ALJ/RAB/btr

Decision 90 01 048 JAN 24 1990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for: (1) Authority to Revise Its Energy Cost Adjustment Billing Factors, Its Annual Energy Rate, and Its Electric Revenue Adjustment Billing Factor Effective January 1, 1990; (2) Authority to Implement Modifications to Its Energy Cost Adjustment Clause as More Specifically Set Forth in This Application; (3) Authority to Revise the Incremental Energy Rate, the Energy Reliability Index and Avoided Capacity Cost for Avoided Cost Pricing; and (4) Review of the Reasonableness of Edison's Operations During the Period From December 1, 1987, Through March 31, 1989.	Application 89-05-064 (Filed May 30, 1989)

(Appearances are listed in Appendix A.)

OPINION

Southern California Edison Company (Edison) originally requested authority to make the following changes to its rate levels effective January 1, 1990:

1. Authorize changes in rate levels to result in a net decrease in annualized revenue of $50.4 million for the 12-month period commencing January 1, 1990. This net decrease in rate levels is comprised of a $346.3 million decrease in the Energy Cost Adjustment Billing Factor (ECABF); a $257.3 million increase in the Annual Energy Rate (AER); a $68 million increase in the Electric Revenue Adjustment Billing Factor (ERABF); and a $29.4 million decrease in base rates;

2. Change the ECABFs as follows:

   a. Baseline domestic service from 2.462 cents per kilowatt-hour (kWh) to 1.165 cents per kWh (winter) and 4.003 cents per kWh (summer);

   b. Nonbaseline domestic service from 6.894 cents per kWh to 5.670 cents per kWh (winter) and 8.508 cents per kWh (summer); and

   c. For other than domestic service, change the average ECABF from 4.373 cents per kWh to 3.312 cents per kWh (winter) and 4.487 cents per kWh (summer).

3. Change the Energy Cost Adjustment Clause (ECAC) rates to increase the AER from 0.000 cents per kWh to 0.382 cents per kWh;

4. Increase the ERABF from negative 0.304 cents per kWh to negative 0.203 cents per kWh;

5. Adjust the MAABF, CLMABF, and base rate levels to reflect the sales forecast utilized in this Application;

6. Modify Edison's ECAC tariff to terminate "lump sum" rate treatment of the carrying costs associated with fuel oil inventory, coal inventory, and in-core nuclear fuel inventory, and to terminate certain entries to the associated fuel inventory related-cost memorandum account;

7. Modify Edison's ECAC tariff to make the carrying costs associated with the fuel oil, coal, and nuclear fuel inventory levels subject to the ECABF/AER percentage allocation;

8. Modify Edison's ECAC tariff to make the gains or losses on the sale of fuel oil inventory, coal inventory, and in-core nuclear fuel inventory subject to the ECABF/AER percentage allocation;

9. Modify Edison's ECAC tariff to terminate the Chevron settlement rate; the Low Sulphur Fuel Oil (LSFO) write-down rate; and the distillate inventory write-down rate;

10. Modify Edison's ECAC tariff to include gas expenses associated with the Edison/SoCal pilot gas storage program in the ECAC balancing account, subject to the appropriate Commission-authorized ECABF/AER percentage allocation and reasonableness review;

11. Modify Edison's ECAC tariff to include the carrying costs associated with gas inventory in the ECAC balancing account, subject to the appropriate Commission-authorized ECABF/AER percentage allocation and reasonableness review.

In Decisions (D.) 88-03-026 and 88-03-079 issued in Order Instituting Rulemaking 2, the Commission ordered Edison to annually update, in its ECAC proceedings, the Incremental Energy Rate (IER) used in the calculation of avoided cost energy prices, the Energy Reliability Index (ERI), and the combustion turbine (CT) proxy deferral value used in the calculation of avoided cost capacity payments. Therefore, Edison requests that the Commission adopt the following:

1. The IER for the ECAC forecast period, time-differentiated;

2. The annual avoided capacity cost price, time-differentiated and based on:

    a. A change in the current ERI to reflect changes in resource mix and system reliability forecast for the ECAC forecast period; and

    b. A change in the current annualized CT proxy capacity cost.

If Edison's requests are approved by the Commission the net impact on various customer groups is:

Customer Group	Total Revenue Change: Dollars (In Millions)	Percentage Change
Domestic	$ 36.4	$ 1.7%
Lighting - Sm. & Med. Power	(34.0)	(1.4%)
Large Power	(40.0)	(2.4%)
Agricultural & Pumping	(7.9)	(3.9%)
Street & Area Lighting	(4.9)	(6.8%)
Total	(50.4)	(0.8%)

(Red Figure)

Edison also requested that the Commission find that:

1. Edison's fuel and energy-related costs recorded in the ECAC balancing account from December 1, 1987, through March 31, 1989, were reasonable; and

2. The incentive rewards, calculated pursuant to the Nuclear Unit Incentive Procedure and the Coal Plant Incentive Procedure, are reasonable.

These last two items were deferred to Phase 2--the Reasonableness Phase--of this proceeding and will be resolved in a subsequent decision.

The Commission's Division of Ratepayer Advocates (DRA) prepared an evaluation report on Edison's forecast and recommended, in August 1989, that Edison's rates be increased by $28 million. It sets forth its comparison:

DRA Rate Revision Proposals
(Millions of Dollars)

	SCE	DRA	Difference SCE vs. DRA
ECAC	$(346.3)	$(271.4)	$74.9
AER	257.3	265.6	8.4
ERAM	68.0	63.2	4.8
Base	(29.4)	(29.4)	0
Total	(50.4)	28.0	78.4

(Red Figure)

DRA also recommended:

1. The lump sum carrying cost of fuel oil inventory and the memorandum account for tracking any differences in the recorded and authorized carrying costs as well as any gains or losses on sales of fuel oil inventory be retained.

2. The coal and in-core nuclear fuel inventories and their associated carrying costs should continue to be treated identically with the treatment for fuel oil inventory carrying costs.

3. The balances in the Chevron Settlement, LSFO write-down, and distillate write-down accounts be transferred to the ECAC balancing account to be amortized, as requested by Edison.

4. Expenses incurred in the Pilot Gas Storage Program be recorded in the ECAC balancing account at 100% subject to refund if found to be unreasonable after review in Edison's next ECAC proceeding.

Parties actively participating in the hearing were the Cogenerators of Southern California (CSC), the California Cogeneration Council (CCC), Toward Utility Rate Normalization (TURN), the Industrial Users (IU), the California Large Energy Consumers Association (CLECA), the Federal Executive Agencies (FEA), and the California Manufacturers Association (CMA). Issues contested at the hearing, in addition to the forecast revenue change, included the IER and the IER's time-differentiated application for the forecast period; the effect of the Sacramento Municipal Utility District (SMUD)-Edison contract on rates; the proper treatment for fuel inventory related costs; the appropriate fuel oil inventory level; whether the marginal energy cost calculation should exclude the fixed demand and transportation charges; the proper revenue allocation; and rate design.

Public hearing was held before Administrative Law Judge Robert Barnett.

The Incremental Energy Rate (IER)

In 1978, the federal government enacted the Public Utility Regulatory Policies Act (PURPA), which required electric utilities to interconnect qualifying facilities (QF) to their grid and purchase all energy based on avoided cost pricing. During the forecast period, January-December 1990, Edison expects to purchase 22,253 gigawatt-hours (gWh) of energy from 326 QFs with 4,230 megawatts (MW) of dedicated capacity (approximately 3,200 MW of effective capacity). The energy and capacity expense from these QFs is expected to be $1,080.4 million and $481.7 million, respectively. The total amount of payments to QFs during the forecast period is projected to be $1,562.1 million. While QF energy is expected to supply 29% of Edison's total purchases of energy, current estimates indicate that QF expense will comprise over 59% of the fuel and purchased power expense during the forecast period.

The price paid by Edison to the QFs is determined by estimating the British thermal units (Btu) the utility would consume to produce another kilowatt hour of electricity (called the incremental energy rate or IER) and multiplying the IER by the average cost of gas to the utility. The intent is that the ratepayers be indifferent to whether the extra kilowatt hour of electricity is produced by the QF or the utility. If the IER is set too high it means that the utility could have produced that extra kilowatt hour of electricity cheaper, and the ratepayers are harmed. Set too low and the QFs are harmed.

The IER set in Edison's 1988 ECAC decision (D.88-09-031) was 9,763 Btu/kWh. In this application Edison asserts that 9,197 Btu/kWh is reasonable; DRA proposes 9,394 Btu/kWh; and two organizations representing QFs, the CCC and the CSC, propose IERs of 9,765 Btu/kWh and 9,800 Btu/kWh, respectively.

The issue of the IER is very important to Edison's ratepayers because QF payments now represent a largo, growing portion of Edison's resource mix. QF payments now represent over 30% of Edison's total resource mix, a larger portion of Edison's fuel and purchase power budget than oil and gas purchases combined. QF payments for gas-fired fuel generators are directly proportional to the IER, since energy payments to these QFs aro equal to the IER times the utility avoided gas or oil prices. Tho difference between Edison's position of 9,197 and the CSC recommended 9,800 Btu/kWh represents approximately $15 to $20 million to Edison's ratepayers in QF payments, making IERs a highly contested issue between the utility and QFs. A substantial portion of Edison's revenue requirement depends upon the magnitude of the adopted IER. The higher the IER the higher the revenue requirement.

Edison, DRA, CCC, and CSC devoted considerable testimony based upon complex computer forecasts to support their proposed IERs which support a range of forecast revenue requirement and a range of incremental energy rates. During the course of their presentations the parties discussed compromising their differences and making a joint recommendation to the Commission. Those discussions resulted in Exhibit 19 (attached as Appendix B), their recommendation that the Commission adopt an average annual IER of 9,586 Btu/kWh and a total revenue requirement reduction of $65.6 million. The time-differentiated IERs for the forecast period are recommended to be:

	Peak	Mid	Off	Super Off-Peak
Summer	13,652	8,450	8,670	N/A
Winter	N/A	10,647	9,617	8,175

The recommendations are within a reasonable zone of the expected values for revenue requirement change and IER and will be adopted. This adopted result, however, should not be construed to be acceptance of the methodology or assumptions underlying the parties' estimates of Edison's revenue requirement or the IER.

<u>Fuel Oil Inventory Level (FOIL)</u>

Edison maintains sufficient fuel oil in inventory at its generating units to sustain oil burns which could result in the forecast period from the potential shortage or curtailment of gas supplies and the unavailability of Edison's non-oil energy resources such as coal, nuclear, hydroelectric, and purchased power. Edison's and DRA's oil inventory recommendations are summarized in the table below.

<u>Comparison of Oil Inventory Recommendations</u>
(Millions of Barrels)

	SCE	DRA	Difference
Minimum Oil Inventory Level (MOIL)	3.3	3.3	0.0
Potential Oil Burn	2.7	1.2	(1.5)
Total	6.0	4.4 1/	(1.6)

1/ The column adds to 4.5 but DRA recommends 4.4.

The difference between the DRA and Edison forecasts is the amount of oil required for the Potential Oil Burn (POB) component which is the oil used to resupply individual generating units during oil burns until resupply of oil from outside sources is established. Edison urges its POB forecast should be adopted because:

- o DRA's forecast POB is based upon "average" conditions which will not ensure adequate reliability of service, whereas Edison's forecast provides sufficient reliability for the occurrence of lower probability events as well as average conditions.

- DRA's analysis did not consider the costs of not being able to serve Edison's customers but only the reduction in carrying costs associated with its recommendation, whereas Edison's analyses optimized carrying costs and the cost of unserved load.

- Moreover, DRA's approach, when corrected for the actual average number of days of gas curtailment for the period 1984 through 1988 (26 days, not 14) yields a total fuel oil level of 5.5 million barrels and would be higher if DRA had included gas curtailment data from 1989.

Thus, Edison asserts the Commission should adopt a forecast level of six million barrels for the forecast period.

DRA's forecast is based on assuming a sustained burn rate of 85,000 barrels for 14 consecutive days. Edison estimates 45 days.

On cross-examination it became apparent that DRA's two witnesses who testified regarding the proper fuel oil inventory level gave contradictory testimony. One witness testified that the potential oil burn component should be based upon the average number of days of gas curtailment sustained by Edison over the five-year period 1984-88 multiplied by an average oil burn rate of 85,000 barrels per day; and that the average number of days of gas curtailment over that five-year period was 14 days. The other DRA witness testified that he derived the 14-day average number of days of gas curtailment by averaging the four years 1984-1987. This witness said that curtailment days in 1988 and 1989 were not considered because they were dry hydro years plus 1989 had a cold winter; they were not "average year" conditions. The actual number of days of gas curtailment for the period 1984-88 was 26 days, not 14. We conclude that the witness who testified regarding the appropriate potential oil burn based his consideration on an erroneous assumption--that the average number of curtailment days during 1984-88 was 14. Had he used a 26-day average, he might have recommended a POB of 2.2 million barrels. We are not, however, going to guess at what he might have recommended. Rather, we will adopt the Edison recommendation of a 2.7 POB as it is more credible.

Edison bases its recommendations on its recent experience with the burn rates which can occur during an oil burn, the time to reliably obtain oil resupplies in the market, and the time to transport oil to its generating station. It bases its 2.7 million barrel POB forecast on the need to be able to sustain an 85,000-barrel oil burn for 45 days. Its witness testified that 45 days is crucial because it takes, on average, 45 days for Edison to begin to receive oil from its supplier, at 500,000 barrels a day, when it orders oil to replace the burn. He testified that Edison's burn days were rapidly increasing, in the period June 1988 through May 1989 Edison had 140 burn days; between June 1987-May 1988 about 43 burn days.

A POB of 2.7 million barrels provides only 32 days of burn at 85,000 barrels a day. The difference is made up by the station inventory of approximately 1.9 million barrels, which is part of the minimum oil inventory level. In winter, Edison's reserves are over 7 million barrels going down to 5.2 million in the summer months, with a yearly average of 6 million barrels.

Because the primary function of fuel oil inventory is to provide insurance against natural gas shortages or curtailments and the unavailability of Edison's non-oil energy resources, and because Edison has suffered increased curtailments over the last three years, which are greatly in excess of the 14-day curtailment forecast by DRA, we will adopt the Edison forecast of 2.7 million barrels for the POB element of its fuel oil inventory. The dollar difference between the Edison forecast and the DRA forecast is based on carrying costs for the fuel oil inventory. The carrying costs for Edison's 2.7 million barrel estimate exceeds DRA's 1.2 million barrel estimate by approximately $1,000,000.

Lump Sum Ratemaking

Edison proposes termination of lump sum ratemaking treatment for costs associated with fuel inventorios commencing January 1, 1990. Lump sum treatment means that tho utility is guaranteed a fixed sum each forecast period to covor its fuel oil costs rather than having those costs subject to balancing account treatment. Edison's proposal would subject the following costs to the applicable ECABF/AER percentage allocation:

1. Carrying costs associated with fuel oil inventory;
2. Carrying costs associated with coal inventory;
3. Carrying costs associated with in-core nuclear fuel inventory; and
4. Gains or losses on the sale of fuel oil, coal, and in-core nuclear fuel inventories.

In conjunction with the proposal to terminate lump sum ratemaking treatment, Edison also proposes terminating entries (other than accrued interest) to its fuel inventory-related cost memorandum accounts as of January 1, 1990.

Edison's proposal would treat all costs associated with fuel inventories in a manner consistent with other fuel, purchased power, and other energy-related expenses in accordance with the Commission's policy regarding the consistent rate treatment of ECAC-includable energy expenses. The Commission has previously stated:

> "It is appropriate to provide consistent rate treatment for all fuel-related expenses by including all expenses in both the AER and ECAC and giving them consistent percentage recovery." (Emphasis added.) (D.82-12-105.)

More recently, when reviewing the DRA lump sum proposal in a San Diego Gas & Electric Company's (SDG&E) ECAC proceeding, the Commission stated:

> "We decline to adopt DRA's lump sum approach for fuel oil inventory. We find no explanation as to why this particular energy expense should be segregated from other expenses and given different treatment." (D.87-12-069.)

Edison's proposal is also based upon express Commission policy regarding lump sum ratemaking treatment for fuel inventory-related costs for all electric utilities. In D.89-01-012 (Pacific Gas and Electric Company (PG&E)) the Commission stated:

> "The DRA proposal was first reviewed in Edison's ECAC proceeding, it was next reviewed in SDG&E's ECAC proceeding, and it was once again reviewed in this proceeding. The proposal has now been thoroughly explored, and based on the testimony received in this proceeding, we find that there is nothing new to add; the SDG&E decision should be the final word on the subject. Accordingly, for the reasons set forth in the SDG&E decision (D.87-12-069), <u>we conclude that the lump-sum proposal should not be adopted for any of the regulated electric utilities</u>." (Emphasis added.)

DRA argues that lump sum treatment is appropriate for fuel oil ratemaking because:

- o Lump sum treatment was established as an incentive for Edison to more closely control and monitor fuel inventory costs. Edison has not provided evidence that this ratemaking incentive has not accomplished this objective.

- o Inventories for both coal and nuclear fuel are related to plants operated as baseload units. The inventories for fossil units are maintained as a type of insurance policy, using fuel inventory when less expensive gas resources are unavailable. The lump sum has functioned to maintain this insurance policy at an optimal level.

- The language in the two decisions cited by Edison does not explicitly adopt recommendations that apply to all utilities. Only a Commission ruling can accomplish that effect.

- The Edison oil inventory system is unique to those of other utilities in California. Because of Edison's centralized facilities and its resupply strategy, Edison is in a position to more accurately control and maintain fuel inventory levels that affect its entire fossil generation system. The lump sum treatment provides an incentive to control the costs associated with this inventory that may not be relevant to other utilities.

Our most recent decisions on this subject clearly show that we prefer to treat fuel related costs consistently and that lump sum ratemaking should no longer be adopted for electric utilities. Therefore, we adopt Edison's position. The ratemaking treatment for carrying costs and gains and losses on sales associated with fuel inventories (i.e., fuel oil, coal, gas, and nuclear) should be the same as for any other fuel and purchased power expense, i.e., they should be subject to the applicable ECABF/AER percentage allocation for ratemaking treatment.

<u>Marginal Energy Costs (MEC)</u>

Edison asserts that marginal energy costs for time-of-use periods should be calculated by multiplying a fuel price by the time-differentiated marginal energy cost IERs adopted in Edison's last general rate case. In this proceeding, Edison's recommended MECs are based on the average annual IER of 9,626 Btu/kWh adopted in D.87-12-066 for the MEC calculation and an updated average price of gas, including demand and transportation charges. DRA opposes the use of the general rate case (GRC)-adopted IERs in the calculation of MECs. The FEA and IU oppose including demand and transportation charges in the calculation of MECs.

IU and FEA assert that to consider Edison's gas demand and transportation charges in the calculation of marginal energy costs is erroneous because those charges do not vary with changes in forecast energy consumption and should not be factored with the calculation. They argue that this ECAC proceeding is a proper forum to consider the issue because in D.88-04-026 we found it reasonable "to consider marginal energy costs in ECAC proceedings, because energy costs are based on fuel costs, which the ECAC proceedings are designed to quantify" (at sheets 4-5).

The testimony of IU's witness was:

> "The demand charges that Edison pays to SoCal Gas are established in SoCal's ACAP and GRC cases. An annual fixed charge is adopted based on the adopted forecast of Edison's purchases. This annual charge is collected monthly in proportion to forecast monthly sales to Edison. In other words, monthly payments on a fixed annual charge are established in the context of a SoCal gas rate case and will not change until a new charge is established in a subsequent case. Since small (marginal) changes in Edison's current consumption cannot change these forecasted volumes, they cannot be considered a part of marginal energy costs."

IU argues that Edison's large power users are responsible for over 30% of Edison's marginal energy costs. Should demand and transportation charges be excluded marginal energy costs would be about 21% lower. FEA echoes IU's arguments.

In D.87-12-066, the Commission stated that Edison's ECAC proceedings for 1989 and 1990 should not relitigate the marginal cost structure and levels adopted in that decision. In D.88-04-026, the Commission found it reasonable "to consider marginal energy costs in ECAC proceedings, because energy costs are based on fuel costs, which the ECAC proceedings are designed to quantify."

In D.87-12-066, the Commission adopted an average gas price of $2.52 per million British thermal unit (MMBtu) for calculation of MECs. This value included both transportation and demand charges. Based on D.87-12-066 and D.88-04-026, which allowed the fuel cost issues to be considered in ECAC proceedings (but not MEC structure) Edison has updated the average price of gas without incorporating any methodological change such as excluding gas demand and transportation charges as proposed by IU and FEA. Edison argues that the components of the gas price to be included or excluded in MEC calculations in this proceeding should not be changed from what was adopted in D.87-12-066. These issues should be litigated in rate cases.

Edison believes that a long-run approach to calculation of MECs provides consistent, long-term price signals to customers and results in further stability in the rates. For instance, the adoption of the MECs proposed by IU and FEA results in an increase of .15¢/kWh to domestic customers under a 100% equal percentage of marginal cost (EPMC) revenue allocation scenario, placing these customers further away from an EPMC revenue allocation at their presently authorized rate levels.

TURN argues that any change in demand that can be statistically forecast in the Southern California Gas Company (SoCalGas) Annual Cost Allocation Procedure (ACAP) will cause a change in the demand and transportation charges assigned to Edison. Only the smallest instantaneous changes which cannot be forecast will leave Edison's gas price unchanged. Thus, only in the extreme short-run can marginal cost not include gas demand and transportation charges. Marginal cost is the change in cost due to a small change in output. Over time, such small changes are captured by forecasting methodologies and lead to changes in gas transportation and demand charges.

TURN asserts that the proper gas price for calculating MEC depends on which components of the gas price change when the amount of energy produced by Edison's electric department changes. Any component of the gas price allocated by throughput will change in response to a change in electric department demand. The fact that portions of the gas price, specifically the transportation component and the demand component, change with a lag does not indicate that these components should be ignored when calculating the gas price.

The conclusion that utility electric generation (UEG) costs should be used to calculate MEC, TURN believes, is consistent with the approach taken in the two general rate case decisions issued since gas unbundling. In D.87-12-066, Edison's test year 1988 rate case, the Commission used the average cost of gas to calculate marginal energy costs. (D.87-12-066, pp. 194, 211). Similarly, the average cost of gas was used in D.88-12-085, SDG&E's 1989 test year rate case, without discussion. (D.88-12-085, p. 22, App. E). DRA (or its predecessor Public Staff Division (PSD)) supported the use of average gas prices in both those cases. PG&E's most recent ECAC decision also used the UEG rate to calculate the IER used to determine avoided cost payments. (D.88-11-052, pp. 56-57.)

In summary, TURN contends that since D.86-12-009 unbundled gas rates almost three years ago, every Commission decision considering the proper gas price to be used for calculation of marginal energy cost, avoided cost, or the IER has used a gas price based on the average cost of gas.

Edison, in summary, argues that in D.87-12-066 the Commission approved inclusion of gas demand and transportation costs as part of the gas cost used to determine marginal energy costs. The Commission later found (D.88-04-026) that the complete relitigation in intervening ECAC proceedings of marginal cost structure and levels adopted in the general rate case was inappropriate but found it reasonable to consider changes in energy costs in ECAC proceedings. Since D.87-12-066 was issued after D.86-12-009, the Commission specifically determined that marginal costs should not exclude gas demand and transportation charges for

Edison. Moreover, depending on the time horizon under consideration, gas demand charges are avoidable and are only fixed for a given period. For example, the gas demand charges paid by Edison to SoCalGas are modified on at least an annual basis to reflect changes in gas demand from prior forecast periods. Thus, changes in energy consumption will change the demand and transportation charges paid by Edison when considered over a longer time period than a year.

In regard to DRA's position, Edison argues that DRA's marginal energy cost calculation also modifies the marginal energy cost structure adopted in D.87-12-066. That decision specifically concluded:

> "...that the Commission has endorsed the calculation of two IERs--one for marginal energy cost determinations and one for avoided energy cost determinations."

DRA's use of the avoided cost IER for the determination of marginal energy cost is therefore inconsistent with D.87-12-066 and effectively changes the marginal energy cost structure. The marginal energy cost structure adopted in D.87-12-066 should be retained in accordance with D.88-04-026.

We agree with Edison and TURN; the arguments of IU, FEA, and DRA merely reiterate prior positions which we have found in recent decisions to be unpersuasive. No new facts have been adduced which cause us to change our holdings.

The Edison-Sacramento Municipal Utility District (SMUD) Contract

The issue in dispute is the treatment in 1990 of non-fuel related revenues from Edison's Power Sale Agreement (the agreement) with SMUD. Fuel related revenues from such off-system sales are routinely credited to Edison's ECAC balancing account or assigned to the AER. Only the remaining non-fuel related revenues are now disputed. The net revenues in question are approximately $30 million for 1990 (including 3 mills/kWh for incremental O&M

costs).[1] TURN believes that the revenues from this agreement should be credited to ratepayers because ratepayers pay a return on the assets and the salaries of the employees that generate the power sold to SMUD. Edison believes that the revenues from the SMUD sale during 1990 should accrue to shareholders because these revenues were not forecast during the 1988 test year general rate case (TY 1988 GRC) (Application (A.) 86-12-047). Edison agrees that the ratepayers should receive the net revenues produced by this agreement starting in 1991. The California Department of General Services supports TURN; DRA takes no position on this issue.

TURN has three responses to Edison's position. First, Edison should not be allowed to profit from its own failure to inform the Commission about the SMUD sale during the pendency of its GRC. Second, the Commission has long recognized that items with the potential financial impact of the SMUD sale should be captured between GRC test years. Finally, having Edison ratepayers pay the cost of generating power for SMUD while Edison's shareholders reap the benefits is simply inequitable.

Edison's test year 1988 GRC was filed in December 1986. Hearings on the GRC began in early 1987 and continued through September. The GRC decision (D.87-12-066) was issued on December 22, 1987. During the pendency of the GRC, Edison was negotiating the agreement with SMUD, but did not inform the Commission of this fact.

Negotiations between Edison and SMUD were as follows. Sometime before April 13, 1987, Edison began negotiating with SMUD for a possible long-term power purchase. In a letter to Edison

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1 TURN estimates the revenues to be closer to $40 million, but we have done our own analysis and believe $30 million is more conservative and prudent. The adopted ratemaking treatment will cure any inaccuracy.

dated April 13, 1987, SMUD indicated that it wished to continue negotiations for an agreement of at least five years' duration beginning on January 1, 1990 for, among other things, "Firm Power - up to 300 megawatts for at least 10 hours per day."

On August 10, 1987, SMUD issued a formal request for proposals (RFP) to supply up to 400 MW of capacity to SMUD. Edison and SMUD continued negotiations which resulted in Edison's submitting a draft agreement dated November 24, 1987. This agreement was formalized in a memorandum of understanding (MOU) signed on January 15, 1988. The MOU states in part:

> "This Memorandum of Understanding represents a binding commitment of the Parties to proceed in good faith to negotiate a definitive contract that includes the terms and conditions set forth herein on or before July 31, 1988." (Emphasis added.)

The agreement was executed August 10, 1988 and was to be made effective January 1, 1990.

TURN argues that Edison should not profit from its failure in 1987 to forecast revenue from the SMUD sale. Edison argues that because the revenues from the SMUD sale were not forecast in its GRC, it need not credit these revenues to ratepayers. Edison's position is that in test year ratemaking, the Commission adopts a forecasted level of expenses and miscellaneous revenues, including revenues from off-system sales, for the test year and the two subsequent years--the attrition years. Edison contends that since its GRC decision, D.87-12-066, did not include revenues from the SMUD sale for attrition year 1990, these revenues should accrue to shareholders.

TURN responds that the only reason that the SMUD sale revenue was not forecast in the GRC is that Edison failed to inform the Commission that it planned to enter into a power sale with SMUD that was to begin on January 1, 1990. If Edison had revealed this fact to the Commission, the proper miscellaneous revenue credit either could have been forecast for the 1990 attrition year or the issue could have been held open for reevaluation in a subsequent proceeding. TURN says that the timing of the Edison-SMUD negotiation with the timing of Edison's 1988 test year GRC reveals a clear overlap. Throughout the pendency of tho GRC, Edison was deeply involved in negotiations with SMUD. Whilo the GRC hearings were going on Edison was responding to the SMUD RFP. A month before the GRC decision was issued, Edison had reached a draft agreement with SMUD. Some three weeks after the GRC decision, Edison and SMUD signed a final binding MOU on the power sale.

Edison asserts that the SMUD negotiation was one of many power sale negotiations taking place during this period, most of which did not result in agreements and not one of which was brought to the DRA's or the Commission's attention. It argues that there is no requirement for utilities to inform the Commission of all power sales contracts that might be executed during the test year or attrition years no matter how speculative those sales might be.

Requiring a utility to inform the Commission of all possible power sales contracts, no matter how uncertain, would be poor regulatory policy in Edison's opinion. Such a requirement would be unduly burdensome to the utility and would require the Commission to examine a large number of potential power sales contracts, many of which may never be executed. The Commission would also be placed in the position of forecasting the level of off-system revenues not only for the test year, but for the attrition years as well, regardless of how speculative those estimates might be.

TURN replies that forecasted revenues and expenses in the GRC are properly adjusted to reflect extraordinary events expected to occur during attrition years. When a forecast for off-system sales revenues is adopted in the GRC for the test year and the two attrition years, the forecasted amount of these revenues need not be the same in all three years. TURN contends this is entirely consistent with the Commission's treatment of various kinds of expenses which are forecast during the GRC to arise in the attrition years. For example, in Edison's most recent GRC decision, the Commission increased base rates by $9.8 million in the 1989 attrition year "to reflect a change in jurisdictional allowance due to a decrease in FERC jurisdictional sales." (D.87-12-066, p. 41.) Similarly, additional revenuos were authorized in attrition years 1989 and 1990 to reflect the cost of time-of-use meters authorized for installation during 1989 and 1990. (Id.)

TURN cites PG&E's test year 1987 GRC, in which the Commission authorized expenses for PG&E's fleet replacement program in attrition years 1988 and 1989, where the amount adopted for 1988 was some $16 million higher than the amount adopted in the test year. (D.86-12-095, p. 228.) For attrition year 1989, an additional $2 million was authorized for this program. (Id.) In allowing these attrition expenses, the Commission noted "PG&E proposes specific treatment of the Fleet Replacement Program because the associated costs are significant. . . ." (Id.) Other attrition year allowances have been routinely granted during GRC's for expenses forecast to occur during attrition years. (See e.g., PG&E GRC, D.83-12-068 (1983)
14 CPUC 2d 15, 66.)

As all these decisions clearly demonstrate, in TURN's opinion, additional revenues can be authorized in the GRC for expenses that will increase in attrition years. By the same token, revenues that will not materialize until the attrition years can be forecast in the GRC. Therefore, TURN concludes, Edison's claim that off-system sales revenue credits are fixed in the GRC for the test year and the attrition years is simply inconsistent with Commission practice.

Edison responds that TURN's citations are inapposite. Edison argues that the common denominator of the decisions cited by

TURN is that the authorized adjustments to the attrition allowances were, and reasonably could be, identified prospectively in the general rate case. Because Edison did not have a final power purchase agreement with SMUD (or a reasonable expectation that such an agreement would be executed) during the pendency of the 1988 GRC, the 1990 off-system revenues for the SMUD sales were properly not forecast in Edison's 1988 GRC. Therefore, TURN's proposed adjustment to Edison's 1990 base rates should be rejected.

TURN, anticipating Edison's claim that revenue, if any, from the SMUD contract could not be forecast in 1988, submits that this fact still would not indicate that these revenues should go to shareholders. If the Commission had been made aware of the SMUD contract it could have simply directed that the amount of SMUD contract revenues be determined in a subsequent proceeding.

TURN cites D.84-07-108 where the Commission ordered that certain items affecting General Telephone's revenue requirement be reviewed in its 1985 attrition filing. (General Tel. GRC (1984) 15 CPUC 2d 599, 665.) In a later case, explaining why those items should be quantified in an attrition filing, the Commission stated those items "had potential revenue requirement repercussions and...we lacked sufficient data to reflect [the revenue requirement impacts] in our adopted test year 1984 results of operations." (D.85-03-042, p. 45.)

Similarly, TURN cites D.87-04-074 where the Commission, after a decision in PG&E's general rate case, test year 1987, had been issued, ordered PG&E to calculate the effects of a workforce reduction plan on its revenue requirements for the test year and succeeding years. The workforce reduction had been announced two working days before PG&E's 1987 test year GRC decision (D.86-12-095) was issued. (D.87-04-074, pp. 1, 4-5.) PG&E's 1988 attrition filing ultimately resulted in a $123 million revenue requirement decrease from the workforce reduction. (Resolution (Res.) E-3061, p. 4; Res. G-2755, p. 3.) A subsequent attrition filing for 1989 resulted in a further decreases due to the workforce reduction. (Res. E-3116, p. 3.) The Commission agreed to determine the financial impacts from the workforce reduction in subsequent attrition filings because PG&E argued that these impacts could not be determined at the time of the GRC. (D.87-04-074, p. 5.) Edison did not attempt to explain or distinguish these two cases.

In the same vein, TURN points out that this Commission has modified attrition year forecasts when events subsequent to the test year show that the utility will receive revenue to which it is not entitled. TURN cites General Telephone D.85-12-081 which authorized a 1986 attrition allowance which was modified in D.86-06-008 where we reduced General Telephone's financial attrition allowance by $9.2 million because of its lower embedded cost of debt, and D.85-12-071, followed by Resolution G-2587, where we reduced PG&E's attrition allowance by $40.4 million because PG&E's authorized rate base for 1984 exceeded its recorded rate base by some $294 million.

Edison distinguishes both cases. It argues that the change to General Telephone's 1986 attrition allowance cannot be considered a change which was not previously authorized by the Commission because a change to the embedded cost of debt is one of the specific cost components that the Commission has ordered would be examined in establishing an attrition allowance. In D.85-12-076, the Commission concluded that "Commencing with the 1986 attrition year, all utilities should reflect the updated cost of embedded debt and preferred stock in their ARA filing." Therefore, the Commission merely implemented its intent as stated in D.85-12-076 to use the updated cost of embedded debt for General Telephone in D.85-12-081. Edison contends there is no analogous provision in the attrition rate adjustment (ARA) for reconsidering the level of off-system sales, and TURN cites no such authority.

In the second decision, D.85-12-071, the Commission ordered the adjustment to PG&E's attrition allowance on the basis that: (1) PG&E was earning over its authorized rate of return, and (2) the additional earnings resulting from tho difference between recorded and authorized rate base levels were not due to management efficiency or increased productivity. Edison maintains that the factors identified in D.85-12-071 which would allow for an adjustment to an attrition allowance are not present with respect to the SMUD sales. First, Edison does not project that it will exceed its authorized rate of return during 1990. In fact, Edison estimates that its recorded 1990 rate base will be approximately $235 million greater than the level of rate base authorized by the Commission for 1990, resulting in a revenue shortfall of approximately $45 million.

Second, the power purchase agreement with SMUD is directly the result of management efficiency and increased productivity. This is the type of efficiency and productivity that the Commission has sought to promote and that will ultimately benefit ratepayers over the life of the SMUD contract. The contract between Edison and SMUD will enable Edison to more productively use its existing generating resources that would otherwise go unused. The contract will provide needed energy and capacity to SMUD's customers and will result in additional revenues that will benefit Edison's shareholders in the short-run while lowering ratepayer rates in the long-run. For all of these reasons, Edison believes, TURN's reliance on D.85-12-081 and D.85-12-071 is misplaced and TURN's position is inconsistent with sound regulatory policy.

Edison contends that SMUD revenues are economy energy sales whose non-fuel revenues should be excluded from ECAC in conformance with D.92496. TURN's response is that the SMUD sale is not an economy energy sale. The SMUD contract is a sale of a minimum of 300 MW of capacity and associated energy for 10 years.

The Commission has described economy energy as sales occurring "when it is cheaper for a utility to purchase rather than generate its energy requirements. These sales are intermittent and provide savings to both the buying and selling utility." (D.85-10-050, p. 1.) The SMUD sale is nothing like an economy energy sale, in TURN's opinion.

In order to improve overall efficiency among California utilities, TURN says, the Commission has provided incentives for utilities to make short term economy energy sales on a shared savings basis. (D.85-10-050, p. 7.) No similar reason exists for giving utilities an incentive to make long-term sales of capacity and energy using ratepayer funded assets and employees. As Edison's witness admitted during cross-examination, if the SMUD contract were to have begun in 1991 and thus had been included in forecasted rates for the 1991 test year, Edison would still have had an incentive to sign the contract so long as the contract recovered Edison's costs. PG&E did the same. PG&E also has a long-term power sale contract with SMUD. In the PG&E GRC, PG&E and the DRA agreed without dispute that the revenues from PG&E's SMUD contract should be credited to ratepayers.

Edison next argues that it is unfair to adjust rates to reflect the SMUD sale revenue because it violates the Commission's policy of allowing utilities to keep any cost savings it can generate between rate cases. TURN asserts that Edison has confused savings generated by a utility's efficiency or productivity increases with revenues generated from the sale of power produced at ratepayer expense. The former reflects the application of innovation or management acumen to reduce the cost of providing service. The latter represents the increased use of capital assets on which ratepayers pay the utility a return and employees whose salaries are paid by ratepayers.

TURN closes by observing that no conceivable reason exists to give utilities incentives to generate additional revenues by having their own ratepayers pay to generate power which they then sell to another utility. This is not an incentive to exercise business acumen, but rather an invitation to utility executives to stick their hands in the ratepayers' pockets. As the Commission noted when ordering PG&E to refund over-earnings due to unrealized forecasted rate base additions:

> "An attrition year increase is not a right of the utilities. Rather, it is a regulatory mechanism which was developed in efforts to protect California utilities from the effects of uncontrollable economic conditions, primarily inflation. We note that staff's recognition that certain adjustments to attrition year increases are appropriate when economic conditions are favorable does not constitute 'one-way back schemes.' To the contrary, under California regulatory policy, the state's utilities are provided numerous protections in the form of ECAC, ERAM, GAC and other balancing accounts. It makes sense that ratepayers should share the benefits of an improved economy, lower customer growth or other uncontrollable factors, given the many regulatory protections the utilities enjoy when economic conditions are unfavorable." (D.85-12-071, p. 14.)

Discussion

To resolve the issue we must consider two questions: (1) How would the Commission have treated the SMUD sale if the negotiations had been brought to the Commission's attention during the pendency of the 1988 test year rate case? If the Commission would have included the SMUD sale in setting the 1990 attrition year adjustment, then (2) Did Edison have a duty to inform the Commission of the pending negotiations or should we make the adjustment for 1990 regardless of whether Edison had a duty to inform?

It is clear to us that had we known of the SMUD sale during the pendency of the 1988 test year rate case we would have either included the revenue from the sale in our calculation of the

1990 attrition year (cf. Edison GRC D.87-12-066, FERC jurisdictional sales; time-of-use meter expense.) or, more likely, we would have held the item open for adjustment when the facts became known. (D.84-07-108 (General Telephone) and D.87-04-074, PG&E GRC, workforce reduction in attrition year.)

The more difficult question is whether Edison had a duty to inform us of the negotiations or whether we should adjust regardless of whether Edison had a duty to inform? In our opinion Edison had a duty to inform us of the pending sale. (Cf. Edison D.89-01-039, p. 7, Finding of Fact 8, "Edison withheld information that could have lowered the adopted cost cap.... We clearly did not intend to reward Edison for withholding information...." (p. 5).) If we would have adjusted 1990 attrition results for the sale, then Edison should not benefit from its failure to inform us. Edison certainly informed us of out-of-test year expenses it wanted included in the 1990 attrition year. It should also inform us of out-of-test-year revenue. By this holding, we are not requiring Edison to inform us of every contract in negotiation during the test year; nor are we opening the way for an attrition year rate case to adjust revenues and expenses. The SMUD sale has a major impact on revenue, which was known at the time of the GRC. Although the definition of "major impact" is of necessity imprecise, a rule of thumb guide is to ask--if the amount were an expense would the utility request an adjustment in its GRC for the attrition year? Edison and other utilities have asked for attrition year expense adjustments of a magnitude much less than $30 million. A revenue adjustment in this case, therefore, is not unreasonable.

Edison asserts that if the issue is to be raised it should be done by reopening the 1988 TY GRC. We disagree. The issue was raised in this proceeding, evidence was presented by both parties, and it was extensively briefed. To repeat this effort in another proceeding would exalt form over substance. Edison asserts that the SMUD contract is a result of management efficiency and increased productivity that the Commission seeks to promote. We disagree. Any contract that contributes to margin can be so characterized. That doesn't exempt it from being included in revenues. The increased productivity we referred to was more in line with producing the same amount of electricity at less cost. Edison argues that the SMUD sale is an off-system sale and that this Commission excludes from ECAC the non-fuel-related revenue components of such sales. But we do not exclude the non-fuel-related revenue in the test year, and the SMUD contract should have been reported in the test year. Edison has agreed that the revenue should be included in 1991. We are including it in 1990 as well.

TURN recommends that we include both fuel and non-fuel revenues in the ECAC, as a general rule, for all off-system sales. We will not adopt TURN's recommendation as it would change the basic premise of the ECAC proceeding, which is to consider fuel revenues and expenses. On occasion we have made an exception to this procedure, as in this application, but the exceptions should be infrequent. Otherwise we will be approaching full blown rate cases, which the ECAC procedure is supposed to avoid.

Ratemaking Treatment

Both the non-fuel related revenues and expenses from the SMUD contract are uncertain. Over the term of the contract the revenues will become certain, but the inherent uncertainty in allocating non-fuel related expenses prevents balancing account treatment. Those expenses have two elements: (1) incremental O&M costs associated with production of the contract energy, and (2) contribution to the utility's fixed costs. We will allow Edison to recover its incremental O&M costs by retention of a share of the non-fuel related contract revenues. The CPUC-jurisdictional share of all remaining non-fuel related revenues will go to ratepayers by crediting Edison's ERAM balancing account. In anticipation of those revenues we will reduce revenues from Edison's ERAM balancing rate by $30 million. The balancing rate reduction will have no long term impact on either ratepayers or shareholders, but will minimize future ERAM account imbalances.

The ERAM credits to ratepayers should continue until off-system sales revenues from the SMUD contract are explicitly included in setting Edison's base rates. That should occur at the beginning of attrition year 1991. We note that in D.89-08-036, regarding the proposed Edison-SDG&E merger, Edison was ordered to file a 1991 attrition application on or before March 30, 1990. That application should include the effect of SMUD revenues, returning those revenues to a forecast basis.

The only remaining ratemaking issue is the proper value for incremental O&M expenses. We could order Edison to determine the specific costs that comprise incremental O&M, but such a study would be unreasonably burdensome for the revenues considered in this application, and other parties should have the opportunity to participate. We will instead adopt TURN's value of 3 mils per kWh as a reasonable proxy for the forecast period.

We will order Edison to report back to the Commission the SMUD contract deliveries and revenues recorded during the forecast period.

Energy Sales to SMUD

TURN and Edison disagree about the amount of energy Edison will sell to SMUD in 1990. TURN believes, based on the ALJ's ruling in the 1990 PG&E ECAC (A.89-04-001), that 1,190 gWh is a reasonable forecast for use in this proceeding. Edison initially forecast sales of 790 gWh, but reduced its forecasted sales in its rebuttal testimony and is now forecasting 519 gWh.

Edison initially estimated sales of 790 gWh by assuming that SMUD would purchase 300 MW of year-round capacity at an annual capacity factor of 30%. In making its initial estimate, Edison acknowledged that the amount of energy SMUD would purchase was dependent on the continued operation of the Rancho Seco Nuclear

Plant (Rancho Seco). On June 6, 1989, the SMUD electorate voted to permanently close Rancho Seco, which will cause SMUD to buy more rather than less energy. We observe that in recognition of the Rancho Seco shutdown, the CEC recommended that the basic data set used in I.89-07-004 (the Biennial Resource Plan Update) be changed to reflect the shutdown of Rancho Seco. The CEC forecasts Edison's 1990 sales to SMUD at 1,524 gWh.

Edison decreased its forecast because it concluded that sales to SMUD were likely to begin in June rather than in January 1990, a conclusion stemming from activities at FERC. For Edison to serve SMUD a PG&E interconnection is required. In mid-1989, PG&E filed an interconnection rate schedule with FERC which covered, among other things, rates for the PG&E portion of the Edison-SMUD deliveries. SMUD objected to the filing and requested a suspension to June 1, 1990. Edison assumed the request would be granted. It was not. On October 31, 1989, FERC issued its opinion (Re PG&E, Docket ER89-475-000) accepting PG&E's proposed rates for filing and suspending them, to become effective on January 1, 1990, subject to refund.

Because of these events, and especially the effect of the FERC order allowing purchases to begin January 1 rather than June 1, we believe that Edison's current estimate of 519 gWh understates the amount of energy it will sell to SMUD. In contrast, TURN's 1,190 gWh estimate is reasonable under the circumstances of this case. This estimate is toward the middle of the estimated range for Edison's sale to SMUD (from the CEC's 1,524 gWh to Edison's 519 gWh) and has the additional advantage of allowing the Commission to use consistent forecasts of the same activity in different proceedings.

Revenue Allocation

Edison, supported by DRA and TURN, proposes that the revenue requirement authorized in this proceeding be allocated to customer groups using a weighted average of 2/3 EPMC and 1/3 system average percent change (SAPC) revenue allocation with a 2.5% cap on increases to customer groups over SAPC. They maintain this revenue allocation is consistent with the Commission's policy to move all customer groups toward EPMC and considers the circumstances existing at this time to mitigate rate impacts to the domestic customer group.

In D.87-12-066, Edison's TY 1988 GRC decision, we adopted the policy to move all customer groups toward EPMC based upon the circumstances existing at the time of the rate change. This means that, to the extent practical, the total revenue requirement should be allocated to customer groups based upon their share of the utility's marginal cost. In D.88-09-031, in Edison's 1988 ECAC proceeding, and D.89-06-049, in Edison's 1989 ECAC "trigger" proceeding, we continued to move rates toward EPMC using a weighted average of 1/3 EPMC and 2/3 SAPC revenue allocation with a 2.5% cap over SAPC on increases to customer groups. Consistent with these decisions, Edison's revenue allocation proposal moves all customer groups closer to EPMC while mitigating rate impacts for the domestic customer group.

FEA proposes to allocate Edison's revenue requirement 100% EPMC with no cap. CLECA recommends 100% EPMC revenue allocation with a 5% cap on increases above and decreases below SAPC for all customer groups. IU recommends 100% EPMC revenue allocation with a maximum percentage increase assigned to any customer group of 7.5%.

Basically, FEA, CLECA, and IU raise three issues in opposition to Edison's proposed revenue allocation. They contend that (1) the Commission intended to achieve full EPMC revenue allocation by 1990 regardless of the existing circumstances; (2) Edison's proposal does not make enough movement toward full EPMC at this time; and (3) Edison's weighted average SAPC/EPMC revenue allocation dilutes the effect of marginal costs in the revenue allocation process.

These opposed to Edison's proposal base their opposition on Finding of Fact 299 in D.87-12-066:

> "Because the intent of this decision is to achieve a full EPMC revenue allocation for Edison by 1990, it is reasonable to reflect this intent in any revenue allocation proposed for Edison in 1989 and 1990."

But they fail to give due weight to our statement in the same decision that:

> "We intend to achieve full EPMC revenue allocation for Edison as soon as possible,... We believe, however, that to achieve our goal of full EPMC and ensure rate stability the adopted revenue allocation for the two years following the test year should be based on the circumstances existing at that time."

Clearly, we did not intend to achieve full EPMC by 1990 without considering other circumstances such as adverse rate impacts.

The second issue raised by the opponents addresses the question of how far the domestic customer group should move toward EPMC in this proceeding. Since the 1988 GRC, the domestic customer group average rate has increased significantly. On January 1, 1988, Edison's domestic customer group rates were increased 5.5% above the system average change. Then, on October 1, 1988, nine months later, the domestic customer group received an increase that was 2.5% above the system average change. On July 1, 1989, another nine months later, they received an increase that was again 2.5% above the system average change. Now, it is proposed that on February 1, 1990, eight months after the last movement toward EPMC, the domestic customer group receive an increase that is once again 2.5% above the system average change. Revenue allocation proposals offered by those in opposition could increase domestic rates as much as 8.7%. A cap greater than 2.5% over the system average change is excessive when coupled with the recent increases and the consistent, steady movement toward EPMC that the domestic customer group has made over the past few years.

The third issue raised by the opponents is that a combination of SAPC and EPMC does not provide enough emphasis on the role of marginal energy costs in revenue allocation. However, we have consistently used this approach for Edison. The revenue allocation adopted both in D.88-09-031 and D.89-06-049 used a weighted average SAPC/EPMC revenue allocation as well as a cap of 2.5%. Thus, it has been our judgment that the combination of SAPC and EPMC proposed by Edison, DRA, and TURN has properly reflected the effects of marginal energy cost in the movement toward EPMC.

A revenue allocation of a weighted average of 2/3 EPMC, 1/3 SAPC with a 2.5% cap is reasonable and will be adopted. It is set forth in Appendix D.

Rate Design

Edison and DRA have not proposed any changes to the methodology adopted for designing rates, including large power rates, from those adopted in D.87-12-066 and D.88-09-031. In compliance with those decisions, Edison (1) set the off-peak energy rate at 5¢/kWh (absent the Public Utilities Commission Reimbursement Fee (PUCRF)), (2) set the on- and mid-peak energy rates (where applicable) based upon the proposed marginal energy cost ratios, and (3) increased or maintained customer and demand charges in accordance with DRA's class equal percent change (CEPC) rate design adopted in D.88-09-031.

In D.88-04-026, on page 21, the Commission stated in Conclusion of Law 5:

> "Edison's intervening ECAC and offset proceedings prior to its next general rate case should not serve as forums for the relitigation of the marginal cost structure, rate design, or revenue allocation policies adopted in D.87-12-066." (Emphasis added.)

FEA believes that Edison should base its rate levels on a 100% EPMC rate design. FEA contends that Edison's present rates overcharge high load factor customers. In addition IU believes that the Commission should reconsider the present method of treating rate design considering the delay of Edison's next GRC. In order to realign time-of-use (TOU)-8 rate components with their EPMC relationships, IU recommends generally increasing the demand charges and decreasing energy charges.

Since D.88-04-026 prohibits the relitigation of rate design policies adopted in D.87-12-066 until Edison's next GRC, the GRC-adopted rate design policies used by Edison should be adopted in this proceeding.

Edison and DRA propose to reduce the domestic nonbaseline rate to baseline rate ratio in order to gradually begin phasing out the existing differential consistent with Senate Bill 987 by increasing the baseline rate 2.5% more than the domestic customer group's average increase. The remainder of the domestic revenue requirement was allocated to the nonbaseline rate, increasing this rate by 1.1% and subsequently reducing the nonbaseline rate to baseline rate ratio from the current ratio of 1.53:1 to 1.46:1. No parties have raised any objections to this proposal and it should be adopted.

Edison proposed a correction to two agricultural and pumping schedules, TOU-ALMP-2 and TOU-PA-1 (which are both closed to new customers). Rates are designed for these schedules on a different basis than most of Edison's seasonal time-of-use agricultural and pumping schedules as the rate design methods prior to 1988 were maintained. In doing so, the winter mid-peak rate is gradually becoming greater than the summer on-peak rate for the energy charges. Edison submitted an alternative rate design proposal that corrects this problem and does not significantly adversely impact customers. No parties have objected to this proposal. We will adopt the alternative rate design proposals for Schedules TOU-ALMP-2 and TOU-PA-1.

Other Issues

1. Termination of LSFO and Distillate Inventory Write-down Rates and Chevron Settlement Rate

Edison proposed termination of the LSFO inventory write-down rate, the distillate inventory write-down rate, and the Chevron contract settlement rate effective January 1, 1990. Edison also proposed that effective January 1, 1990, the remaining balances in these accounts be transferred to the ECAC balancing account for amortization. DRA agrees with Edison's proposal. We will adopt it.

2. Reinstatement of the AER

By order of D.88-05-074 and D.89-01-040, the AER was suspended pending a final order in the forecast phase of this proceeding. Edison recommends that the Commission adopt an AER of .381¢/kWh effective January 1, 1990, offset by an equal and opposite ECABF change of .381¢/kWh so that there will be no change in total ECAC rate levels effective January 1, 1990. Fuel and purchased power costs will be recoverable on the basis of the applicable ECABF/AER percentage allocation. The AER and the ECABF that are consistent with Appendix C will be effective February 1, 1990, and there will be no need for the equal and opposite AER and ECABF changes on February 1, 1990.

3. Seasonal Adjustment to Rates

As part of its rate consolidation proposal, Edison proposed a change (effective January 1, 1990) that would mitigate the undercollection in the ECAC balancing account in the summer and overcollection in the winter. Under Edison's current rate structure, the ECABF does not vary appreciably, on a cents per kilowatt hour basis, between summer and winter. Yet, Edison's fuel and purchased power expenses are higher in the summer than in the winter which has caused undercollections in the summer of up to $250 million. At the same time, Edison's current base rate structure produces more base rate revenues in the summer months compared to the winter months which causes seasonal earnings fluctuations.

Edison made the following proposal which affects the domestic class only and which was unopposed by any party:

Increase summer ECABFs by $250 million;

Decrease summer base energy rates by $250 million;

Decrease winter ECABFs by $250 million; and

Increase winter base energy rates by $250 million.

These changes are both rate and revenue neutral and will be adopted.

4. <u>Energy Reliability Index</u>

DRA and Edison both recommended that the Commission adopt an ERI of 0.0 for the forecast period. No party opposed this recommendation. It will be adopted.

5. <u>Low Income Ratepayer Assistance Program</u>

D.89-09-044 authorized the implementation of a low income ratepayer assistance (LIRA) program. In compliance with that decision, Edison calculated a LIRA program low income surcharge (LIS) of .028¢/kWh designed to recover the costs of the LIRA program. The LIS is based on the kWh sales and domestic customer group rate levels proposed by Edison in this proceeding and the determinants adopted in D.89-09-044. The LIS should be made effective on the effective date of the authorized ECAC rate change by advice letter filing. No party opposed this recommendation. It will be adopted. The revenue effect is set forth in Appendix D.

6. <u>Modeling Recommendation of the DRA</u>

DRA claims that there are unresolved modeling issues remaining in this proceeding. DRA recommends that the Commission issue an order that Edison file its ECAC revenue requirement and avoided cost IER based on the output from the same production cost model. Edison says that it is well aware of the Commission's preference to use a consistent production cost model for both revenue requirement and IER calculations and has also indicated a similar preference. Edison has committed considerable resources to develop the data base necessary to do so. Therefore, Edison intends to submit its next ECAC filing using a production cost model to forecast both revenue requirement and IER. A Commission order compelling Edison to do so is unnecessary.

7. Agricultural and Pumping Intra-class Revenue Allocation

The California Farm Bureau Federation advocates the need for intra-class revenue allocation for all agricultural rate schedules contending that there may be inappropriate collections within the class. Edison has agreed to provide marginal cost revenues for rate schedules PA-1, PA-2, TOU-PA-1, TOU-PA-B, and TOU-ALMP-2 by the next general rate case. However, in Edison's opinion, whether such information will result in a decrease in revenue allocated to the agricultural and pumping group is unclear at this time. Data is now being collected but it may not be sufficient.

8. Pilot Gas Storage Program

Edison is participating in a Commission authorized gas storage program developed by SoCalGas. This is a pilot program and Edison's ability to effectively utilize gas storage is not proven. Therefore, Edison did not reflect expenses associated with the pilot program in its 1990 fuel and purchase power forecast. DRA also did not forecast the expenses associated with this program in the forecast period. DRA recommends that 100% of the expenses incurred by Edison for this program be recorded in the ECAC balancing account subject to refund if found to be unreasonable in the next ECAC proceeding. In general, all fuel inventories should be treated in a manner consistent with all other fuel and energy expenses. However, because both DRA and Edison agree that the expenses associated with this pilot program cannot be forecast with reasonable certainty, Edison does not object to DRA's recommendation. It will be adopted.

Rate Increase

The rate increase authorized by this decision is $59.6 million to be effective February 1, 1990. The following table sets forth the revised estimates as of September 5, 1989 of Edison and DRA for the accounts in issue in this proceeding (except the Edison-SMUD contract), plus their recommended adoption and our actual adopted rate revision. Our adopted rate revision differs from the Edison/DRA recommendation because it is based on more recent information.

ECAC Proceeding
Edison-DRA Rate Revision Proposals
(Millions of Dollars)*

	SCE (Revised 9/5/89)	DRA (Revised 9/5/89)	Recommended Adoption	Adopted
ECAC	$(322.2)	$(359.5)	$(355.7)	$(354.7)
AER	260.0	255.8	256.2	256.3
ERAM	63.2	63.2	63.2	63.2
Base	(29.9)	(29.4)	(29.4)	(29.9)
MAAC	(0.3)	0	0	(0.3)
TOTAL	(29.1)	(69.9)	(65.6)	(65.4)

(Red Figure)

* Totals may not add due to rounding.

Edison proposed to consolidate several rate changes currently scheduled to occur between September 1989, and February 1, 1990, into a single rate level change effective February 1, 1990, with revenue allocation and rate design as found to be reasonable in this decision. All parties concurred in this proposal. We will include in the consolidation our adjustment for anticipated Edison-SMUD contract revenues and the LIRA program surcharge.

The rate changes to be consolidated are set forth in the table below. A more detailed estimate is set forth in Appendix C.

Proposed Revenue Consolidation
(Millions of Dollars)

Line No.	Rate Action	Sept. 19 1989 (1)	Jan. 1 1990 (2)	Jan. 20 1990 (3)	Feb. 1 1990 (4)	Total (5)
1.	Palo Verde 2[2]	$20.2	$ -	$ -	$ -	$ 20.2
2.	Palo Verde 3[3]	-	-	20.2	-	20.2
3.	Palo Verde 1[4]	-	-	-	72.3	72.3
4.	1990 Attrition[5]	-	40.5	-	-	40.5
5.	ECAC Proceeding	-	(65.4)	-	-	(65.4)
6.	SMUD non-fuel revenues	-	-	-	(30.0)	(30.0)
7.	LIRA program	-	-	-	1.8	1.8
8.	Total	20.2	(24.9)	20.2	44.1	59.6

(Red Figure)

2 Advice Letter 841-E, filed 7/21/89.

3 Advice Letter 851-E, filed 11/13/89.

4 Advice Letter 852-E, filed 11/13/89.

5 Based on return on common equity of 12.85% (D.89-11-068) and Resolution E-3172.

This decision was first issued as a proposed decision. All parties filed comments pursuant to Rule 77. We have reviewed the comments and find them unpersuasive except for changes resulting from (1) technical items, (2) more current information regarding rate changes from other proceedings which are being incorporated herein, and (3) a reconsideration of the fuel oil inventory level. The result of these changes is that rates will be increased by $59.6 million rather than $43.6 million. The fuel oil inventory level change adds approximately $1,000,000 to the increase; the increase in rate of return in D.89-11-068 adds approximately $15,000,000.

Pursuant to Rule 76.54, TURN requests a finding of eligibility for compensation in this proceeding. TURN alleges that in D.89-04-021 it has been found to have met its burden of showing financial hardship for calendar year 1989 and estimates the compensation to be sought as approximately $37,000.

Findings of Fact

1. An average annual IER of 9,586 Btu/kWh is reasonable.

2. The time-differentiated IERs for the forecast period are:

	Peak	Mid	Off	Super Off-Peak
Summer	13,652	8,450	8,670	N/A
Winter	N/A	10,647	9,617	8,175

3. It is reasonable to adopt a fuel oil inventory level of 6.0 million barrels. The reasonable estimate of the potential oil burn component of the inventory is 2.7 million barrels.

4. Lump sum ratemaking should not be used in this ECAC. The ratemaking treatment for carrying costs and gains and losses on sales associated with fuel inventories (i.e., fuel oil, coal, gas, and nuclear) should be the same as for any other fuel and purchased power expense, i.e., they should be subject to the applicable ECABF/AER percentage allocation for ratemaking treatment.

5. Marginal energy costs for time-of-use periods should be calculated by multiplying a fuel price by the time-differentiated marginal energy cost IERs adopted in Edison's last general rate case.

6. Edison's gas demand and transportation charges should be included in the calculation of marginal energy costs as we did in the D.87-12-066.

7. The use of avoided cost IERs for the determination of marginal energy cost is inconsistent with D.87-12-066 and should not be adopted.

8. The net non-fuel related revenues in 1990 from Edison's power sale agreement with SMUD should be credited to ratepayers in 1990. The amount of those revenues is approximately $30 million.

9. Edison's test year 1988 general rate case was filed in December 1986 and a decision was issued December 22, 1987. During the pendency of the general rate case Edison was negotiating the agreement with SMUD, but did not inform the Commission of this fact. On April 13, 1987, SMUD told Edison that it was to continue negotiations for an agreement of at least five years duration beginning January 1, 1990, for among other things, firm power up to 300 MW for at least 10 hours a day.

10. On August 10, 1987, SMUD issued a formal request for proposal to supply up to 400 MW of capacity. On September 18 Edison responded to that proposal; SMUD indicated in October or November that it was favorably inclined to accept Edison's proposal. Edison submitted a draft agreement on November 24, 1987 to SMUD. This agreement was formalized in a memorandum of understanding signed January 15, 1988.

11. At no time during the pendency of the 1988 rate case did Edison inform the Commission or its staff of the pending Edison-SMUD contract. Had we known of the SMUD contract during the pendency of the 1988 test year rate case we would have either

included the revenue from the sale in our calculation of the 1990 attrition year or, more likely, we would have held the item open for adjustment when the facts became known.

12. Edison had a duty to inform us of the negotiations as the SMUD sale had a major impact on revenue which was known at the time of the general rate case.

13. Until non-fuel related revenues from the SMUD contract are explicitly included in determination of base rates, it is reasonable to allow Edison to recover its incremental O&M costs at a rate of 0.3 cents per kWh. All remaining CPUC-jurisdictional non-fuel related revenues should be credited to Edison's ERAM balancing account.

14. The reasonable estimate of sales from Edison to SMUD in 1990 is 1,190 gWh.

15. It is reasonable to allocate the revenue requirement authorized in this proceeding to customer groups using a weighted average of 2/3 EPMC and 1/3 SAPC with a 2.5% cap over SAPC on increases to customer groups. This revenue allocation is consistent with the Commission's policy to move all customer groups toward EPMC and considers the circumstances existing at this time to mitigate rate impacts to the residential customer group.

16. The rate design proposed by Edison is reasonable and will be adopted. It is set forth in Appendix E. D.88-04-026 prohibits the relitigation of rate design policies adopted in D.87-12-066 until Edison's next general rate case.

17. It is reasonable to terminate the LSFO inventory write-down rate, the distillate inventory write-down rate, and the Chevron contract settlement rate effective February 1, 1990. The remaining balances in these accounts shall be transferred to the ECAC balancing account for amortization.

18. It is reasonable to adopt an AER of .381¢/kWh effective February 1, 1990. Since the AER and the ECABF consistent with Appendix C will be effective February 1, 1990, there will be no

need for the equal and opposite AER and ECABF changes on January 1, 1990. Fuel and purchased power costs will be recoverable on the basis of the applicable ECABF/AER percentage allocation.

19. Edison's proposal to mitigate the undercollection in the ECAC balancing account in the summer and overcollection in the winter is reasonable and is adopted.

20. An ERI of 0.0 for the forecast period is reasonable and is adopted.

21. A LIRA program low income surcharge of .028¢/kWh is reasonable and is adopted.

22. Edison shall submit in its next ECAC filing a production cost model to forecast both revenue requirement and IER.

23. Edison shall provide marginal cost revenue in its next general rate case for rate schedules PA-1, PA-2, TOU-PA-1, TOU-PA-B, and TOU-ALMP-2.

24. One-hundred percent of the expenses incurred by Edison for the pilot gas storage program shall be recorded in the ECAC balancing account subject to refund if found to be unreasonable in the next ECAC proceeding.

25. It is reasonable to increase rates for Edison by $59.6 million to be effective February 1, 1990 in accordance with the table set forth on page 38 of this decision, which is found reasonable.

26. The consolidation of several rate changes as proposed by Edison is reasonable.

27. It is reasonable to reduce Edison's ERAM balancing rate in the amount of $30 million annually, in anticipation of revenues credited from the SMUD contract.

28. The increases in rates and charges authorized by this decision are justified, and are just and reasonable. The adopted rates are set forth in Appendix E.

29. TURN has met the requirement of Rule 76.54(a) and is found eligible for compensation in this proceeding.

Conclusion of Law

The application should be granted to the extent set forth in the following order.

ORDER

IT IS ORDERED that:

1. A 10% annual energy rate (AER) is reinstated for Southern California Edison Company (Edison) effective February 1, 1990.

2. An average annual incremental energy rate (IER) of 9,586 British thermal units per kilowatt-hour (Btu/kWh) should be used to determine the price paid by Edison to qualifying facilities (QF).

3. The fuel oil inventory level for forecast year 1990 is 6.0 million barrels.

4. Lump sum ratemaking should not be used for costs associated with fuel inventories. The carrying costs and gains and losses on sales associated with fuel inventories are subject to the applicable energy cost adjustment billing factor (ECABF)/AER percentage allocation. Edison should file tariffs in accordance with its proposal to terminate entries to its fuel inventory related memorandum accounts, except for accrued interest, until such time that the Commission has rendered a decision regarding the reasonableness of the entries to the memorandum accounts.

5. Until non-fuel related revenues from its power sale agreement with Sacramento Municipal Utility District (SMUD) are explicitly included in determination of base rates, Edison shall credit the jurisdictional share of such revenues, less the jurisdictional share of 0.3¢/kWh, to its Electric Revenue Adjustment Mechanism (ERAM) balancing account. These credits shall become effective coincident with the other rate changes authorized by this decision.

6. The revenue requirement authorized in this proceeding shall be allocated 2/3 equal percentage of marginal cost (EPMC) and 1/3 system average percent change (SAPC) with a 2.5% cap over SAPC.

7. The low sulphur fuel oil (LSFO)inventory write-down rate, the distillate inventory write-down rate, and the Chevron contract settlement rate are terminated effective February 1, 1990. The remaining balances in these accounts shall be transferred to the energy cost adjustment clause (ECAC) balancing account for amortization.

8. An AER of .381¢/kWh is adopted effective February 1, 1990.

9. Fuel and purchased power costs will be recoverable on the basis of 90% ECABF/10% AER effective February 1, 1990 through the remainder of the forecast period.

10. Edison may mitigate the undercollection in the ECAC balancing account in the summer and overcollection in the winter in accordance with its proposal in this proceeding.

11. An energy reliability index (ERI) of 0.0 for the forecast period 1990 is reasonable and is adopted.

12. A low income ratepayer assistance (LIRA) program surcharge of .028¢/kWh is reasonable and is adopted.

13. Edison may file on three days' notice to the Commission and to the public tariffs setting forth the adopted rates set forth in Appendix E of this decision, to be effective no earlier than February 1, 1990.

14. Rates approved under Advice Letters for Palo Verde Units 1, 2, and 3 shall be effective February 1, 1990.

15. Rate changes approved for Edison's 1990 financial attrition, in A.89-05-021, and operation attrition, by Advice Letter No.850-E, shall be effective February 1, 1990.

16. Edison shall reduce its ERAM balancing rate enough to reduce revenues by $30 million annually, effective coincident with the other rate changes authorized by this decision.

17. Edison shall file revised monthly distribution percentages under the ERAM as contained in Appendix C to Exhibit 6 in this proceeding, in accordance with the procedure set forth therein.

18. On or before February 15, 1991, Edison shall file with the Commission Advisory and Compliance Division and all parties to this proceeding a report on the operating results of its power sale agreement with SMUD. The report shall include, for each month from February through the end of 1990: energy delivered, peak demand, total revenue, CPUC jurisdictional revenue, and the split of that revenue into components for the ECAC balancing account, AER, incremental operations and maintenance expenses at 0.3 cents per kilowatt-hour, and credits to the ERAM balancing account.

This order is effective today.

Dated JAN 24 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Wesley Franklin

WESLEY FRANKLIN, Acting Executive Director

pb

APPENDIX A

List of Appearances

Applicant: Bruce A. Reed, Frank J. Cooley, Richard K. Durant, and Julie A. Miller, Attorney at Law, for Southern California Edison Company.

Interested Parties: Michael P. Alcantar, Attornoy at Law, for Messrs. Lindsay, Hart, Neil & Weigler; Richard Daish, Michael A. Ferguson, and Randolph Wu, Attorneys at Law, for El Paso Natural Gas Company; Messrs. Morrison & Foerster, by Jerry R. Bloom and Sarah M. Rockwell, Attorneys at Law, for California Cogeneration Council; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth and Evelyn Mc Cormish, for California Large Energy Consumers' Association; Matthew V. Brady, Attorney at Law, and Law Offices of Dian M. Grueneich, by Barry H. Epstein, Attorney at Law, for California Department of General Services; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Karen Edson, for KKE & Associates; Norman J. Furuta and Cynthia B. Hall, Attorneys at Law, for Department of the Navy; Paul J. Kaufman, for Cogenerators of Southern California; Thomas Knobloch, for Drazen Brubaker & Associates; William B. Marcus, for JBS Energy, Inc.; A. Kirk McKenzie, Attorney at Law, for California Energy Commission; Karen Norene Mills, Attorney at Law, for California Farm Bureau Federation; Donald G. Salow, for Association of California Water Agencies; Donald Schoenbeck, for RCS, Inc.; Michael P. Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization; Messrs. Downey, Brand, Seymour & Rohwen, by Philip A. Stohr, Attorney at Law, for Industrial Users; Nancy Thompson, for Barakat, Howard & Chamberlain; Robert B. Weisenmiller, for Morse, Richard, Weisenmiler & Associates; Harry K. Winters, for Regents, University of California; David B. Brearley, Attorney at Law, and Messrs. Goldberg, Fieldman & Latham, by Arnold Fieldman, Attorney at Law, for the City of Vernon; Leslie J. Girard, Attorney at Law, for the City of San Diego; Reed V. Schmidt, for California City-County Light Association; and Patrick J. Bittner, Attorney at Law, for himself.

Division of Ratepayer Advocates: Ira Kalinsky, Robert Cagen, and Hallie Yacknin, Attorneys at Law, and Bill Y. Lee.

Commission Advisory and Compliance Division: Paul Clanon and Karen Shea.

(END OF APPENDIX A)

JOINT RECOMMENDATION OF THE
DIVISION OF RATEPAYER ADVOCATES, SOUTHERN
CALIFORNIA EDISON, COGENERATORS OF SOUTHERN CALIFORNIA,
AND CALIFORNIA COGENERATION COUNCIL

Southern California Edison Company ("Edison"), the Division of Ratepayer Advocates ("DRA"), the Cogenerators of Southern California ("CSC"), and the California Cogeneration Council ("CCC") (collectively referred to herein as the parties) jointly recommend that the Commission adopt the following recommendations regarding revenue requirement change and Incremental Energy Rate ("IER") in this proceeding:

Total Revenue Requirement Change	($65.6 million)
Annual Average Incremental Energy Rate	9,586 BTU/KWh

Based upon the annual average incremental energy rate of 9,586 BTU/KWh reflected by this recommendation, the parties agree that the time differentiated IERs for the forecast period will be as follows:

	Peak	Mid	Off	Super Off-Peak
Summer	13,652	8,450	8,670	N/A
Winter	N/A	10,647	9,617	8,175

This recommendation is based upon DRA's prepared testimony and ELFIN simulations of the operation of Edison's system for the duration of the forecast period January 1, 1990 through December 31, 1990 as adjusted to reflect certain positions of the parties. The testimony of the parties supports a range of forecast revenue requirement and a range of incremental energy rates. However, the parties believe that adoption of this compromise position represents a reasonable recommendation based upon the positions advocated by the parties in this proceeding.

The parties jointly recommend that the Commission adopt these recommendations without any further ELFIN modelling simulations because this result is within a reasonable bandwidth of the expected values for revenue requirement change and IER.

The prepared testimony of CSC witness Donald W. Schoenbeck recommends, <u>inter alia</u>, a change in the current ratemaking treatment of Edison's off system sales revenues. As part of this joint exhibit, CSC shall not offer Mr. Schoenbeck's testimony (at pages 17-22 of the Prepared Testimony of Donald W. Schoenbeck and James A. Ross on behalf of the Cogenerators of Southern California) into evidence nor shall CSC argue in its briefs that the Commission adopt such a recommendation.

DRA and Edison agree to submit the issue regarding fuel oil inventory level ("FOIL") for resolution by the Commission. DRA and Edison agree that this issue will not affect the agreement regarding revenue requirement change.

The parties will not contest in this proceeding, either in hearings or in any other manner before this Commission, or in any other forum, the revenue requirement change and the IER recommendations contained in this exhibit. However, this shall not be construed to be acceptance of the methodology or assumptions underlying the parties' estimate of Edison's revenue requirement change or the Incremental Energy Rate or any of the resource assumptions utilized by DRA in its ELFIN simulation.

None of the principles or the methodologies underlying this joint exhibit shall be deemed by the Commission or any other entity as precedent in any proceeding or litigation except in order to implement in this proceeding the recommendations contained herein. The parties expressly reserve the right to advocate different principles and methodologies from those underlying this joint exhibit in other proceedings.

The parties understand and agree that this joint exhibit is subject to each and every condition set forth herein, including its acceptance by the Commission in its entirety and without change or condition. The parties agree to extend their best efforts to assure the adoption of these recommendations as the final revenue requirement change and IER for the forecast period.

(END OF APPENDIX B)

APPENDIX C

A.89-05-064 ALJ/RAB/CACO/akm/13 *

SOUTHERN CALIFORNIA EDISON COMPANY
CONSOLIDATION OF REVENUE REQUIREMENTS
Effective Date: February 1, 1990

REVENUE ELEMENT	PRESENT RATE REVENUE 1/ (000's of $)	REVENUE CHANGE (000's of $)	ADOPTED REVENUE REQUIREMENT 1/2/ (000's of $)	AVERAGE RATE 3/ (cents/Kwh)
Base rates				
Previously authorized rates	$3,616,252.6	(29,855.5)	3,586,397.1	5.324
Palo Verde 2	0.0	20,190.6	20,190.6	0.030 4/
Palo Verde 3	0.0	20,190.6	20,190.6	0.030 5/
Palo Verde 1	0.0	20,190.6	20,190.6	0.030 6/
Attrition for 1990	0.0	40,500.0	40,500.0	0.060 7/
Subtotal authorized base rate revenues	3,616,252.6	71,216.3	3,687,468.9	5.474
Major Additions Adjustment Clause (MAAC)				
SONGS 2 and 3 post-COO	44,456.5	(181.4)	44,275.1	0.066
Balsam Meadow	8,083.0	(33.0)	8,050.0	0.012
Devers-Valley-Serrano	3,367.9	(13.7)	3,354.2	0.005
High Voltage DC Transmission Line	11,450.9	(46.7)	11,404.2	0.017
SONGS pre-COO balancing account	8,083.0	(33.0)	8,050.0	0.012
Subtotal MAAC rate revenues	75,441.4	(307.9)	75,133.5	0.112
Energy Cost Adjustment Clause (ECAC)				
Fuel and purchased power (incl. FF&U)	2,549,877.8	(242,737.0)	2,307,140.8	3.425
Balancing account	117,877.1	155,467.3	273,344.4	0.406
LSFO writedown	54,560.3	(54,560.3)	0.0	0.000
Distillate writedown	4,715.1	(4,715.1)	0.0	0.000
Chevron settlement	208,137.3	(208,137.3)	0.0	0.000
Subtotal ECAC rate revenues	2,935,167.6	(354,682.4)	2,580,485.2	3.831
Annual Energy Rate	0.0	256,348.9	256,348.9	0.381
Electric Revenue Adjustment Billing Factor (ERABF)				
Regular ERABF	(204,769.4)	63,200.0	(141,569.4)	(0.210)
Palo Verde 1	0.0	51,923.2	51,923.2	0.077 8/
SMUD revenue (net non-fuel related) 11/	0.0	(29,955.0)	(29,955.0)	(0.044)
Subtotal ERABF rate revenues	(204,769.4)	85,168.2	(119,601.2)	(0.178)
Conservation Load Management Adjustment Clause	0.0	0.0	0.0	0.000
SUBTOTAL 9/	6,422,092.2	57,743.1	6,479,835.3	9.620
PERCENTAGE INCREASE		0.90%		
Low Income Ratepayer Assistance Program (LIRA)				
Low Income Discount Rate	0.0	(16,268.3)	(16,268.3)	(0.025)
Low Income Surcharge	0.0	18,139.3	18,139.3	0.028 10/
Subtotal LIRA Rate Net Revenues	0.0	1,871.0	1,871.0	0.003
SUBTOTAL	6,422,092.2	59,614.1	6,481,706.3	9.623
PERCENTAGE INCREASE		0.93%		
SMUD revenue (net non-fuel related) 11/	29,955.0	0.0	29,955.0	
Other operating revenue	57,547.0	0.0	57,547.0	
CPUC fees	8,086.6	0.0	8,086.6	0.012
TOTAL	6,487,725.7	59,614.1	6,547,339.9	

1/ Excludes Fringe and Sequoia
2/ Includes FF&U at 0.944% which translates to a factor of 1.00953
3/ Computed at an adjusted annual sales of 67,358.4 GWh which excludes employee discounts and are forecast for the period 1/1/90 - 12/31/90.
4/ Advice Letter 841-E, filed July 21, 1989
5/ Advice Letter 851-E, filed November 13, 1989
6/ Advice Letter 852-E, filed November 13, 1989
7/ Resolution E-3172, effective December 18, 1989
8/ Previously approved step increase to reflect recovery of deferred revenue, pursuant to D.86-10-023
9/ Revenue used for revenue allocation and rate design
10/ LIRA surcharge rate computed on adjusted sales of 65797.3 GWh, which excludes employee discounts and sales exempt from the surcharge pursuant to D.89-09-044
11/ Recorded SMUD revenue (non-fuel related) to be credited to ERAM balancing account

(END APPENDIX C)

A.89-05-064 ALJ/RAB *
CACD/akm/15

SOUTHERN CALIFORNIA EDISON COMPANY ECAC
ADOPTED REVENUE ALLOCATION 1/
Effective Date: February 1, 1990

								ADOPTED CHANGES (without LIRA)		ADOPTED CHANGES (with LIRA)		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV 3/ ($000's)	TOTAL MC REVS 4/ ($000's)	FULL EPMC ($000's)	(%) INC.	SAPC ($000's)	(%) INC.	2/3 EPMC 1/3 SAPC 2.5% CAP OVER SAPC 5/ ($000's)	(%) TOTAL INC.	2/3 EPMC 1/3 SAPC 2.5% CAP OVER SAPC 6/ ($000's)	(%) TOTAL INC.	AVERAGE RATE ($/KWH)
DOMESTIC	20,875	2,131,231	1,759,121	2,239,438	7.4	2,159,593	0.9	2,203,783	3.4	2,192,981	2.9	0.105
SM/MED POWER												
GS-1	4,428	527,983	397,839	520,437	(1.4)	532,758	0.9	529,494	0.3	530,715	0.5	0.120
GS-2	18,624	1,845,242	1,490,097	1,831,585	(0.7)	1,861,927	0.9	1,859,174	0.8	1,864,308	1.0	0.100
LARGE POWER												
TOU-8:2ND	7,725	688,084	509,910	667,044	(3.1)	694,306	0.9	682,428	(0.8)	684,558	(0.5)	0.089
TOU-8:PRI	7,990	632,126	463,201	605,941	(4.1)	637,842	0.9	622,265	(1.6)	624,461	(1.2)	0.078
TOU-8:SUB	5,203	322,664	234,937	307,335	(4.8)	325,582	0.9	316,295	(2.0)	317,723	(1.5)	0.061
AGRICULTURE	2,049	201,666	145,871	192,163	(4.7)	203,489	0.9	197,738	(1.9)	198,303	(1.7)	0.097
STREETLIGHTING	494	73,096	22,653	65,892	(9.9)	73,429	0.5	68,658	(6.1)	68,658	(6.1)	0.139
TOTAL	67,388	6,422,092	4,925,629	6,479,835	0.9	6,479,835	0.9	6,479,835	0.9	6,481,706	0.9	0.096

1/ Although facilities charges and optional TOU meter charges have been excluded from the revenue allocation process, these amounts have been added to the figures in this table in order to obtain the correct percentage increases and average rate calculations. Facilities charges and TOU meter charges are expressed in thousands for the following classes: $34.4 for GS-2; $32.6 for agriculture; $36,258.0 for streetlighting.
2/ ECAC sales figures have not been adjusted for employee discounts; fringe and Sequoia sales have been excluded.
3/ Present rate revenues are adjusted for the large power class to reflect the difference between actual interruptible credits and credits allocated on an EPMC basis.
4/ Based on marginal costs from SCE general rate case D.87-12-066. Marginal cost revenue responsibility has been updated for ECAC forecast sales, demand and customers, and adopted gas price.
5/ Interruptible credits are computed on an EPMC basis, based on D.87-12-066 as modified. Revenue deficiency from capping is spread to other classes on a 2/3 EPMC, 1/3 SAPC basis.
6/ Rate design based on Column h.

A.89-05-064 ALJ/RAB *
CACO/akm/2

SOUTHERN CALIFORNIA EDISON COMPANY
CALCULATION OF LOW INCOME RATEPAYER ASSISTANCE PROGRAM
BILLING FACTOR (LIRABF)

Line No.	Description	Baseline	Non-Baseline	Total
	LIRA Program Costs:			
	1990 Low Income Ratepayer Assistance Discount (cents/kwh):			
1	Domestic Rate (includes PUCRF) 1/	8.951	13.026	
2	PUCRF 1/	0.012	0.012	
3	Domestic Rate (Line 1 - Line 2)	8.939	13.014	
4	Low Income Discount Percent 2/	15%	15%	
5	Low Income Discount Rate (cents/kwh) (Line 3 * Line 4)	1.341	1.952	
6	Sales subject to Low Income Discount Rate (Mwh) 3/	587,909	429,533	1,017,442
7	Low Income Discount (000) (Line 5 * Line 6 / 100)	7,883.9	8,384.5	16,268.3
	ADMINISTRATIVE COSTS (000):			
8	Administrative Budget 4/			1,853.4
9	Plus FFEU 5/			17.7
10	Total Administrative Costs (000) (Line 8 + Line 9)			1,871.0 6/
11	Total LIRA Program Costs (Line 7 + Line 10)			18,139.3
	GWH SALES SUBJECT TO LIRABF			
12	Total Forecast Sales 7/			67,388.0
	Adjustments:			
13	DE Adjustment 8/			29.7
14	Sales Subject to LID Rate (Line 6)			1,017.4
15	Street Light Sales 9/			494.3
16	Special Contract Sales 10/			49.3
17	Total Adjustments			1,590.7
18	Total GWH Sales Subject to LIRABF			65,797.3
	CALCULATION OF THE LIRABF:			
19	Total LIRA Program Costs (000)			18,139.3
20	Total GWH Sales Subject to LIRABF			65,797.3
21	LIRABF (cents/kwh) ((Line 19/Line 20)/10)			0.028

1/ PUCRF is PUC Reimbursement Fee
2/ D.89-09-044, Ordering Paragraph No. 1
3/ D.89-09-044, Appendix A
4/ D.89-09-044, Appendix A
5/ FFEU Factor of 0.944% which translates to a factor of 1.00953
6/ Totals may not add due to rounding
7/ A.89-05-064, Exhibit 6, p. 41
8/ A.89-05-064, Exhibit 6, p. 41, 25% of DE Sales
9/ A.89-05-064, Exhibit 6, p. 41, Street Lighting Sales
10/ Pursuant to D.89-09-044

(END APPENDIX D)

A.89-05-064 ALJ/RAB*
CACD/akm/1

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY

RATE APPENDIX

- Residential Rates
- Small and Medium Power Rates
- Large Power Rates and Interruptible Rates
- Agricultural Rates
- Streetlighting Rates

Note: Rates in this appendix reflect the CPUC reimbursement fee of $.00012/kWh and the LIRA surcharge fee of $.00028/kWh for applicable rate schedules.

APPENDIX E PAGE 1

SOUTHERN CALIFORNIA EDISON COMPANY

RATE LEVEL SUMMARY

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE $/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	TIME-RELATED DEMAND CHARGE ($/kW) Winter	MAXIMUM DEMAND CHARGE ($/kW)	ENERGY CHARGE (¢/kWh) TOTAL RATES Summer	ENERGY CHARGE (¢/kWh) TOTAL RATES Winter
DOMESTIC: *	D:	0.10 1/						
	BL						8.979	8.979
	NBL						13.056	13.056
	TOU-D:	0.10 1/ 2/						
	ON						45.176	-
	MID						17.435	16.171
	OFF						7.349	7.349
	Baseline Credit *	6.075 ¢/kWh						
	D-LI:	0.10 1/						
	BL						7.810	7.810
	NBL						11.074	11.074
LIGHTING - SMALL & MEDIUM POWER:	GS-1P:	0.30					11.110	11.110
	GS-SP:	0.30					11.110	11.110
	GS-2:		33.45	9.25	2.90			
	1ST BLK (First 300 kWh/kW)						8.787	8.787
	2ND BLK						5.040	5.040
	TC-1	0.30					9.649	9.649
	TOU-GS:		33.45 3/					
	ON			12.55	-	2.90	12.579	-
	MID			1.95	0.00		10.109	11.356
	OFF			0.00	0.00		5.040	5.040
LARGE POWER: 4/	TOU-8-SEC:		272.85					
	ON			14.45	-	2.95	10.946	-
	MID			2.25	0.00		8.784	9.865
	OFF			0.00	0.00		5.040	5.040
	TOU-8-PRI:		272.15					
	ON			14.15	-	2.15	10.811	-
	MID			2.15	0.00		8.835	9.023
	OFF			0.00	0.00		5.040	5.040
	TOU-8-SUB:		262.00					
	ON			11.75	-	0.25	7.354	-
	MID			1.85	0.00		5.904	8.629
	OFF			0.00	0.00		5.040	5.040
AGRICULTURAL & PUMPING:	PA-1:		10.95	1.10 5/	1.10 5/		8.706	8.706
	PA-2:		21.85	7.80	1.25	-		
	1ST BLK (First 300 kWh/kW)						9.368	9.368
	2ND BLK						5.040	5.040
	TOU-ALMP-2:		10.95					
	ON						21.848	-
	MID						-	21.553
	OFF						7.077	7.569
	TOU-PA-1:		10.95	3.00 6/	3.00 6/			
	ON						9.773	-
	MID						-	9.533
	OFF						6.063	6.183
	TOU-PA (RATE A):		32.80 7/	1.10 5/	1.10 5/			
	ON						13.444	-
	MID						10.768	12.116
	OFF						5.040	5.040
	TOU-PA (RATE B):		32.80 7/			1.25		
	ON			6.55	-		13.512	-
	MID			0.00	0.00		10.842	12.177
	OFF			0.00	0.00		5.040	5.040
	TOU-PA-3 (RATE A):		32.80 7/	1.10 5/	1.10 5/			
	ON						13.576	-
	MID						10.991	12.345
	OFF						5.040	5.040
	TOU-PA-3 (RATE B):		32.80 7/			1.25		
	ON			6.55	-		14.622	-
	MID			0.00	0.00		11.839	13.295
	OFF			0.00	0.00		5.040	5.040
	TOU-PA-4 (RATE A):		32.80 7/	1.10	1.10			
	ON						13.541	-
	MID						10.954	12.316
	OFF						5.040	5.040
	TOU-PA-4 (RATE B):		32.80 7/			1.25		
	ON			6.55	-		14.564	-
	MID			0.00	0.00		11.792	13.244
	OFF			0.00	0.00		5.040	5.040
	TOU-PA-5 (>35KW MIN BILL): 7/					1.25		
	ON			6.55	-		8.379	-
	MID		21.85 8/	0.00	0.00		6.738	7.543
	OFF			0.00	0.00		6.198	6.242

1/ Minimum Charge
2/ Additional Meter charge at $0.15 /customer/day.
3/ Additional Meter charge at $7.00 /customer/month.
4/ Subject to Rate Limiters: Average Summer SEC 0.13212 PRI = 0.13212; Summer On-peak SEC 0.78160 PRI = 0.77003 SUB = 0.56343
5/ Connected load charge per Hp per month
6/ per kVA per month
7/ Additional Meter charge at $6.00 /customer/month.
8/ Summer Monthly Minimum Charge = $24.75 /kW of Contract Demand
Winter Monthly Minimum Charge = $10.50 /kW of Contract Demand

* Domestic Seasonal Schedule DS: Summer season premium = 7.000 ¢/kWh
Winter season discount = 7.000 ¢/kWh

Standby Schedule S : ($/Standby kW) SEC $2.95 PRI $2.15 SUB $0.25
RTP-2 Base Rate = 6.221 Cents/kWh

A.87-05-064 ALJ/RAB*
CACD/akn/2

SOUTHERN CALIFORNIA EDISON COMPANY
INTERRUPTIBLE POWER SCHEDULES
RATE LEVEL SUMMARY

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE c/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	TIME-RELATED DEMAND CHARGE ($/kW) Winter	MAXIMUM DEMAND CHARGE ($/kW)	ENERGY CHARGE (c/kWh) TOTAL RATES Summer	ENERGY CHARGE (c/kWh) TOTAL RATES Winter
	I-5-A SEC:	272.85						
LARGE POWER:	ON			14.45	-	2.95	9.446	-
	MID			2.25	0.00		7.284	8.365
	OFF			0.00	0.00		2.540	2.540
	I-5-A PRI:	272.15						
	ON			14.15	-	2.15	8.511	-
	MID			2.15	0.00		6.535	7.523
	OFF			0.00	0.00		2.540	2.540
	I-5-A SUB:	262.00						
	ON			11.75	-	0.25	5.854	-
	MID			1.85	0.00		4.404	5.129
	OFF			0.00	0.00		2.540	2.540
	I-5-B SEC:	272.85						
	ON			14.45	-	2.95	10.946	-
	MID			2.25	0.00		8.784	9.865
	OFF			0.00	0.00		5.040	5.040
	OFF						2.540	2.540
	I-5-B PRI:	272.15						
	ON			14.15	-	2.15	10.011	-
	MID			2.15	0.00		8.035	9.023
	OFF			0.00	0.00		5.040	5.040
	OFF						2.540	2.540
	I-5-B SUB:	262.00						
	ON			11.75	-	0.25	7.354	-
	MID			1.85	0.00		5.904	6.629
	OFF			0.00	0.00		5.040	5.040
	OFF						2.540	2.540
	I-6-A SEC:	272.85						
	ON			9.50	-	2.95	10.248	-
	MID			1.55	0.00		8.244	9.302
	OFF			0.00	0.00		4.582	4.566
	I-6-A PRI:	272.15						
	ON			9.75	-	2.15	9.328	-
	MID			1.45	0.00		7.505	8.486
	OFF			0.00	0.00		4.582	4.566
	I-6-A SUB:	262.00						
	ON			7.50	-	0.25	6.727	-
	MID			1.20	0.00		5.423	6.134
	OFF			0.00	0.00		4.582	4.566
	I-6-B SEC:	272.85						
	ON			10.45	-	2.95	10.335	-
	MID			1.65	0.00		8.311	9.372
	OFF			0.00	0.00		4.639	4.625
	I-6-B PRI:	272.15						
	ON			10.30	-	2.15	9.413	-
	MID			1.55	0.00		7.571	8.553
	OFF			0.00	0.00		4.639	4.625
	I-6-B SUB:	262.00						
	ON			8.05	-	0.25	6.805	-
	MID			1.25	0.00		5.482	6.195
	OFF			0.00	[illegible]		4.639	4.625

A.87-05-064 ALJ/RAB*
CACD/alm/3

SOUTHERN CALIFORNIA EDISON COMPANY
SUPER OFF-PEAK SCHEDULES
RATE LEVEL SUMMARY

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE ¢/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/KW) Summer	Spring/Fall	Winter	MAXIMUM DEMAND CHARGE ($/KW)	ENERGY CHARGE (¢/kWh) TOTAL RATES Summer	Spring/Fall	Winter
	TOU-GS-SOP:		1/							
LIGHTING - SMALL & MEDIUM POWER:	ON		33.45	36.80	-	-	2.90	10.352	-	-
	MID			1.00	0.50	0.50		10.352	7.852	8.610
	OFF			0.00	0.00	0.00		6.836	7.292	7.292
	OFF			0.00	0.00	0.00		3.540	3.540	3.540
	TOU-8-SOP-SEC:		272.85							
LARGE POWER:	ON			36.00	-	-	2.55	9.820	-	-
	MID			0.95	0.50	0.50		9.820	7.438	8.179
	OFF			0.00	0.00	0.00		6.476	6.908	6.908
	OFF			0.00	0.00	0.00		3.540	3.540	3.540
	TOU-8-SOP-PRI:		272.15							
	ON			35.90	-	-	2.15	8.641	-	-
	MID			0.95	0.50	0.50		8.641	6.563	7.214
	OFF			0.00	0.00	0.00		5.716	6.096	6.095
	OFF			0.00	0.00	0.00		3.540	3.540	3.540
	TOU-8-SOP-SUB:		262.00							
	ON			33.00	-	-	0.25	7.003	-	-
	MID			0.50	0.45	0.45		7.003	5.336	5.863
	OFF			0.00	0.00	0.00		4.647	4.957	4.957
	OFF			0.00	0.00	0.00		3.540	3.540	3.540
	TOU-8-SOP-I-A-SEC:		272.85							
	ON			25.20	-	-	2.95	9.474	-	-
	MID			0.60	0.35	0.35		9.474	7.218	7.955
	OFF			0.00	0.00	0.00		6.155	6.677	6.686
	OFF			0.00	0.00	0.00		3.383	3.383	3.383
	TOU-8-SOP-I-A-PRI:		272.15							
	ON			25.10	-	-	2.15	8.409	-	-
	MID			0.60	0.35	0.35		8.409	6.350	6.996
	OFF			0.00	0.00	0.00		5.506	5.872	5.881
	OFF			0.00	0.00	0.00		3.383	3.383	3.383
	TOU-8-SOP-I-A-SUB:		262.00							
	ON			22.65	-	-	0.25	6.773	-	-
	MID			0.60	0.30	0.30		6.773	5.132	5.655
	OFF			0.00	0.00	0.00		4.448	4.743	4.751
	OFF			0.00	0.00	0.00		3.383	3.383	3.383
	TOU-8-SOP-I-B-SEC:		272.85							
	ON			26.50	-	-	2.95	9.516	-	-
	MID			0.65	0.35	0.35		9.516	7.245	7.983
	OFF			0.00	0.00	0.00		6.202	6.705	6.713
	OFF			0.00	0.00	0.00		3.402	3.402	3.402
	TOU-8-SOP-I-B-PRI:		272.15							
	ON			26.40	-	-	2.15	8.430	-	-
	MID			0.65	0.35	0.35		8.430	6.376	7.023
	OFF			0.00	0.00	0.00		5.532	5.900	5.907
	OFF			0.00	0.00	0.00		3.402	3.402	3.402
	TOU-8-SOP-I-B-SUB:		262.00							
	ON			24.00	-	-	0.25	6.802	-	-
	MID			0.65	0.30	0.30		6.802	5.157	5.681
	OFF			0.00	0.00	0.00		4.473	4.770	4.777
	OFF			0.00	0.00	0.00		3.402	3.402	3.402
	TOU-PA-SOP:									
AGRICULTURAL & PUMPING:	ON		32.80 2/	35.05	-	-	1.25	9.374		-
	OFF			0.00	0.00	0.00		6.815		7.008
	OFF			0.00	0.00	[illegible].00		3.540		3.540

1/ Additional Meter charge $7.00 /customer/month.
2/ Additional Meter charge $6.00 /customer/month.

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

LS-1
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A - ALL NIGHT SERVICE 1990

WATTS	LUMENS	BASE ENERGY RATE (1)	OFFSET ENERGY RATE (2)	KWH PER MONTH (3)	BASE ENERGY CHG. (1 * 3) (4)	OFFSET ENERGY CHG. (2 * 3) (5)	NON-ENERGY CHARGE RATE (6)	TOTAL ($/LAMP-MO) (4+5+6) (7)
INCANDESCENT LAMPS								
103	1,000	0.02854	0.03389	35.535	1.01417	1.20428	6.24	8.46
202	2,500	0.02854	0.03389	69.690	1.98895	2.36179	6.24	10.59
327	4,000	0.02854	0.03389	112.815	3.21974	3.82330	6.25	13.29
448	6,000	0.02854	0.03389	154.560	4.41114	5.23804	6.10	15.85
MERCURY VAPOR LAMPS								
100	4,000	0.02854	0.03389	45.195	1.28987	1.53166	6.23	9.05
175	7,900	0.02854	0.03389	74.520	2.12680	2.52548	6.20	10.85
250	12,000	0.02854	0.03389	103.845	2.96374	3.51931	6.23	12.71
400	21,000	0.02854	0.03389	163.530	4.66715	5.54203	6.61	16.82
700	41,000	0.02854	0.03389	277.035	7.90658	9.38872	6.67	23.97
1,000	55,000	0.02854	0.03389	391.575	11.17555	13.27048	6.67	31.12
HIGH PRESSURE SODIUM								
50	4,000	0.02854	0.03389	20.010	0.57109	0.67814	6.23	7.48
70	5,800	0.02854	0.03389	28.635	0.81724	0.97044	6.20	7.99
100	9,500	0.02854	0.03389	40.365	1.15202	1.36797	6.20	8.72
150	16,000	0.02854	0.03389	66.585	1.90034	2.25657	6.24	10.40
200	22,000	0.02854	0.03389	84.870	2.42219	2.87624	6.60	11.90
[illegible]	27,500	0.02854	0.03389	107.985	3.08189	3.65961	6.62	13.36
[illegible]	50,000	0.02854	0.03389	167.315	4.77546	5.67064	6.70	17.15
LOW PRESSURE SODIUM								
35	4,800	0.02854	0.03389	21.735	0.62032	0.73660	6.77	8.13
55	8,000	0.02854	0.03389	28.980	0.82709	0.98213	6.77	8.53
90	13,500	0.02854	0.03389	45.195	1.28987	1.53166	7.70	10.52
135	22,500	0.02854	0.03389	62.790	1.79203	2.12795	7.97	11.89
180	33,000	0.02854	0.03389	79.005	2.25480	2.67748	7.72	12.65

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

LS-1
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B - MIDNIGHT SERVICE 1990

WATTS	LUMENS	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1)*(3)	OFFSET ENERGY CHG. (2)*(3)	NON-ENERGY CHARGE RATE	TOTAL ($/LAMP-MO) (4+5+6)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
INCANDESCENT LAMPS								
103	1,000	0.03559	0.03389	17.943	0.64397	0.60809	6.24	7.49
202	2,500	0.03589	0.03389	35.188	1.26290	1.19252	6.24	8.70
327	4,000	0.03589	0.03389	55.953	2.04440	1.93048	6.25	10.22
445	6,000	0.03589	0.03389	78.042	2.80093	2.64484	6.20	11.65
MERCURY VAPOR LAMPS								
100	4,000	0.03589	0.03389	22.820	0.81901	0.77337	6.23	7.82
175	7,900	0.03589	0.03389	37.627	1.35043	1.27518	6.20	8.83
250	12,000	0.03589	0.03339	52.434	1.88186	1.77699	6.23	9.89
400	21,000	0.03589	0.03339	82.571	2.96347	2.79833	6.61	12.37
700	41,000	0.03589	0.03389	139.883	5.02040	4.74063	6.67	16.43
1,000	55,000	0.03589	0.03389	197.717	7.09606	6.70063	6.67	20.47
HIGH PRESSURE SODIUM								
50	4,000	0.03589	0.03389	10.104	0.36263	0.34242	6.23	6.94
[illegible]	5,800	0.03539	0.03389	14.459	0.51893	0.49002	6.20	7.21
[illegible]	9,500	0.03589	0.03389	20.381	0.73147	0.69071	6.20	7.62
[illegible]	16,000	0.03589	0.03389	33.621	1.20666	1.13942	6.24	8.59
200	22,000	0.03589	0.03389	42.853	1.53799	1.45229	6.60	9.59
250	27,500	0.03539	0.03389	54.525	1.95690	1.84785	6.62	10.42
400	50,000	0.03589	0.03389	84.487	3.03224	2.86326	6.70	12.60
LOW PRESSURE SODIUM								
35	4,800	0.03559	0.03389	10.975	0.39389	0.37194	6.77	7.54
55	8,000	0.03589	0.03389	14.633	0.52518	0.49591	6.77	7.79
90	13,500	0.03589	0.03389	22.810	0.81901	0.77337	7.70	9.29
135	22,500	0.03559	0.03389	31.704	1.13786	1.07445	7.97	10.18
180	33,000	0.03589	0.03389	39.892	1.43172	1.35194	7.72	10.50

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

LS-2
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A - MULTIPLE SERVICE/ALL NIGHT 1990

WATTS	LUMENS	BASE ENERGY RATE (1)	OFFSET ENERGY RATE (2)	KWH PER MONTH (3)	BASE ENERGY CHG. (1 * 3) (4)	OFFSET ENERGY CHG. (2 * 3) (5)	NON-ENERGY CHARGE RATE (6)	TOTAL ($/LAMP-MO) (4+5+6) (7)
INCANDESCENT LAMPS								
103	1,000	0.02854	0.03389	35.535	1.01417	1.20428	0.79	3.01
202	2,500	0.02854	0.03389	69.699	1.98395	2.36179	0.79	5.14
327	4,000	0.02854	0.03389	112.815	3.21974	3.82330	0.79	7.83
445	6,000	0.02854	0.03389	154.560	4.41114	5.23804	0.79	10.44
690	10,000	0.02854	0.03389	238.050	6.79395	8.06751	0.79	15.65
MERCURY VAPOR LAMPS								
100	4,000	0.02854	0.03389	45.195	1.28987	1.53166	0.79	3.61
175	7,900	0.02854	0.03339	74.520	2.12680	2.52548	0.79	5.44
250	12,000	0.02854	0.03389	103.845	2.95374	3.51931	0.79	7.27
400	21,000	0.02854	0.03389	163.530	4.56715	5.54203	0.79	11.00
700	41,000	0.02854	0.03389	277.035	7.90658	9.38872	0.79	18.09
1,000	55,000	0.02854	0.03389	391.575	11.17555	13.27048	0.79	25.24
HIGH PRESSURE SODIUM								
50	4,000	0.02854	0.03389	20.010	0.57109	0.67814	0.79	2.04
70	5,800	0.02854	0.03389	25.635	0.81724	0.97044	0.79	2.53
[illegible]00	9,500	0.02854	0.03389	40.365	1.15202	1.36797	0.79	3.31
150	16,000	0.02854	0.03389	65.585	1.90034	2.25657	0.79	4.95
200	22,000	0.02854	0.03339	84.870	2.42219	2.87624	0.79	6.09
250	27,500	0.02854	0.03389	107.985	3.08189	3.65961	0.79	7.53
310	37,000	0.02854	0.03389	132.135	3.77113	4.47806	0.79	9.04
400	50,000	0.02854	0.03389	167.325	4.77546	5.67064	0.79	11.24
LOW PRESSURE SODIUM								
35	4,800	0.02854	0.03389	21.735	0.62032	0.73660	0.79	2.15
55	8,000	0.02854	0.03389	28.980	0.82709	0.98213	0.79	2.60
90	13,500	0.02854	0.03389	45.195	1.28987	1.53166	0.79	3.61
135	22,500	0.02854	0.03389	62.790	1.79203	2.12795	0.79	4.71
180	33,000	0.02854	0.03389	79.005	2.25480	2.67748	0.79	5.72

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

LS-1
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8 - MULTIPLE SERVICE/MIDNIGHT 1990

WATTS	LUMENS	BASE ENERGY RATE (1)	OFFSET ENERGY RATE (2)	KWH PER MONTH (3)	BASE ENERGY CHG. (1 * 3) (4)	OFFSET ENERGY CHG. (2 * 3) (5)	NON-ENERGY CHARGE RATE (6)	TOTAL ($/LAMP-MO) (4+5+6) (7)
INCANDESCENT LAMPS								
103	1,000	0.03589	0.03389	17.943	0.64397	0.60809	0.79	2.04
202	2,500	0.03589	0.03389	35.185	1.25290	1.19252	0.79	3.25
327	4,000	0.03589	0.03389	56.963	2.04440	1.93048	0.79	4.76
448	6,000	0.03589	0.03389	78.042	2.80093	2.64484	0.79	6.24
690	10,000	0.03589	0.03389	120.198	4.31391	4.07351	0.79	9.18
MERCURY VAPOR LAMPS								
100	4,000	0.03589	0.03389	22.820	0.81901	0.77337	0.79	2.38
175	7,900	0.03589	0.03389	37.627	1.35043	1.27518	0.79	3.42
250	12,000	0.03589	0.03389	52.434	1.88186	1.77699	0.79	4.45
400	21,000	0.03589	0.03389	82.571	2.96347	2.79833	0.79	6.55
700	41,000	0.03589	0.03389	139.883	5.02040	4.74063	0.79	10.55
1,000	55,000	0.03589	0.03389	197.717	7.09606	6.70063	0.79	14.59
HIGH PRESSURE SODIUM								
[illegible]0	4,000	0.03589	0.03389	10.104	0.36263	0.34242	0.79	1.50
[illegible]	5,800	0.03589	0.03389	14.459	0.51893	0.49002	0.79	1.80
[illegible]00	9,500	0.03589	0.03389	20.381	0.73147	0.69071	0.79	2.21
150	16,000	0.03589	0.03389	33.621	1.20665	1.13942	0.79	3.14
200	22,000	0.03589	0.03389	42.853	1.53799	1.45229	0.79	3.78
250	27,500	0.03589	0.03389	54.525	1.95690	1.84785	0.79	4.59
310	37,000	0.03589	0.03389	66.719	2.39454	2.26111	0.79	5.45
400	50,000	0.03589	0.03389	84.487	3.03224	2.86326	0.79	6.69
LOW PRESSURE SODIUM								
35	4,800	0.03589	0.03389	10.975	0.39389	0.37194	0.79	1.56
55	8,000	0.03589	0.03389	14.633	0.52518	0.49591	0.79	1.81
90	13,500	0.03589	0.03389	22.820	0.81901	0.77337	0.79	2.38
135	22,500	0.03589	0.03389	31.704	1.13786	1.07445	0.79	3.00
180	33,000	0.03589	0.03389	39.892	1.43172	1.35194	0.79	3.57

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

LS-2
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C - SERIES SERVICE/ALL NIGHT 1990

WATTS	LUMENS	BASE ENERGY RATE (1)	OFFSET ENERGY RATE (2)	KWH PER MONTH (3)	BASE ENERGY CHG. (1 * 3) (4)	OFFSET ENERGY CHG. (2 * 3) (5)	NON-ENERGY CHARGE RATE (6)	TOTAL ($/LAMP-MO) (4+5+6) (7)
INCANDESCENT LAMPS								
103	1,000	0.02854	0.03389	29.528	0.84273	1.00070	3.55	5.39
202	2,500	0.02854	0.03389	64.557	1.84274	2.18813	3.55	7.58
327	4,000	0.02854	0.03389	97.538	2.78659	3.30895	3.55	9.65
448	6,000	0.02854	0.03389	136.514	3.89896	4.62985	3.55	12.08
690	10,000	0.02854	0.03389	227.559	6.49453	7.71197	3.55	17.76
MERCURY VAPOR LAMPS								
100	4,000	0.02854	0.03389	51.675	1.47480	1.75127	3.55	6.78
175	7,900	0.02854	0.03389	85.574	2.44228	2.90010	3.55	8.89
250	12,000	0.02854	0.03389	117.819	3.36255	3.99289	3.55	10.91
400	21,000	0.02854	0.03389	183.963	5.25030	6.23451	3.55	15.03
700	41,000	0.02854	0.03389	314.184	8.96681	10.64770	3.55	23.16
1,000	55,000	0.02854	0.03389	442.333	12.62433	14.99053	3.55	31.17
HIGH PRESSURE SODIUM								
50	4,000	0.02854	0.03389	30.745	0.87749	1.04198	3.55	5.47
[illegible]	5,800	0.02854	0.03389	40.834	1.16540	1.38386	3.55	6.10
[illegible]	9,500	0.02854	0.03389	58.128	1.65897	1.96996	3.55	7.18
150	16,000	0.02854	0.03389	83.590	2.38566	2.83287	3.55	8.77
200	22,000	0.02854	0.03389	111.933	3.19457	3.79341	3.55	10.54
LOW PRESSURE SODIUM								
35	4,800	0.02854	0.03389	24.225	0.69138	0.82099	3.55	5.06
55	8,000	0.02854	0.03389	34.200	0.97607	1.15904	3.55	5.69
90	13,500	0.02854	0.03389	61.750	1.76235	2.09271	3.55	7.41
135	22,500	0.02854	0.03389	87.875	2.50795	2.97808	3.55	9.04
180	33,000	0.02854	0.03389	104.025	2.96887	3.52541	3.55	10.04

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

LS-2

O - SERIES SERVICE/MIDNIGHT 1990

WATTS	LUMENS	BASE ENERGY RATE	OFFSET ENERGY RATE	*KWH PER MONTH	BASE ENERGY CHG. (1 * 3)	OFFSET ENERGY CHG. (2 * 3)	NON-ENERGY CHARGE RATE	TOTAL ($/LAMP-MO) (4+5+6)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
INCANDESCENT LAMPS								
103	1,000	0.03589	0.03389	14.918	0.53541	0.50557	3.55	4.59
202	2,500	0.03589	0.03389	32.620	1.17073	1.10549	3.55	5.83
327	4,000	0.03589	0.03389	49.327	1.77035	1.67169	3.55	6.99
448	6,000	0.03589	0.03389	69.018	2.47706	2.33902	3.55	8.37
690	10,000	0.03589	0.03389	114.964	4.12606	3.89613	3.55	11.57
MERCURY VAPOR LAMPS								
100	4,000	0.03589	0.03389	26.113	0.93720	0.88497	3.55	5.37
175	7,900	0.03589	0.03389	43.242	1.55196	1.46547	3.55	6.57
250	12,000	0.03589	0.03389	59.537	2.13678	2.01771	3.55	7.70
400	21,000	0.03589	0.03389	92.961	3.33637	3.15045	3.55	10.04
700	41,000	0.03589	0.03389	158.764	5.69804	5.38051	3.55	14.63
1,000	55,000	0.03589	0.03389	223.523	8.02224	7.57519	3.55	19.15
HI[illegible]ESSURE SODIUM								
[illegible]	4,000	0.03589	0.03389	15.539	0.55769	0.52662	3.55	4.63
70	5,800	0.03589	0.03389	20.638	0.74070	0.69942	3.55	4.99
100	9,500	0.03589	0.03389	29.379	1.05441	0.99565	3.55	5.60
150	16,000	0.03589	0.03389	42.247	1.51624	1.43175	3.55	6.50
200	22,000	0.03589	0.03389	56.572	2.03037	1.91723	3.55	7.50
LOW PRESSURE SODIUM								
35	4,800	0.03589	0.03389	12.240	0.43929	0.41481	3.55	4.40
55	8,000	0.03589	0.03389	17.280	0.62018	0.58562	3.55	4.76
90	13,500	0.03589	0.03389	31.200	1.11977	1.05737	3.55	5.73
135	22,500	0.03589	0.03389	44.400	1.59352	1.50472	3.55	6.65
180	33,000	0.03589	0.03389	52.560	1.88638	1.78126	3.55	7.22

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

LS-3 1990

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH ANNUAL CWH	BASE ENERGY CHG. (1 * 3)	OFFSET ENERGY CHG. (2 * 3)	CUSTOMER CHARGE RATE
	(1)	(2)				
TOTAL ENERGY	0.02554	0.03389	41.7	1,190,118	1,413,213	
CUSTOMER CHARGE						
MULTIPLE	0.00000	0.00000	0			8.52
SERIES	0.00000	0.00000	0			105.75

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

CWL 1990

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1 * 3)	OFFSET ENERGY CHG. (2 * 3)	NON-ENERGY CHARGE RATE	TOTAL ($/LAMP-MO) (4+5+6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
RATE A	0.02854	0.03389	32.341	0.92301	1.09504	6.55	8.57
RATE B	0.02854	0.03389	32.341	0.92301	1.09604	2.15	4.17
RATE C	0.00000	0.00000	0.000	0.00000	0.00000	0.40	0.40

RATES EFFECTIVE FEBRUARY 1, 1990 SOUTHERN CALIFORNIA EDISON COMPANY

OL-1 1990 ALL NIGHT SERVICE

WATTS	LUMENS	BASE ENERGY RATE (1)	OFFSET ENERGY RATE (2)	KWH PER MONTH (3)	BASE ENERGY CHG. (1 * 3) (4)	OFFSET ENERGY CHG. (2 * 3) (5)	NON-ENERGY CHARGE RATE (6)	TOTAL ($/LAMP-MO) (4+5+6) (7)
MERCURY VAPOR LAMPS								
175	7,900	0.02854	0.03389	74.520	2.12680	2.52543	5.09	9.74
400	21,000	0.02854	0.03389	168.460	4.80785	5.70911	5.50	16.02
HIGH PRESSURE SODIUM								
70	5,800	0.02854	0.03389	28.635	0.81724	0.97044	5.09	6.88
100	9,500	0.02854	0.03389	40.365	1.15202	1.36797	5.09	7.61
200	22,000	0.02854	0.03389	84.870	2.42219	2.87624	5.49	10.79

MIDNIGHT SERVICE

WATTS	LUMENS	BASE ENERGY RATE (1)	OFFSET ENERGY RATE (2)	KWH PER MONTH (3)	BASE ENERGY CHG. (1 * 3) (4)	OFFSET ENERGY CHG. (2 * 3) (5)	NON-ENERGY CHARGE RATE (6)	TOTAL ($/LAMP-MO) (4+5+6) (7)
[illegible]RY VAPOR LAMPS								
175	7,900	0.03589	0.03389	37.627	1.35043	1.27518	5.09	7.72
400	21,000	0.03589	0.03389	82.571	2.96347	2.79833	5.50	11.26
HIGH PRESSURE SODIUM								
70	5,800	0.03589	0.03389	14.459	0.51893	0.49002	5.09	6.10
100	9,500	0.03589	0.03389	20.381	0.73147	0.69071	5.09	6.51
200	22,000	0.03589	0.03389	42.853	1.53799	1.45229	5.49	8.48

OL-1 POLE CHARGE

STANDARD POLES 2.20

(END APPENDIX E)