWh	2.177¢	3.781¢	5.958¢

	Winter Per kWh	
	On-Peak	Off-Peak
Adjustment Rates:		
Energy Cost Adjustment Billing Factors	5.133¢	2.249¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Time Periods:

On-Peak: 12:00 p.m. to 6:00 p.m. summer weekdays
5:00 p.m. to 9:00 p.m. winter weekdays

Off-Peak: All other hours.

APPENDIX D-2

SOUTHERN CALIFORNIA EDISON COMPANY

RATES EFFECTIVE JUNE 2, 1985

Schedule No. TOU-ALMP-2

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Summer Energy Charge:			
All on-peak kWh, per kWh	3.463¢	16.985¢	20.448¢
Plus all off-peak kWh, per kWh	3.463¢	2.532¢	5.995¢

	Summer Per kWh	
	On-Peak	Off-Peak
Adjustment Rates:		
Energy Cost Adjustment Billing Factors	15.453¢	1.000¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Winter Energy Charge:			
All on-peak kWh, per kWh	3.463¢	14.075¢	17.538¢
Plus all off-peak kWh, per kWh	3.463¢	2.654¢	6.117¢

	Winter Per kWh	
	On-Peak	Off-Peak
Adjustment Rates:		
Energy Cost Adjustment Billing Factors	12.543¢	1.122¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Time Periods:

On-Peak: 12:00 p.m. to 6:00 p.m. summer weekdays
5:00 p.m. to 9:00 p.m. winter weekdays

Off-Peak: All other hours.

Schedule No. TOU-D

See attached.

APPENDIX D-2

SOUTHERN CALIFORNIA EDISON COMPANY

RATES EFFECTIVE JUNE 2, 1985

Schedule No. TOU-CS

	Per Meter Per Month
Demand Charge:	
All kW of billing demand, per kW	$1.00

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Summer Energy Charge:			
All on-peak kWh, per kWh	3.540¢	13.934¢	17.474¢
Plus all off-peak kWh, per kWh	3.540¢	2.271¢	5.811¢

	Summer Per kWh	
	On-Peak	Off-Peak
Adjustment Rates:		
Energy Cost Adjustment Billing Factors	12.402¢	0.739¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Winter Energy Charge:			
All on-peak kWh, per kWh	3.540¢	12.421¢	15.961¢
Plus all off-peak kWh, per kWh	3.540¢	2.403¢	5.943¢

	Winter Per kWh	
	On-Peak	Off-Peak
Adjustment Rates:		
Energy Cost Adjustment Billing Factors	10.889¢	0.877¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Time Periods:

	Summer Season	Winter Season	Days
On-Peak:	12:00 p.m. to 6:00 p.m.	5:00 p.m. to 9:00 p.m.	Weekdays except holidays
Off-Peak:	All other hours	All other hours	

APPENDIX D-2

SOUTHERN CALIFORNIA EDISON COMPANY

RATES EFFECTIVE JUNE 2, 1985

Schedule No. TOU-PA-1

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Summer Energy Charge:			
All on-peak kWh, per kWh	2.572¢	8.053¢	10.625¢
Plus all off-peak kWh, per kWh	2.572¢	3.585¢	6.157¢

	Summer Per kWh	
	On-Peak	Off-Peak
Adjustment Rates:		
Energy Cost Adjustment Billing Factors	6.521¢	2.053¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

	Per Meter Per Month		
	Base Rates	Adjustments	Effective Rates
Winter Energy Charge:			
All on-peak kWh, per kWh	2.572¢	6.766¢	9.338¢
Plus all off-peak kWh, per kWh	2.572¢	3.535¢	6.107¢

	Winter Per kWh	
	On-Peak	Off-Peak
Adjustment Rates:		
Energy Cost Adjustment Billing Factors	5.234¢	2.003¢
Annual Energy Rate	0.351¢	0.351¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢
Conservation Load Management Adjustment Billing Factor	0.094¢	0.094¢

Time Periods:

	Summer Season	Winter Season	Days
On-Peak:	8:00 a.m. to 11:00 p.m.	8:00 a.m. to 9:00 p.m.	Weekdays
Off-Peak	All other hours	All other hours	

Schedule No. TOU-D

DOMESTIC SERVICE - EXPERIMENTAL

TIME-OF-USE

APPLICABILITY

This experimental schedule is applicable, at the option of the utility, to domestic service including lighting, heating, cooking, and power or combination thereof in a single-family accommodation. This schedule is limited to customers that are seperately metered by the Company, subject to meter availability.

TERRITORY

Within the entire territory served.

RATES

	Per Meter Per Month
Meter Charge	$2.50
Energy Charge:	
Baseline Service:	
On-peak, per kWh	15.574¢
Off-peak, per kWh	4.012¢
Nonbaseline Service:	
On-peak, per kWh	22.907¢
Off-peak, per kWh	5.901¢

Nonbaseline Service includes all kWh in excess of applicable baseline allowances as described in Special Condition No. 3.

For service on Santa Catalina Island, the above rates are subject to the Catalina Energy Cost Balance Adjustment, as set forth in Special Condition No. 4.

Minimum Charge:

The Minimum Charge shall consist of the $2.50 Meter Charge plus a Base Rate Minimum Energy Charge of $2.00.

Charges for energy are calculated for customer billing using the components shown below.

(Continued)

Schedule No. TOU-D

DOMESTIC SERVICE - EXPERIMENTAL

TIME-OF-USE

(Continued)

ENERGY CHARGE COMPONENTS

	Per Meter Per Month Per kWh			
	Baseline Service		Nonbaseline Service	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Base Rate:				
All kWh	4.435¢	4.435¢	4.435¢	4.435¢
Adjustment Rates:				
Energy Cost Adjustment Billing Factor	9.607¢	-1.953¢	14.940¢	-0.066¢
Annual Energy Rate	0.351¢	0.351¢	0.351¢	0.351¢
Conservation Load Mgmt. Adj. Billing Factor	0.094¢	0.094¢	0.094¢	0.094¢
Electric Revenue Adjustment Billing Factor	-0.183¢	-0.183¢	-0.183¢	-0.183¢
Major Additions Adjustment Billing Factor	1.270¢	1.270¢	1.270¢	1.270¢
Total Adjustment Rates	11.139¢	-0.423¢	18.472¢	1.466¢

The Adjustment Rates are described in Parts G, I, J, and L of the Preliminary Statement. This schedule is also subject to the PUC Reimbursement Fee described in Schedule No. RF-E.

SPECIAL CONDITIONS

1. Time Periods: Time periods are defined as follows:
   On-Peak: 1 p.m. to 8 p.m., Monday through Friday
   Off-Peak: All other hours.

2. Seasonal Service: For summer cottage customers and others who normally require service for only part of the year, this schedule is applicable only on annual contract.

3. Baseline Service: The rates above are subject to adjustment as provided for in Part H of the Preliminary Statement. For purposes of billing on this schedule allowances will be allocated at 23 percent on-peak and 77 percent off-peak.

4. Catalina Energy Cost Balance Adjustment: For service on Santa Catalina Island, the rates above are subject to adjustment as provided in Part C of the Preliminary Statement, at a billing factor of 2.593¢ per kWh.

GLOSSARY

A.	Application
AB	Assembly Bill
ACRS	Accelerated Cost Recovery System
ACWA	Association of California Water Agencies
ADR	Accelerated Depreciation Rate
AER	Annual Energy Rate
AFUDC	Allowance for Funds Used During Construction
A&G	Administrative and General
ALJ	Administrative Law Judge
AMAR	Annual Major Additions Rate
ARA	Attrition Rate Adjustment
BFA	Bill Frequency Analysis
BL	Baseline
BRRAC	Base Rate Revenue Adjustment Clause
Btu	British Thermal Unit
C.	Case
CAM	Consolidated Adjustment Mechanism
CAPM	Capital Asset Pricing Model
CARB	California Air Resources Board
CCFT	California Corporate Franchise Tax
CEC	California Energy Commission
CFA	Conservation Financing Account
CFB	California Farm Bureau
C/I	Commercial/Industrial
C-I-A	Commercial-Industrial-Agricultural
CLECA	California Large Energy Consumers Association
C/LM	Conservation/Load Management
CLMAC	Conservation Load Management Adjustment Clause
CMA	California Manufacturers Association
CMR-CMC	Class Marginal Rate-Class Marginal Cost
COLA	Cost-of-Living Adjustment
CPI	Consumer Price Index
CPI-U	Consumer Price Index - All Urban Workers
CPI-W	Consumer Price Index - Urban Wage and Clerical Workers
CPUC	California Public Utilities Commission
CRA	California Retailers Association
CT	Combustion Turbine
CVAG	Coachella Valley Association of Governments
CVR	Conservation Voltage Regulation
CWIP	Construction Work in Progress

GLOSSARY

D.	Decision
DCF	Discounted Cash Flow
DOE	Department of Energy
DRI	Data Resources, Inc.
DSS	Demand Subscription Service
DWR	Department of Water Resources
E&C	Evaluation and Compliance
ECAC	Energy Cost Adjustment Clause
Edison	Southern California Edison Company
EEI	Edison Electric Institute
EEOC	Equal Employment Opportunity Commission
EPA	Environmental Protection Agency
EPD	Equal Percentage of the Difference
EPI	Equal Percentage of Increase
EPMC	Equal Percentage of Marginal Cost
EPRI	Electric Power Research Institute
ERAM	Electric Revenue Adjustment Mechanism
ERD	Energy Resources Deployment
ERTA	Economic Recovery Tax Act of 1981
EUE	Expected Unserved Energy
Farm Bureau	California Farm Bureau Federation
FEA	Federal Executive Agency
FERC	Federal Energy Regulatory Commission
FICA	Federal Insurance Contributions Act
FIT	Federal Income Tax
F/MBE	Female/Minority Business Enterprise
F&U	Franchise and Uncollectibles
GNP	Gross National Product
GRI	Gas Research Institute
HPSV	High Pressure Sodium Vapor
IDB	Industrial Development Bonds
IDC	Interest During Construction
IEP	Independent Energy Producers
IERS	Incremental Energy Rates
IHR	Incremental Heat Rate
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-hour
LLP	Large Light and Power
LNG	Liquified Natural Gas
LOLP	Loss of Load Probability
L&P	Light and Power
LRMC	Long-Run Marginal Cost
LSFO	Low Sulfur Fuel Oil
LSMP	Lighting-Small and Medium Power

GLOSSARY

MAAC	Major Attrition Adjustment Clause
MPPI	Modified Producer Price Index
NARUC	National Association of Regulatory Utility Commissioners
NOI	Notice of Intent
OII	Order Instituting Investigation
O&M	Operation and Maintenance
PACMAC	Policy Adjusted Class Marginal Cost
PG&E	Pacific Gas and Electric Company
PHFU	Plant Held for Future Use
PPI	Producer Price Index
PSD	Public Staff Division
PU	Public Utilities
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
RAF	Reliability Adjustment Factor
RCP	Rate Case Plan
RCS	Residential Conservation Service
RD&D	Research Development and Demonstration
RESO	Renewable Energy Siting Optimization
SAM	Supply Adjustment Mechanism
SAPC	System Average Percentage Charge
SAR	System Average Rate
SB	Senate Bill
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SCRUB	Schools Committee for Reducing Utility Bills
SDG&E	San Diego Gas & Electric Company
SFA	Solar Financing Account
Shareholders	California Association of Utility Shareholders
Sher Bill	Miller-Warren Energy Lifeline Act of 1975
SoCal	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
SPP	Small Power Production or Small Power Producers
SRMC	Short-Run Marginal Cost
T&D	Transmission and Distribution
TCF	Target Capacity Factor
TEFRA	Tax Equity and Fiscal Responsibility Act of 1982
TMI	Three Mile Island
TOU	Time of Use
TR	Transcript
TURN	Toward Utility Rate Normalization

GLOSSARY

Value Line	Value Line Investment Survey
WAM	Weighted Average Method
WMA	Western Mobilehome Association
WPI	Wholesale Price Index
WPI-IND	Wholesale Price Index for Industrial Commodities
WRO	Welfare Rights Organization
ZIP	Zero Interest Program

A.83-12-53
D.84-12-068

VICTOR CALVO and PRISCILLA GREW, Commissioners, dissenting in part.

We dissent from the majority's conclusions as to the rate of return on equity which should be authorized in this proceeding.

Rate of return is in its essence a matter of judgment. We do not dissent on the ground that we believe our judgment to be any more blessed by insight than that of our fellow commissioners. However, in reviewing the recommendation of the administrative law judge assigned to this case and the arguments of the parties, we concluded that the economic climate which we presently confront is vastly different from the environment which spawned the high rate of return previously awarded to this utility. Interest rates have fallen substantially and stabilized; utilities in need of capital do not face the imminent prospect of long-term or short-term borrowings at the volatile, high rates experienced in the recent past. More importantly, inflation has been significantly arrested, customer demand patterns are more predictable and energy supplies are in abundance in relation to demand. Taken together, these factors lead us to the firm belief that this utility's rate of return on equity should be reduced by this Commission.

The majority ignores the economic factors noted above and abandons risk analysis to keep this utility's rate of return at its last authorized level. The approach taken by the majority to reach this result is particularly appalling to us. The majority takes the administrative law judge's sum total revenue requirement and reduces it to eliminate expenses which it finds, with our support, unnecessary or otherwise not reasonably related to the provision of safe, reliable utility service. Rather than leaving it at that, though, the majority seems to believe that the incremental "margin" it has created between our administrative law judge's recommendation and our own conclusions leaves "room" to raise the utility's rate of return on equity. This is not an analytic or informed approach; it is simple bootstrapping.

A test year revenue requirement is the sum total of many discrete parts. Many are discussed in the decision we sign today. But, and we cannot emphasize this enough, those parts are largely distinct and separate. Reducing one expense does not justify increasing another. Such an approach pays respect and homage to the administrative law judge's "bottom line" when it deserves neither. The administrative law judge did not adopt a sum total revenue requirement; the administrative law judge only made recommendations which happened to combine to produce a final number. To treat that number as sacrosanct is to misunderstand and misapply ratemaking principles.

The majority's approach is a clear departure from any economic rigor or analysis and we cannot join in it. Therefore, we must respectfully dissent on this issue.

VICTOR CALVO
Commissioner

PRISCILLA C. GREW
Commissioner

December 28, 1984
San Francisco, California

A.83-12-53
D.84-12-068

PRISCILLA C. GREW, Commissioner, Dissenting in part:

I wish to make the following comments on the issue of rate of return in addition to those in the joint dissent which I have co-signed with Commissioner Calvo.

The majority has granted a 16 percent rate of return on common equity for Edison for the next three years. This award is disproportionately high considering Edison's relative financial risk in comparison to our other major California electric utilities. Following the Edison decision, the majority proceeded to grant Southern California Gas an unnecessary high return of 15.75 percent, to maintain its relation to Edison as adopted by the Commission in recent years. I fear we will see a similar upward ratchet effect when the majority next reconsiders the rates of return for PG&E and SDG&E. In terms of the "traditional spread", their returns are now out of line with today's disproportionate award to Edison. Of course, maintaining the spread has never been a mechanical rule at the Commission, but I fear we will hear this argument used in upcoming rate cases.

The majority asserted that the high rate of return award to Edison has no consequences for the ratepayers, because the majority removed various programs from the Edison general rate case request to offset precisely the extra dollar amount for one year caused by the return rates. The majority neglected to mention that one of the programs was not rejected, but simply transferred for consideration in another proceeding where it may eventually be adopted. It did not mention that the high return rate is for three years, not one. It did not mention that Edison will also accrue the high rate of return in the MAAC account for

San Onofre Units Two and Three, not yet part of its rate base, and ignored these additional MAAC earnings in the calculation of the "extra costs" attributable to the high rate of return. It did not mention the fundamental difference between return for the company's shareholders and expenses for programs benefitting ratepayers - it regarded them as interchangeable by arguing that reducing programs and raising return by an equal dollar amount is "a wash."

The high return award means Edison customers will be paying unnecessarily high rates for the next three years. In addition, the Edison decision already has had the spillover effect of increased rates for Southern California Gas ratepayers. In the SoCal case, the highest return recommended by our staff was 15.4 percent; the ALJ adopted 15.5 percent. The majority unnecessarily raised SoCal to 15.75 percent to maintain the traditional spread with Edison.

Now the Commission confronts a situation in which Edison has been awarded a higher rate of return that PG&E and the same rate of return as San Diego Gas and Electric. If rate of return is based on any measure of relative risk, this ranking is inconsistent with perceptions of the financial community. That community says Edison's risk is the lowest. Edison has the highest bond rating of any electric utility in California — Moody's Aa2 compared to A1 for PG&E and A2 for SDG&E.

Two years ago when I voted to set Edison's return on common equity at 16.00%, the company in my view did face substantial risk. The economic context was very different, as discussed in my accompanying dissent with Commission Calvo. San Onofre was shut down and its future was very uncertain; permanent removal from rate base was a possibility. San Onofre Two and Three were still under construction, representing a 40 percent future

incremental addition to Edison's rate base; the company was financing this construction with no cash recovery in rates. The Commission's future rate treatment for the new San Onofre units had yet to be formulated.

The majority apparently sees no change in Edison's risk position today compared to two years ago. But Edison's position has improved substantially. San Onofre Unit One is back on line, its upgrading and continuation in rate base determined to be cost effective by this Commission. Both San Onofre Units Two and Three have entered satisfactory commercial operation. With the majority's generous approval of Edison's total request in the companion San Onofre MAAC case today, Edison now enjoys an $800 million higher annual cash flow coming in from San Onofre rates today than it did two years ago. In addition, this Commission today rejected alternative ratemaking for San Onofre, which Wall Street analysts had claimed would pose an additional risk for Edison.

The majority proceeded to grant a higher return to Edison than to PG&E. In contrast to Edison, PG&E has not yet collected a dollar in rates on its controversial $5.46 billion Diablo plant. It faces complex future proceedings on the permanently closed Humboldt nuclear facility. I expect we will hear arguments that PG&E's return should be raised on the grounds that its risk position is less favorable than Edison's. I expect that SDG&E, with its bond rating substantially lower than Edison, will also come to us and say it deserves not the same rate of return as Edison, but a higher return.

The majority claimed that the one-year program reductions in the Edison general rate case request made the augmentation of the Edison return award "a wash" for the ratepayers, because it maintained the ALJ's revenue requirement for the first year.

I do not share this optimistic view. I fear the majority's decision for Edison could cost California ratepayers many tens of millions of dollars in unnecessarily high rates during the next three years.

Priscilla C. Grew

PRISCILLA C. GREW, Commissioner

December 28, 1984
San Francisco, California