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Decision 90-12-067 December 19, 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, its Electric Revenue Adjustment Billing Factor and its Low Income Ratepayer Assistance Surcharge effective January 1, 1991; (2) Authority to Revise the Incremental Energy Rate, the Energy Reliability Index and Avoided Capacity Cost Pricing; and (3) Review of the Reasonableness of Edison's Operations during the period from April 1, 1989, through March 31, 1990.	Application 90-06-001 (Filed June 1, 1990)

(See Appendix A for appearances.)

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I N D E X

INTERIM OPINION

I. Summary of Decision

This order authorizes Southern California Edison Company (Edison) an increase of $458.7 million or 6.7% in Energy Cost Adjustment Clause (ECAC) related revenues. The components of this amount are as follows:

	Millions of Dollars
Energy Cost Adjustment Billing Factor (ECABF)	$288.8
Electric Revenue Adjustment Billing Factor (ERABF)	182.0
Palo Verde 2 (ERABF)	(2.5)
Major Additions Adjustment Billing Factor (MAABF)	(15.8)
Low Income Surcharge (LIS)	6.2
Total	458.7

The $458.7 million increase in annual revenues is largely necessary to offset expected increases in fuel and purchased power costs for 1991.

Additionally, this order reflects revenue changes associated with other applications before the Commission in separate proceedings, as follows:[1]

Proceeding Number	Proceeding	Millions of Dollars
A.90-03-048	1991 Modified Attrition	0
A.L. No. 889-E	1991 Modified Attrition (Payroll Tax Adjustment)	1.7
A.90-04-036 A.L. Nos. 879-E and 885-E	Demand Side Management	4.0
A.90-05-016 A.L. No. 890-E	1991 Annual Cost of Capital	1.1
A.L. No. 873-E-A	Palo Verde 2 (Base)	(1.7)
A.L. No. 886-E	Intervenor Compensation	0.1
	Total	5.2

Accordingly, for purposes of revenue allocation and rate design, when the $5.2 million of increased revenues resulting from other proceedings is added to the $458.7 million increase authorized by this decision, the total increase is $463.9 million.

1 The revenue increases set forth on the above table differs slightly from those submitted in this proceeding due to revised present rate levels. The revised present rate levels became effective September 19, 1990 and resulted in changes in the present rate revenue. The tables in Appendix C show the revenue requirements for each of the proceedings; the present rate revenues resulting from September 19, 1990 rate levels and the resulting revenue changes.

On this basis, the revenue increases to the various rate groups are expected to be as follows:

Rate Group	Change From Present Rate Revenues With Low Income Ratepayer Assistance (LIRA) ($M)	(%)
Domestic	230.2	9.3%
Lighting - SMP:		
GS-SP/TP	26.6	5.0%
GS-2	144.3	7.2%
Total	170.9	6.7%
Large Power:		
TOU-8-SEC	29.9	4.2%
TOU-8-PRI	13.6	2.8%
TOU-8-SUB	25.2	5.6%
Total	68.7	4.2%
AG & Pumping:	6.8	3.4%
Subtotal	466.6	6.9%
St & Area Lgt	(2.7)	(3.9)%
Revenue Requirement Change with LIRA	463.9	6.8%

The above increase in annual revenues will become effective on January 1, 1991.

While the increase to the residential class as a whole is 9.3%, the increase in residential customer bills for usage at or below baseline quantities will be 11.5%. In the past, customer bills at or below baseline usage have been subsidized by customers in the residential class that have usage above baseline quantities. The Commission believes that customer bills should reflect their true cost of service. Accordingly, residential customer bills at or below baseline quantities will be increased 11.8%.

The Commission also adopted a minimum bill of 8.5 cents per day for the Low Income Domestic rate which gives these customers a 15% discount compared to what these customers would otherwise pay under the domestic rate.

For purposes of determining payments to Qualifying Facilities (QF), the Commission has adopted an Incremental Energy Rate (IER) of 9,531 Btu/kilowatt-hour (kWh) for the forecast period.

This proceeding remains open for consideration of reasonableness issues related to fuel and purchased power costs for the review period.

II. Summary of the Application

On June 1, 1990, Edison filed this application in which it requested an annual revenue increase of $479 million or 7.1%, effective January 1, 1991. Edison also requested that the revenue requirements which will be adopted by the Commission in several other pending applications be combined into one rate change effective January 1, 1991.

Edison states that the proposed rate changes were calculated in accordance with the revenue allocation and rate design parameters established in Edison's Test Year 1988 general rate case decisions (Decision (D.) 87-12-066 and D.88-09-031).

Also, Edison requested that the Commission find that:

a. Edison's fuel and energy-related costs recorded in the ECAC balancing account from April 1, 1989 through March 31, 1990, were reasonable; and

b. The incentive amounts, calculated pursuant to the Nuclear Unit Incentive Procedure, are reasonable.

These items are deferred to a separate phase of this proceeding.

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

a. An IER of 9,194 Btu/kWh for the ECAC forecast period, time-differentiated; and

b. An annual avoided capacity cost price of $0/kW, time-differentiated and based on:

1. Retention of the current ERI of 0.0; and

2. A change in the current annualized combustion turbine proxy capacity cost from $75.25/kW to $77.80/kW, using a recorded Gross National Product (GNP) deflator.

These issues are addressed in this phase of the proceeding.

In addition, Edison requested that the Commission find reasonable the expenses recorded in the ECAC balancing account for the period from April 1, 1989 through March 31, 1990. This item is deferred to a separate phase of this proceeding and will be the subject of a separate decision.

Edison contends that the requested revenue requirement increase is needed primarily to offset forecast increases for 1991 in the expense related to power purchases from nonutility power producers under the Public Utility Regulatory Policies Act of 1978 (PURPA). According to Edison, since 1983 purchases from QFs have steadily increased as a cost component influencing ECAC rates. PURPA purchases in 1983 amounted to 0.6% of deliveries. For 1991, Edison expects that PURPA purchases will amount to 30.5% of deliveries.

Although the principal cause of the requested revenue increase is the substantial increase in purchases from PURPA nonutility power producers, Edison asserts that increases in oil and gas expenses also contribute to the increase. According to

Edison, the increases in oil and gas expenses are due, in part, to rising natural gas prices and the anticipated curtailment of gas supplies to Edison by the Southern California Gas Company (SoCal).

III. Background

A. Electric Utility Offset Proceedings

The ECAC process allows electric rates to reflect changes in fuel and purchase power expenses on an annual basis outside of the utility's three-year general rate case cycle. This ECAC filing was made in accordance with the rate case plan for processing energy cost offset proceedings that was most recently modified by D.89-01-040. Under the rate case plan, staggered forecast periods are designated for the major electric utilities. Edison's forecast period is the 12-month period which begins on January 1 of each year, and rates reflecting ECAC, Annual Energy Rate (AER), and Electric Revenue Adjustment Mechanism (ERAM) revenue requirements are adjusted as of the January 1 revision date. The rate case plan provides for automatic suspension of the AER mechanism when the forecast period upon which the then-current AER was calculated ends and a new AER has not yet been adopted. Additionally, the Commission in Order Instituting Investigation (I.) 90-08-006 suspended the AER for all jurisdictional utilities on August 8, 1990.

By D.89-07-062 and D.89-09-044, which completed implementation of the baseline reform legislation known as Senate Bill (SB) 987 (Ch. 212, Stats. 1988), the Commission ordered energy utilities to give qualifying low income ratepayers a 15% discount on their energy bills. The costs of this LIRA program are collected through a surcharge which is accorded balancing account treatment and the LIRA surcharge is updated in the company's ECAC proceedings.

Consistent with previous ECAC proceedings, this application combines consideration of ECAC issues with an updating of key components of the calculation of prices paid for power sold to the utility by QFs. The QF calculation issues relate to the prices to be paid to QFs that do not have contracts specifying fixed prices. Variable QF prices are the sum of three basic components: a payment for capacity, a payment for the Operation and Maintenance (O&M) costs that the utility avoids because of its purchases from variably priced QFs, and a variable payment for energy.

Critical to the determination of these payments are the utility's ERI and IER.

The ERI is used to adjust the value of a generic combustion turbine, which we have used as a proxy for a utility's avoided capacity costs and which therefore forms the basis for capacity payments to QFs. An ERI of less than 1.0 indicates that the utility is in an excess capacity situation in that it has more than enough resources to maintain reliability.

The IER, which reflects the utility system's incremental efficiency in converting heat energy to electricity, is combined with an estimate of avoided O&M costs to form an equivalent IER which is multiplied by the utility's incremental fuel cost to produce the price the utility pays for the variably priced QFs' energy.

There is a logical relationship between conventional ECAC issues and the bases for QF prices. The forecast used to develop a utility's ECAC revenue requirement is derived from the estimated production and expense levels related to hydroelectric, nuclear, purchased power, alternative and renewable power, and oil- and gas-fired resources. The forecasts of energy production and availability affect the determination of the utility's generating efficiency at the margin as measured by the IER. Similarly, the expected availability of resources to meet forecast demand is reflected in the ERI.

Computerized production cost models designed to simulate the manner in which utility resources meet system loads are used to forecast energy costs which underlie ECAC revenue requirement calculations as well as ERI and IER values. The simulations are driven by resource and load assumptions which are inputs to the model and which, in many cases, represent the resolutions of conventional ECAC issues that constitute the heart of an ECAC proceeding.

The use of these models introduces another set of issues concerning how the modeler and the model translate and simplify the complexities of the utility system into terms that the model can understand, and what manipulations the model makes of this information. This category of issues is referred to as the modeling conventions.

The Commission directed that workshops be held in ECAC filings to determine resource and load data and other data that the utility used to calculate its IER. (D.87-12-066, p. 205.) The workshop is also to serve as a forum for the parties to agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The requirement for a common data set modeling workshop was integrated into the rate case plan by D.89-01-040, with a provision that the workshop should occur early in the proceeding. Accordingly, a production cost modeling workshop was held by the Commission Advisory and Compliance Division (CACD).

B. **Procedural Background**

Edison originally requested rates resulting in a revenue increase of $479 million on an annual basis for service rendered on and after January 1, 1991, comprised of the following components:

	Millions of Dollars
ECABF	284.2
AER	35.6
ERABF	168.7
MAABF	(15.7)
LIS	6.2
Total	479.0

On June 25, 1990, the California Large Energy Consumers Association (CLECA) filed a motion requesting that Edison be required to update all marginal unit cost elements for purposes of revenue allocation and rate design in this proceeding. On August 7, 1990, the assigned administrative law judge (ALJ) ruled that Edison should update its marginal unit customer and demand charges using the GNP Implicit Price Deflator. The ALJ also ruled that marginal cost IERs should not be updated for revenue allocation purposes but that the avoided cost IERs used for QF pricing shall be revised.

On August 8, 1990, the Division of Ratepayer Advocates (DRA) presented testimony in support of an overall ECAC revenue increase of $300.7 million. On August 21, 1990, Toward Utility Rate Normalization (TURN) moved to strike portions of the prepared testimony of DRA and Edison with respect to DRA's and Edison's proposals to reduce the nonbaseline to baseline rate ratio. Both DRA and Edison filed responses in opposition to TURN's motion. On September 6, 1990, the ALJ denied TURN's motion, indicating that the reduction in the nonbaseline to baseline ratio is a matter that the Commission should decide.

On August 10, 1990, Edison updated its testimony to reflect the ALJ's August 7 ruling. The updated testimony also reflected a proposed settlement in A.90-03-048 (the 1991 Modified Attrition Proceeding) and minor changes and corrections to its original testimony. As a result, Edison requested a revenue increase in this proceeding of $494.5 million which, when combined with Edison's requests in A.89-10-001, A.90-03-048, A.90-04-036, A.90-05-016, A.90-06-002, resulted in a combined January 1, 1991 revenue increase of $621 million.

On August 29, 1990, the Cogenerators of Southern California (CSC) recommended a revenue increase of $465.6 million if Edison's natural gas price forecast was adopted and $302.7 million if DRA's gas price forecast was adopted.

On September 10, 1990, Edison moved to strike a portion of DRA's testimony relating to a proposed change in methodology in the calculation of marginal energy costs. On September 12, 1990, the ALJ granted Edison's motion.

Hearings began September 10, 1990 and concluded on September 20, 1990 in San Francisco. Public hearings were held in Los Angeles on September 24, 1990 and statements of four residential customers were taken at that time. These customers expressed concern regarding the amount of the requested increase, and the impact on customers that manage on baseline quantities of energy.

While hearings were in progress, DRA made a compromise proposal. After discussion among Edison, DRA, CSC, and the California Cogeneration Council (CCC), a joint recommendation was executed. As indicated in Exhibit 34, the "Joint Recommendation of Southern California Edison Company, Division of Ratepayer Advocates, California Cogeneration Council, and Cogenerators of Southern California", Edison and the other signatories to Exhibit 34 recommend an ECABF revenue increase of $287.5 million and an IER of 9,531 Btu/kWh.

Opening briefs were filed on October 5, 1990. Reply briefs were filed on October 19, 1990. Briefs were received from

Edison, DRA, California City-County Street Light Association (CAL/SLA), California Manufacturers Association (CMA), CCC, CLECA, CSC, Geothermal Resources Association and Independent Energy Producers Association (GRA/IEP), Industrial Users, and TURN.

IV. <u>Summary and Quantification of Issues</u>

The following sections summarize the uncontested and contested issues in this proceeding.

A. <u>Uncontested Issues</u>

1. <u>Modeling Issues</u>

DRA used the Electric Utility Financial and Production Simulation Model - Version 1.83 (ELFIN) to develop its resource mix for the forecast period and used the output to develop the IER as specified in D.88-03-079. Although Edison filed a "base case" using the ELFIN model as required by D.87-12-066, Edison used the Westinghouse Electric Corporation's WESPRIDE Program - Version 3.1 (WESPRIDE) for its determination of the revenue requirement and the associated IER. The difference between ELFIN and WESPRIDE is that ELFIN is a load duration model while WESPRIDE is a chronological model.

In prior ECAC proceedings modeling issues have been the subject of extensive discussion. However, in this proceeding there were no modeling issues largely because of the joint agreement which is discussed later.

2. <u>Rate Design</u>

a. <u>Class Equal Percent Change</u>

The rate design procedures used by Edison in this proceeding are in accordance with the Class Equal Percent Change (CEPC) methodology previously adopted for Edison by the Commission. Edison proposes to design the customer, demand, and energy charges in accordance with the CEPC rate design methodology adopted in Edison's last general rate case (D.87-12-066) for use in ECAC proceedings. No party opposed the recommendation. We agree that the CEPC methodology should be continued.

b. Rate Limiter Phase-Out

Edison proposes to begin to phase out rate limiters by increasing the average and on-peak rate limiters effective January 1, 1991 over what otherwise would have been effective on that date. Edison believes that phasing out rate limiters is consistent with prior Commission decisions. No party opposed Edison's methodology for phasing out average and on-peak rate limiters. We agree that rate limiters should be phased out.

c. LIRA Minimum Charge

DRA proposed a minimum bill charge of 8.5 cents per day for the Low Income Domestic rate. Edison does not oppose DRA's proposal that the minimum bill charge on Rate Schedule No. D-LI (Domestic Low Income) be reduced from 10 cents to 8.5 cents per day. DRA's intent is to give the low income domestic customers a 15% discount from what such customers would otherwise pay under the domestic rate. DRA agreed that Tariff Schedule No. D-LI should be changed to reflect that intent. In order to implement the change, Edison's Tariff Schedule No. D-LI should be revised accordingly.

To implement the proposal, Edison requests that the Commission include an ordering paragraph in its decision with the following language to be substituted where appropriate in the tariff:

> Minimum Charge:
>
> "The Base Rate Energy Charge shall be subject to a daily Minimum Charge of $0.085 per single-family accommodation. In determining when the Base Rate Minimum Charge is applicable, the number of kilowatthours used is multiplied by 85 percent of an Annualized Base Rate of...."

The above change to the D-LI tariff will ensure that each D-LI customer receives a 15% discount from the domestic tariff. We agree that this change is appropriate. The proposed minimum bill charge of 8.5 cents per day should be adopted.

d. Time-of-Use Rate Schedules

To establish the total energy rates by time-of-use period and season, in accordance with the CEPC procedure adopted for Edison, Edison proposes to set the off-peak energy charges and second-block energy charges at 5 cents per kWh (excluding the Low Income Rate Assistance Surcharge and the Public Utilities Commission Reimbursement Fee) with the on- and mid-peak energy rates set to collect the remaining revenue requirement (after the customer and demand charges have been set) and to reflect the marginal energy cost ratios adopted in this proceeding. This proposal is unopposed and consistent with Edison's last general rate case and last two annual ECAC proceedings. We agree that this proposal should be adopted.

3. Determination of QF Payments

Edison, DRA, CSC, and CCC agreed in the joint recommendation (Exhibit 34) that for the determination of QF payments, particularly through avoided cost postings, Edison shall determine gas transportation costs using the gas volume adopted by the Commission in the most recent SoCal Annual Cost Allocation Proceeding beginning with A.90-03-018. Moreover, the parties to Exhibit 34 recommend that the Commission adopt the principle that Edison's QF payments be determined using the gas transportation costs based on the gas volumes adopted by the Commission in the SoCal Annual Cost Allocation Proceeding decision in effect on the first day of each QF payment period. We will adopt this recommendation.

4. **IER**

The following reflects the IER and ECAC revenue proposals of the parties:[2]

	Proposed IER Btu/kWh	Proposed ECAC Revenue Increase ($ million)
Edison	9,347	321.3
DRA	9,345	175.6
CCC	9,662/9,515	Not available
CSC	9,666/9,792	155.2/306.4

In 1978, the federal government enacted the PURPA, which required electric utilities to interconnect QFs to their grid and purchase all energy based on avoided cost pricing. During the forecast period, January-December 1991, Edison expects to purchase 24,782 gigawatt-hours (gWh) of energy from QFs with 4,567 megawatts (MW) of dedicated capacity (approximately 3,476 MW of effective capacity). The energy and capacity expense from these QFs is expected to be $1,330.9 million and $571.3 million, respectively. The total amount of payments to QFs during the forecast period is projected to be $1,902.3 million. QF energy is expected to supply 30% of Edison's total generation and purchases of energy.

In simple terms 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.[3] The intent is that the ratepayers be indifferent to whether the extra kilowatt hour of electricity is produced by the QF or the

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2 See Appendix B, page 6 for explanatory footnotes.

3 See D.88-03-079, p. 21; CPUC, 2nd, Vol. 27, p. 571 for a technical discussion on energy pricing for QFs.

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. If the IER is set too low, the QFs are paid less than a fair price for their energy.

The IER set in Edison's 1989 ECAC decision (D.90-01-048) was 9,586 Btu/kWh. In this application Edison asserts that 9,347 Btu/kWh is reasonable; DRA proposes 9,345 Btu/kWh; CCC (an organization representing QFs) proposes an IER of 9,515 Btu/kWh when gas is incremental and 9,662 Btu/kWh when oil is incremental. CSC (another QF organization) presented two IERs, one based on Edison's forecast assumptions and one based on DRA's. CSC's Edison case IER was 9,792 Btu/kWh, and their DRA case IER was 9,696 Btu/kWh.

The issue of the IER is very important to Edison's ratepayers because QF payments now represent a large, growing portion of Edison's total resource mix. QF purchases 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 are equal to the IER times the utility avoided gas or oil prices. The difference between Edison's position of 9,347 and CSC's Edison case IER of 9,792 Btu/kWh represents approximately $15 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 offered considerable testimony based upon complex computer forecasts to support their proposed IERs. Their testimony supports a range of forecast revenue requirement and a range of incremental energy rates. During the course of the hearings the parties discussed compromising their differences and making a joint recommendation to the Commission. Those discussions resulted in Exhibit 34 (attached as Appendix B), their recommendation that the Commission adopt an average annual IER of 9,531 Btu/kWh and a total revenue requirement increase of 287.5 million. The time-differentiated IERs for the forecast period are recommended to be:

	Peak	Mid	Off	Super Off-Peak
Summer	13,574	8,402	8,620	N/A
Winter	N/A	10,586	9,562	8,128

We find that the recommendations set forth in the joint recommendation (Exhibit 34) are within a reasonable zone of the expected values for revenue requirement change and IER. The joint recommendation of an annual average avoided cost IER of 9,531 Btu/kWh and the related time-differentiated avoided cost IER's is 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.

B. Contested Issues

1. ERI

a. Background

The ERI is a factor used in the calculation of as-available capacity payments to certain QFs. And it is a way of expressing whether the value of additional capacity on an electric utility system in a given year is the same as, or greater or less than, the utility's marginal capacity investment, which is assumed to be a combustion turbine. Out of the approximately 20,432 MW of total Edison area generation capacity, there are approximately 62 MW of QF capacity that are subject to the ERI.

Both DRA and Edison recommend that the ERI for the forecast period should be zero and the corresponding capacity price should be $0.00. GRA/IEP recommends that the Commission adopt an ERI of 1.0 and that a floor value of 0.4 be established. CCC concurs with the position taken by GRA/IEP in this proceeding.

Edison and DRA both used the reserve margin approximation method for calculation of the ERI. If the forecast reserve margin is 5 percentage points or more above the target reserve margin, the ERI is zero. If the forecast reserve margin is less than or equal to the target, the ERI is equal to one. For a forecast reserve margin within this range, the ERI declines linearly between 1 and 0. This method was used by both Edison and DRA for A.88-02-016, A.89-05-064, and the current A.90-06-001.

The approximation method is considered to closely approximate the Expected Unserved Energy (EUE) method, which the Commission found in D.86-05-024 should be the basis for calculating an ERI to reflect system capacity needs. The approximation method is, however, easier to implement than the EUE method, since the EUE method requires one extra model (a reliability model).

b. Position of Edison

Edison argues that GRA/IEP's recommendation of an ERI of 1.0 has flaws and is based on erroneous assumptions. Further, Edison believes that GRA/IEP's recommended 0.4 floor value is a new ERI methodology which is contrary to D.88-03-079.

Edison states that for the forecast period, its 1991 available firm generating capacity is projected to be 20,462 MW. However, GRA/IEP believes that this projection should be reduced by 1,122 MW because Edison's generating capacity resources should not include: (1) 200 MW for Castaic capacity; (2) 250 MW for additional spot capacity purchases associated with the Bonneville Power Administration (Bonneville)-Edison Sales and Exchange Contract because this purchase is discretionary; and (3) 672 MW for Palo Verde Unit 3 and Alamitos Unit 5 due to scheduled maintenance. Based on the removal of these three items, GRA/IEP recommends that Edison's generating capacity available for 1991 should be 19,340 MW. Edison contends that GRA/IEP's assumptions are incorrect.

According to Edison, it did not include any capacity in the resource plan for the Castaic pumped storage unit in the calculation of the ERI. Thus, removal of 200 MW of capacity from Edison's resource plan is improper. Also, according to Edison, removal of the 250 MW spot capacity purchase is inappropriate because the California Energy Commission (CEC) and this Commission have in their reports and decisions recognized that the Bonneville contract is an existing and approved contract which should be included in Edison's resource plan for calculating the ERI. Regarding Palo Verde Unit 3 and Alamitos Unit 5, Edison asserts that inclusion of these units in its generating capacity forecast of 20,462 MW is appropriate under the resource modeling assumptions used to calculate the ERI. Edison argues that removing these resources from the total capacity for maintenance outages is not appropriate. According to Edison, scheduled outages are recognized in the determination of the target reserve margin used in calculating the ERI. Therefore, Edison asserts that since maintenance outages are included in the determination of the required reserve margin, when the model determines the reserve margin, such resources cannot be removed again or this would be double-counting the outage.

Next, commenting on GRA/IEP's peak demand forecast, Edison argues that the GRA/IEP forecast of 18,299 MW is overstated by at least 2,034 MW for the following reasons: (1) the recorded 1990 peak demand of 17,647 MW which GRA/IEP used as the basis of its estimate, should be reduced by 1,094 MW for unused direct control load management; (2) the recorded 1990 peak demand of 17,647 MW should be reduced by 440 MW to adjust for higher than average temperature conditions; (3) GRA/IEP's projected 1991 forecast peak demand of 18,229 MW should be reduced by the escalation of the 300 MW Sacramento Municipal Utility District (SMUD) sale; and (4) GRA/IEP's 1991 forecast peak demand of 18,229 MW should be reduced by at least 200 MW for recently approved conservation programs.

According to Edison, by making the four adjustments described above, combined with using a 2% peak load growth escalation factor, rather than a 3.3% escalation factor, GRA/IEP's forecast peak demand would be reduced to about 16,200 MW. Edison believes that with these adjustments, GRA/IEP's forecast would then be consistent with Edison's forecast of 16,160 MW.

In response to GRA/IEP's argument on the appropriate peak load growth escalation factor, Edison contends that a 2% growth rate, rather than the CEC's 3.3% growth rate, recommended by GRA/IEP, should be used to calculate the 1991 forecast peak demand. Edison believes that the CEC's 3.3% growth rate is not applicable for several reasons. The CEC's 1987 peak forecast, shown in GRA/IEP's Exhibit 25, is not the actual recorded 1987 Edison peak (managed or unmanaged). The 1989-1993 peak forecasts are not officially adopted by the CEC as noted in the footnote on page 4 of Exhibit 25. Additionally, Edison argues that the years selected for determining the growth rate significantly impact the conclusions. Edison points out that if the 1990 to 1991 years are used, the CEC's growth rate is 2.6%. If the years 1988-95 are used, the CEC's growth rate is 2.4%. In summary, Edison's position is that the CEC data in GRA/IEP's Exhibit 25 is not a valid basis to establish the 1991 peak load growth escalation factor.

c. Position of DRA

DRA agrees with Edison that the Commission should adopt an ERI index of 0.0 for the forecast period. DRA disagrees with GRA/IEP's recommendation that ERI of 1.0 be adopted with a floor of 0.4.

DRA sees an inconsistency in GRA/IEP's position. DRA points out that in D.88-09-079 the Commission directed the parties to use "the load and resource assumptions developed during the ECAC proceeding" to derive the ERI. The Commission stated that this approach to ERI updating ensures consistency with the results of our ECAC proceedings without adding issues to the latter (D.88-09-079, p. 8, footnote 4). GRA/IEP did indicate in testimony that it agrees with DRA's policy that the same resource plan should be used for developing both the ERI and the IER as well as the revenue requirements of the utility. Although GRA/IEP offered testimony on the calculation of the ERI value, it did not offer any testimony on the use of the same resource plan for developing the IER. According to DRA, GRA/IEP relied on the load and resource assumptions that were used by Edison to determine the ERI, and made changes from there for purposes of its own ERI development. Therefore, DRA believes that the GRA/IEP analysis supporting its recommended IER of 1.0 has a fundamental flaw since it does not rely on the same resource plan for developing all components of this case.

Next, DRA argues that GRA/IEP's recommendation to modify the reserve margin approximation method to have a floor of 0.4 for the ERI should be rejected. DRA points out that the reserve margin method closely tracks the EUE method. If the same resource assumptions are used in each method, and the ERI is very close to zero under the approximation method, then, according to DRA, one would expect that it would be very close to zero under the EUE method as well.

Also, with regard to GRA/IEP's recommendation for a floor of 0.4 for the ERI, DRA points out that D.89-06-048, which GRA/IEP relies on, specifically addresses Pacific Gas and Electric Company (PG&E) which is highly dependent on hydro, and according to DRA, that decision is not applicable to Edison in the short term (D.89-06-048, p. 5, footnote 8).

DRA recommends that GRA/IEP pursue its recommendation to have an ERI floor of 0.4 in the Biennial Resource Planning Update proceeding, which is the appropriate forum to determine QF payment methodologies.

d. Position of GRA/IEP

GRA/IEP argues that the ERI proposed by Edison and DRA results from a methodological approach many times rejected by the Commission; that, contrary to assertions by Edison and DRA, the Commission has never approved that "1.0/0.0" ERI approach; and that in any event the use of correct load and resource data yields an ERI of 2.574, well in excess of 1.0, and not the ERI of zero proposed by Edison and DRA. Because of the fundamental disparity in position between the parties, GRA/IEP recommends, as an interim measure, that the Commission consider applying in this case the "1.0/0.4" ERI approach it adopted in D.89-06-048.

Also, GRA/IEP takes exception to Edison's and DRA's position on capacity valuation. According to GRA/IEP, Edison's proposed ERI of 0.6 is QF specific since in all other contexts Edison admits the value of additional capacity. GRA/IEP points out that in its direct testimony it has recited examples of instances where Edison has taken actions or made representations to this effect: (1) Edison's request for emergency capacity from QFs; (2) its support of the Bonneville capacity purchase contract, which the Commission approved, based on a 1990 ERI of 0.43 and a 1991 ERI of 0.56; and (3) its merger testimony that so-called surplus system capacity was worth no less than $60 per kW-year.

Accordingly, GRA/IEP urges the Commission to take note of the position taken by Edison and DRA in this matter and recognize that their ERI recommendation is belied by Edison's actions elsewhere. On the other hand, GRA/IEP believes that its recommendation is wholly in line and consistent with the capacity valuation reflected in these other contexts.

Regarding resource availability assumptions, GRA/IEP states that:

(1) Its revised ERI calculation of 2.574 reflects a correction for 200 MW of Castaic capacity;

(2) The exclusion of the purchase of the 250 MW spot capacity under the Bonneville contract is inconsistent with Edison's proposed ERI of zero but consistent with Edison's assumed ERI of 0.56 used to justify the contract's cost-effectiveness;

(3) GRA/IEP accepts Edison's position on the availability of Palo Verde Unit 3, but does not accept Edison's assertion that the deletion of Alamitos Unit 5 for a maintenance outage would result in a double-counting;

(4) Edison ignores the fact that it has never attempted to invoke all of the 1,094 MW for which it has load management in place, and does not plan its system based on the assumption that it will curtail service to these customers;

(5) Edison's reliance on average temperature conditions to establish "weather normalized" demand is inconsistent with its other weather-related conditions, such as hydro availability;

(6) GRA/IEP's revised ERI reflects a correction for escalating the 300 MW capacity sale to SMUD;

(7) It is incorrect for Edison to include conservation that is not currently in place because there is no assurance that the funding of these additional programs will yield the expected result; and

(8) The CEC's 3.3% demand growth rate should be favored over Edison's internal undocumented 2% proposed rate.

Lastly, GRA/IEP argues that neither Edison nor DRA cite any Commission determination or finding which can be construed as an adoption or endorsement of its 1.0/0.0 ERI approach. GRA/IEP believes that Edison's and DRA's reliance on last year's ECAC decision (D.90-01-048) is misplaced because the 1.0/0.0 ERI approach was not a subject of that proceeding. According to DRA/IEP, that decision represents the first time that Edison's ERI methodology yielded an ERI of zero, and there was no one in the case with an interest in seeing to the correct application of prior Commission determinations in that event.

e. <u>Discussion</u>

We will address GRA/IEP's argument that the use of correct load and resources data yields an ERI well in excess of 1.0 and not the ERI of zero proposed by Edison and DRA. The proposed GRA/IEP adjustments are addressed item by item.

(1) The 200 MW of Castaic capacity, apparently, is no longer in dispute since GRA/IEP's revised ERI calculation reflects this correction.

(2) Notwithstanding that purchase of the 250 MW of spot capacity under the Bonneville contract is discretionary, we conclude that this is firm capacity which is available to Edison. Since Edison may avail itself of this capacity when necessary, we find no merit to GRA/IEP's argument that it should not be included in Edison's resources for 1991. Therefore, GRA/IEP's adjustment is not adopted.

(3) Edison's argument is that Palo Verde Unit 3 and Alamitos Unit 5 are shown in the modeling of Edison's resources, and the availability or non-availability of these resources is properly accounted for in the modeling process. According to Edison, because all maintenance outages are reflected in the modeling, removal of these items would result in double-counting the outage. We believe that Edison's argument is valid. GRA/IEP failed to demonstrate that this is not so. Accordingly, the GRA/IEP adjustment is not adopted.

(4) The fact that Edison has never attempted to invoke all of the 1,094 M of load management that it has in place does not negate the fact that it is a resource that is available. Further, we should point out that the customers on load management schedules are served on a tariff which requires such customers to be curtailed when Edison has the need. Edison is obliged to serve these customers strictly in accordance with the tariff. Failure to

curtail such customers when necessary is discrimination against other customers who are in effect subsidizing the lower rates enjoyed by customers on load management rate schedules. Since Edison has the option to curtail all customers on these schedules when there is a need, we reject GRA/IEP's argument that load-management is not a viable resource.

(5) Edison's position is that the 17,647 MW recorded June 27, 1990 peak figure used by GRA/IEP is not representative because it includes 440 MW of load that would not have occurred under average conditions. Edison points out that its target reserve methodology accounts for extreme heat conditions on a probabilistic basis; therefore, average weather conditions should be assumed for the peak demand forecast. If GRA/IEP has reservations regarding this issue, it may raise its concerns in the next Biennial Resource Planning Update proceeding. For purposes of this proceeding, we conclude that it is reasonable to adopt Edison's position since Edison has allowed for extreme heat conditions in its target reserve methodology.

(6) The 300 MW capacity sale to SMUD, apparently, is no longer in dispute since GRA/IEP's revised ERI calculation reflects this calculation.

(7) Regarding conservation that is currently not in place, we believe that GRA/IEP may have a valid argument. Edison expects that the new programs will reduce 1991 peak load by 240 MW. However GRA/IEP's assumption is that none of this conservation will yield any result. We believe that GRA/IEP is overly pessimistic. For purposes of this discussion, we will assume 50% of the 240 MW does not become available.

(8) Lastly, we address GRA/IEP's argument that for 1991, the CEC's 3.3% growth rate should be used rather than Edison's figure of 2% that it uses for internal planning purposes.

We believe that GRA/IEP has a valid argument that Edison has not demonstrated why its 2% growth rate is appropriate for 1991. However, we believe that GRA/IEP's reliance on CEC's 3.3% factor is inappropriate too.

As Edison pointed out, the 3.3% CEC growth rate, which is for 1987-94, is overstated because it includes a 1987 recorded value unadjusted for weather. Further, the CEC specifically did not officially adopt this growth rate (Exhibit 25, footnote). And more importantly, this ECAC proceeding is concerned with 1991. We believe that a forecast for the 1987-94 period is not specific enough for our purpose.

Since GRA/IEP has relied on the CEC forecast, we will use the CEC data to derive a specific forecast for 1991. On this basis, the CEC 1990-91 forecast is calculated to be 2.7% (17399 MW ÷ 16943, Exhibit 25).

If the above 2.7% growth rate is used to evaluate GRA/IEP's argument, the ERI would still be zero:

	MW
1990 Recorded Peak used by GRA/IEP	17,647
Unused Load Management - Edison Position	(1,094)
Weather Normalization - Edison Position	(440)
50% Conservation Not Realized - GRA/IEP Position	120
	16,233
2.7% Growth	438
	16,671
1991 Capacity	20,493
Load with 2.7% Growth	16,671
Reserves %	22.9
Target Reserves %	16.0
Reserves Exceed Target %	7.8

As shown above, since the reserves are more than 5% above the target, the ERI is zero. (See ERI Background section B1.a).

In summary, we conclude that the Edison/DRA recommendation of an ERI of zero for the forecast period is reasonable. Accordingly, based on an ERI of zero, the resulting avoided cost payment to certain QF's during the forecast period is $0/kW.

Regarding GRA/IEP's request for a floor of 0.4 for the ERI, we believe DRA has a valid argument that simply because PG&E has a floor 0.4, that does not mean that the same should apply to Edison. PG&E is more hydro dependant that Edison. Therefore, we do not find GRA/IEP's recommendation based on PG&E D.89-06-048 persuasive.

2. Escalation of Marginal <u>Customer and Demand Costs</u>

a. <u>Background</u>

Following a motion by CLECA to update marginal unit customer and demand costs, on August 7, the ALJ ordered Edison to update its marginal unit customer and demand costs using the Data Resources, Inc. (DRI) forecast of the Gross National Product (GNP) Implicit Price Deflator. Edison provided the requested update. TURN filed a motion for reconsideration of the ALJ's ruling on August 10, 1990. TURN argued that the Commission has previously ruled that updates to such costs would not be considered in ECAC proceedings. Therefore, TURN believes that the ALJ's ruling was improper because it denied TURN proper notice and its right to be heard. TURN's motion for reconsideration was denied by the ALJ on September 6, 1990.

b. <u>Position of TURN</u>

TURN argues that the ALJ adopted a method for calculating marginal customer and demand costs without notice and an opportunity to be heard.

TURN notes that the August 7, 1990 ALJ ruling determines that "Edison shall update its marginal unit customer and demand costs using the DRI forecast of the GNP Implicit Price

Deflator, and provide new class marginal cost revenue responsibility percentages." According to TURN, this ruling violates both the laws and the Constitution of this state because it adopts a method for altering the previously adopted marginal customer and demand costs without providing notice and an opportunity to be heard.

Further, TURN points out that when it requested permission to offer evidence on marginal customer and demand costs which did not rely on a simple escalation methodology, the ALJ denied its request.

According to TURN, the sole basis for the ALJ's ruling is CLECA's claim that marginal customer and demand costs have increased by at least the rate of inflation. TURN asserts that CLECA did no analysis to support an increase in marginal customer and demand costs. Therefore, TURN contends that such an untested claim is not sufficient to support a change in the Commission's adopted methodology and the increase in residential rates that will result from this change.

Also, TURN notes that in Edison's general rate case decision (D.87-12-066), the Commission stated that marginal customer and demand costs would not be considered in ECAC proceedings. Therefore, TURN argues that D.87-12-066 may not be altered without a hearing. TURN cites Public Utilities (PU) Code § 1708 and the case of California Trucking Association v. PUC, (1977) 19 Cal. 3d 240, 245 in support of its position.

Also, TURN relies on PU Code §§ 454 and 728 which require that the Commission may not raise any rate except upon a showing before the Commission, and after a hearing. According to TURN, in this proceeding, in violation of the above-cited statutes, the Commission has not held a hearing or, indeed, developed any evidentiary basis for the adopted increase in marginal demand and customer costs and the corresponding increase in residential rates. TURN argues that, instead, the Commission has relied solely on the untested assertions of the industrial customers, the very parties who will stand to benefit if marginal costs are altered, to change the method of calculating marginal customer and demand costs in order to raise residential rates.

c. <u>Position of Edison</u>

Edison states that although marginal unit cost elements are not generally updated in ECAC proceedings, Edison did not oppose the updating of marginal unit demand and customer costs to reflect escalation in this ECAC because such updating was limited in scope and could be accommodated without delay. Due to a change in Edison's general rate case schedule, marginal unit demand and customer costs have not been updated since January 1, 1988. Edison believes that this has caused unanticipated effects on its customers. Therefore, Edison does not object to escalating these costs in this ECAC proceeding by applying DRI's forecast of the GNP Implicit Price Deflator.

Edison points out that the ALJ granted CLECA's motion requesting an update to reflect inflation, but permitted parties to present evidence that escalation should not occur and whether factors other than the DRI GNP Implicit Price Deflator should be used if escalation is ordered.

Edison argues that the ALJ's ruling permitted parties to present evidence of other escalation factors if they considered that the DRI factor was not appropriate. Edison asserts that TURN could have presented such evidence; however, it chose not to make any showing regarding the escalation of marginal customer and demand costs. Therefore, Edison submits that TURN did, in fact, have notice and an opportunity to be heard and its arguments to the contrary should be rejected by the Commission.

Regarding TURN's contention that there was no analysis to support the increase in marginal customer and demand costs, Edison believes that the DRI GNP Implicit Price Deflator is amply supported in the record and can lawfully be adopted by the Commission.

d. Position of CLECA

CLECA's witness, Barbara Barkovich, testified that use of the GNP Implicit Price Deflator is appropriate in this proceeding. She noted that the Commission has adopted the same mechanism for updating marginal generation demands costs for QF pricing purposes. She testified that she would expect marginal transmission and distribution demand costs as well as marginal customer costs to escalate at a rate similar to that of marginal generation demand costs. She testified that she was aware of no productivity gains which would cause these types of costs to change in a manner different that the GNP Implicit Price Deflator.

Regarding TURN's allegation that the ALJ's ruling violated its procedural due process rights, CLECA argues that there is no basis to TURN's allegation since TURN did not avail itself of the opportunity to present evidence. CLECA points out that while TURN presented an expert witness on other questions, it offered no evidence concerning the updating of the marginal unit customer and demand costs. TURN did not attack through expert testimony the ALJ's choice of the GNP Implicit Price Deflator as the mechanism for updating these costs. Nor did it present any evidence suggesting that the marginal customer and/or demand costs have remained stable or have declined in the three years since the issue of D.87-12-066.

e. Position of Industrial Users

Industrial Users argue that TURN continues to ignore the central issue addressed by the ALJ's ruling, i.e., the need to make some reasonable adjustment of the Commission's procedures for updating of marginal customer and demand changes, in light of the unanticipated deferral of Edison's test year 1991 general rate case.

According to Industrial Users, there is a compelling need for such an adjustment and it relates to two considerations. First, it makes no sense that the Commission should have to make its revenue allocation decisions in this proceeding on the basis of stale and outdated marginal cost data. Second, basic fairness and equity dictate that those customers whose revenue allocation would be severely skewed in the absence of updating receive the benefit of an adjustment to offset some of the undesirable consequences of the deferral of Edison's test year 1991 general rate case.

f. <u>Position of CMA</u>

CMA argues that the only asserted support for TURN's position is that the Commission decided in Edison's last general rate case that only marginal energy cost should be updated in ECAC proceedings. According to CMA, TURN ignores the fact that the Commission's decision was not a grant to TURN of the benefits of distorted cost allocation. CMA asserts that the Commission's decision was a compromise between accuracy and the need for speedy action on ECAC applications and that in making that compromise, the Commission expected it to apply only to two years of ECAC cases.

CMA points out that by the third year, which the current case represents, the Commission expected that fully updated marginal costs would be used for the ECAC, based on new general rate case data for all elements of cost. Thus, according to CMA, with the delay in Edison's general rate case, a major premise for the Commission's compromise of accuracy and expedited rate relief is no longer applicable.

Regarding TURN's contentions that it has been denied procedural due process, CMA contends that TURN makes a basic error in applying its cited statutory and court authorities for its position. CMA points out that TURN treats the ALJ's ruling allowing evidence to be submitted updating marginal costs as a decision of the Commission that the rates in this case will be based on the updated costs. And CMA believes that TURN fails to recognize that it had every reasonable opportunity during this proceeding to offer evidence and substantive argument to persuade the Commission that it should use old instead of new cost data.

In response to TURN's contention that the action of the ALJ was taken without adequate notice and evidentiary hearings, CMA submits that the authorities cited by TURN all pertain to the need for notice and hearing before the Commission acts, not before an ALJ makes a ruling on admission of evidence on which the Commission could rely, after full notice and hearing as TURN claims to be required. CMA believes that the principles of law requiring a hearing before action is taken by the Commission have been met.

g. <u>Discussion</u>

Although the Commission decided in Edison's last general rate case that only marginal energy cost should be updated in ECAC proceedings, the Commission expected that by the third year after that decision, there would be fully updated marginal costs available for this ECAC proceeding. But for the postponement of Edison's general rate case, this proceeding would have had the benefit of new general rate case data for all elements of cost. Therefore, the circumstances which the Commission had in mind when Edison's general rate case decision was issued, changed significantly.

When CLECA filed its motion in this proceeding arguing that, as a result of the postponement of Edison's general rate case, the situation created was a skewed and unfair picture of customer class marginal cost revenue responsibility, no party disputed that claim. Therefore, we believe that the ALJ correctly directed Edison to update its costs using an across-the-board escalation factor. The updating was a simple ministerial task and it was accomplished with minimum delay. More importantly, as a result, the Commission is now not in a situation where it has to base this decision on stale data.

TURN's reliance on PU Code §§ 454, 728, and 1708, and the California Trucking Association case reflects a basic misunderstanding of these authorities. The cited statutory and court authorities stand for the proposition that the Commission should provide parties with an opportunity to be heard before the Commission acts. In this case, TURN has been provided with notice and ample opportunity to be heard before the Commission acted. As pointed out by the intervenors, TURN chose not to introduce expert witness testimony to support its position that the Commission should use the old data.

Also, the ALJ correctly denied TURN's request to offer evidence on marginal customer and demand costs which did not rely on a simple across-the-board escalation methodology. TURN's request was, in effect, an attempt to relitigate the methodology for computing marginal costs and/or an attempt to selectively relitigate individual cost components. Just as TURN believes that there are certain individual items which should be addressed in the interests of their clients, the other parties no doubt have similar concerns regarding different items that would be advantageous to their clients. If TURN's request had been granted, other parties could have made similar requests. This proceeding could have then developed into a general ratecase proceeding. That is a result that negates the whole purpose of an ECAC proceeding.

Accordingly, we affirm the ALJ's rulings on updating marginal costs for revenue allocation purposes.

3. Gas Cost for Marginal <u>Energy and Demand Costs</u>

a. <u>Background</u>

Edison and DRA recommend that $3.25 per MMBtu average cost of gas which DRA used to prepare the revenue requirement in the joint recommendation (Exhibit 34) be used for the marginal energy cost calculation and revenue allocation purposes if the

Commission adopts the joint recommendation. TURN supports the DRA proposal.

However, Industrial Users, CMA, CSC, CLECA, and CCC disagree with Edison and DRA. They recommend a gas cost of $3.12 per MMBtu, based on the testimony of Industrial Users' witness Chalfant.

At the outset of this proceeding, the gas cost recommendations were:

DRA	$2.84 per MMBtu
Industrial Users	$3.12 per MMBtu
Edison	$3.40 per MMBtu

During the course of the proceeding, with the introduction of the joint recommendation which recommends a revenue requirement and IER, Edison, and DRA changed their recommendation to $3.25 per MMBtu.

b. <u>Position of Industrial Users</u>

Industrial Users argue that the proposal of Edison and DRA that the gas cost assumption purportedly underlying the joint recommendation be applied for revenue allocation purposes should be rejected in favor of permit' j a disposition of that issue on the merits.

Industrial Users contend that the joint recommendation, by its terms, disposes of only two issues in the case: revenue requirement and the appropriate level of the IERs to be employed in QF pricing calculations. However, two of the four proponents of the joint recommendation - Edison and DRA - contend that the joint recommendation assumes a specific gas cost and that that cost should be used in the calculation of the marginal energy costs factored into the allocation of the authorized Edison revenues. In contrast, another of the proponents of the joint recommendation - CSC - strenuously disclaims the incorporation of any specific gas cost into the joint recommendation and opposes the carryover application of the joint recommendation in the revenue allocation context.

Industrial Users submit that a figure agreed upon by only two of the parties to the proceeding should not be applied without further ado to control other issues in the case of direct and immediate concern to those parties not involved in the joint recommendation. Industrial Users assert that the Commission's proper course is to ignore the assumptions purportedly underlying the joint recommendation and to decide the issue of Edison's gas cost for purposes of the marginal energy cost and revenue allocation deliberations herein on the merits of that issue, i.e., on the basis of the record evidence presented on the issue.

Industrial Users' witness, Alan Chalfant, took issue with DRA's decision to resort to the SoCal ACAP proceeding for the joint recommendation gas cost input. According to Chalfant, if one's objective is to determine as accurately as possible Edison's gas costs for a revenue requirement and revenue allocation purpose in this proceeding, it makes no sense whatever to use SoCal's gas cost as the point of reference. Chalfant asserts that apart from the intrastate transportation component, Edison's gas costs are a function of its own gas procurement policies and bear no relationship to the average gas price paid by SoCal to procure supplies for its total system supply.

Industrial Users point out that their proffered gas cost of $3.12 is supported by substantial evidence. In summary, Industrial Users' witness, Chalfant, basically focused on the level of spot market gas costs at the California border, acknowledged by Edison as the most important factor affecting Edison's gas costs. That determination, in turn, required that Chalfant develop: (1) a figure reflecting the price of Permian Basin spot gas delivered to El Paso Natural Gas Company's (El Paso) main line, and (2) a figure for the interstate transportation of Edison's gas via the El Paso pipeline facilities. According to Chalfant, Edison's actual 1991 gas cost could be lower than his $3.12 figure because the El Paso transportation rate could be less. Industrial Users urge accordingly that Chalfant's recommended gas cost be adopted for purposes of the marginal cost and corresponding revenue allocation determinations.

c. <u>Position of CMA</u>

CMA also agrees with Industrial Users and the other intervenors that the $3.25 gas cost figure has no significance outside the context of the joint agreement.

Also, CMA agrees with Industrial Users that the marginal energy cost should be based on the best gas cost evidence in the record. CMA agrees with Industrial Users' witness Chalfant's testimony that the cost of firm gas supplies to SoCal in estimating Edison's cost of interruptible gas service is irrelevant.

d. <u>Position of CSC</u>

CSC submits that the $3.25 gas figure has no relevance even within the context of the Joint Recommendation. According to CSC, the Joint Recommendation, by its terms, does not represent any single set of underlying modeling assumptions or inputs. Further, CSC takes no position regarding the "correct" gas cost to be used in determining marginal energy cost.

e. <u>Position of CLECA</u>

CLECA agrees with Industrial Users and the other intervenors. CLECA is opposed, for purposes of determining the marginal energy cost, to the use of the gas cost figure "implicit" in the joint recommendation or to be adopted in the SoCal ACAP. CLECA supports the development of a cost of gas figure in this case based on record evidence.

CLECA points out that in their initial testimony, DRA and Edison presented very different natural gas cost estimates. DRA supported a $2.84 per MMBtu figure while Edison foresaw dramatic increases in gas costs and urged the adoption of a $3.40 per MMBtu figure. Industrial Users' witness, Chalfant, presented a case for a gas cost figure in between the DRA and Edison estimates at $3.12 per MMBtu. CLECA supported the lower DRA figure and utilized it in development of CLECA's proposed revenue allocation.

CLECA argues that in the joint recommendation, the DRA, Edison and the QF representatives reached an agreement on overall revenue requirement and on the IERs to be used for QF pricing purposes. These parties specifically did not agree on a single gas cost figure for any purpose. They did agree that, for QF pricing purposes, gas transportation costs should be determined using the gas volumes adopted in the most recent SoCal ACAP. Thus, CLECA contends that while the joint recommendation provided an overall revenue requirement proposal, it failed to provide any guidance on marginal energy costs because both DRA and Edison had backed away from their earlier gas cost proposals.

CLECA argues that the Commission should develop and implement a revenue allocation based on a marginal unit energy cost evidence in this proceeding. Also, if the intent of the parties to the joint recommendation is that this determination be based upon the results of the SoCal ACAP proceeding, CLECA vigorously protests. CLECA points out that it is not a party to that case and should not have to participate there to influence revenue allocation in this case. Further, CLECA contends that it has not been established why a SoCal weighted average cost of gas figure would be relevant to Edison's cost of gas. According to CLECA, Edison generally buys its gas on the open market, not from SoCal. And CLECA believes that under D.90-09-089 Edison will be prohibited from purchasing more than 65% of its gas from SoCal.

In summary, CLECA is troubled by the suggestion that revenue allocation should be based on a cost of gas figure which simply "falls out" of the joint recommendation. CLECA points out that there is no evidentiary support for this figure. No witness explained why it is a good estimate of Edison's gas costs for the next year. It is simply a number, chosen by DRA as a "middle ground" for purposes of facilitating agreement on the overall revenue requirement. CLECA submits that the Commission needs a firmer base for its adopted revenue allocation. According to CLECA, that sound foundation is provided by the testimony of Industrial Users' witness Chalfant.

f. Position of CCC

CCC agrees with Industrial Users and the other intervenors. CCC states that the $3.25 per MMBtu gas cost figure has no significance outside the context of the joint agreement. According to CCC, it is merely one price from a range of prices that, depending on other resource assumptions, could have emerged from the post-processing of DRA's cost simulation run. Viewing it as more than that would not only be contrary to the understanding set forth in the joint recommendation, but would attribute a significance to the number that it does not merit.

CCC argues that in D.87-12-066, Edison's general rate case decision, the Commission recognized that in some circumstances, the gas price used for purposes of cost allocation should not mirror the gas price used in determining the IER. CCC believes that this proceeding presents exactly such a case. Therefore, CCC urges the Commission to not use the gas price underlying the joint recommendation and create a false link between the gas price emerging from the DRA cost simulation computer run underlying the joint recommendation.

g. Position of Edison

Edison states that if the joint recommendation is not adopted, the Commission should use Edison's forecast average gas cost of $3.46 per MMBtu and the corresponding revenue increase of $494.5 million. Edison believes that its recommendation is consistent with the Commission's decision in Edison's last general rate case and ECAC proceedings. According to Edison, in those cases, the Commission calculated marginal energy costs and revenue allocation using a gas price consistent with the revenue requirement.

Edison argues that using an average gas price for revenue allocation that is consistent with the gas price underlying the revenue requirement helps maintain the rate relationships adopted in Edison's general rate case. Edison believes that such a procedure maintains a consistent Commission methodology for calculating revenue allocation and marginal energy costs.

According to Edison, the $3.12 per MMBtu proposed by Industrial Users should be rejected because it is an impermissible change of methodology in an ECAC proceeding. Edison contends that if Industrial Users' proposal is accepted, the gas price for revenue allocation will be different from the gas price used to develop the revenue requirement. Edison submits that if any consideration is to be given to Industrial Users' proposal, it should wait until Edison's next general rate case when the methodology for calculating marginal energy costs can be reevaluated.

h. Position of DRA

DRA agrees with Edison's position that the same gas price be used for developing the revenue requirement as is used for revenue allocation. DRA believes that the argument of Industrial Users should be rejected for several reasons.

DRA argues that the Industrial Users' recommendation is a change in methodology which should not properly occur in an ECAC proceeding. DRA notes that the Industrial Users' witness conceded that in past ECAC proceedings the Commission has used the same gas price for revenue requirement and revenue allocation calculations. Therefore, DRA believes that what Industrial Users is proposing is a new interpretation of "fuel price."

Further, DRA disagrees with Industrial Users' proposal to construe fuel price as the spot gas price that Edison can purchase gas at, instead of the price used to develop revenue requirement.

Also, DRA asserts that adoption of Industrial Users' proposal would skew the effect of rates on different customer classes. On the one hand, revenue requirement which has to be allocated among all customer groups would be based on one gas price, while at the same time, the actual allocation would be based upon marginal energy costs developed from a different gas price.

i. Discussion

We agree with Edison and DRA that we should continue to maintain a consistent methodology for calculating revenue allocation and marginal energy costs. However, we cannot adopt the Edison/DRA recommended gas cost of $3.25 per MMBtu simply because it underlies DRA's computer run that developed the IER of 9,531 Btu/kWh that is the subject of the joint stipulation. As testified by DRA witness Bill Lee, the $3.25 figure is nothing more than a compromise figure. And, as pointed out by the intervenors, prior to the joint recommendation, Edison and DRA were far apart on the appropriate gas cost.

On the other hand, Industrial Users' witness Chalfant has recommended a gas cost of $3.12 per MMBtu that is supported by substantial evidence.

As the intervenors point out, the parties to the joint agreement did not stipulate to any gas cost or resource assumptions. Moreover, the $3.12 figure may be used with other reasonable resource assumptions to develop the same IER of 9,531 Btu/kWh that the parties stipulated to in the joint agreement. The witnesses for Edison and DRA agreed that other reasonable resource assumptions would yield approximately the same IER using the DRA computer run. Therefore, we find that use of the $3.12 figure is not in conflict with the premise that there should be consistency between the methodology for calculating revenue allocation and marginal cost. Accordingly, we reject the Edison/DRA argument that the $3.12 figure should not be adopted because it represents a change in methodology.

In summary, we conclude that Industrial Users' recommended gas cost is amply supported by the evidence in this proceeding, and $3.12 per MMBtu should be used for purposes of developing revenue allocation.

4. Baseline/Nonbaseline Differential

a. Background

Pursuant to SB 987 and D.89-09-044, Edison recommends that the Commission reduce the nonbaseline to baseline rate ratio by increasing the baseline rate on January 1, 1991, 2.5% more than the average increase for the Domestic rate group. DRA proposes that the baseline rate be increased 5% more than the average increase for the Domestic group. TURN prefers Edison's proposal to that of DRA, but recommends a phase-in of the tier differential reduction with the beginning of the summer.

b. Position of Edison

Edison believes that the rationale for the DRA's proposal is based on a misconception about the nature of the deadline in SB 987. Edison contends that SB 987 imposes an entirely different deadline:

> "Baseline rates may not be increased so as to result in substantial elimination of any significant differential between baseline and nonbaseline residential rates in less than 30 months following the effective date of this section." (SB 987, p. 6.)

Edison argues that in carrying out the intent of the bill, the Commission desires to pursue the realignment vigorously but recognizes that it is "not to substantially eliminate any significant differential between baseline and nonbaseline rates for at least 30 months..." (D.88-10-062, pp. 2-3.) Edison contends that the Commission has established May 1991 as the deadline before which it may not make substantial reductions in the tier differential. (D.89-09-044, p. 7.) Therefore, Edison submits that its proposal makes steady, measured progress toward reducing the tier differential and is consistent with the Commission's decision in Edison's last ECAC proceeding. (D.90-01-048, p. 84.) And Edison's proposal takes into account the rate increases experienced by baseline customers in recent years.

Edison further argues that the seasonal phasing suggested by TURN is unwarranted. In PG&E's general rate case, the Commission reduced the differential between Tier 1 and Tier 2 rates, expressed in cents/kWh, by 25%. Based on Edison's original proposal (with a total revenue change of $686.8 million), there would only be a 2% reduction in the cents/kWh tier differential. In absolute terms, the maximum possible increase for baseline customers caused by Edison's proposal to decrease the tier differential is 60 cents per month. Edison believes that the impact on customers simply does not justify a phased implementation of Edison's proposed tier differential reduction.

c. Position of DRA

DRA believes that the additional 5% increase in the baseline increase over the Domestic average change is warranted in light of the intent of SB 987, as well as subsequent Commission decisions emphasizing the need to rapidly reduce tier differentials. DRA contends that the language of SB 987 clearly states that tier closure should be undertaken as expeditiously as possible.

> "In establishing residential rates, the commission shall reduce high nonbaseline residential rates as rapidly as possible. If the commission increases baseline rates pursuant to Section 739, revenues resulting from those increases shall be used exclusively to reduce nonbaseline residential rates." (Emphasis added. SB 987, Section 4.)

DRA asserts that it is cognizant of concerns about rate shock and the potential impact upon low income ratepayers of rapid tier closure. DRA believes that its tier closure proposal is reasonable, and is consistent with SB 987 and prior Commission decisions on this subject. DRA points out that the Edison's LIRA program exists to address the needs of those ratepayers for whom rate closure coincides with qualified financial need; and approximately 10% of Edison's Domestic customers receive LIRA.

d. Position of TURN

TURN believes that Edison's proposal is the maximum tier differential reduction that should be approved. In addition, because of the large overall increase, TURN supports delaying the implementation of the tier differential reduction until May, when the baseline quantities are adjusted.

TURN argues that Edison has already made substantial progress in reducing its tier differential. If Edison's tier closure proposal is adopted, its differential will be among the lowest of the major utilities. In light of this progress, TURN sees no reason to adopt DRA's proposal.

TURN points out that DRA's tier closure proposal will cause rate increases of more than 15% for customers who use at or below their baseline allowance. TURN considers this increase excessive, especially in light of the increase that residential customers have experienced over the last few years.

TURN submits that SB 987 directed the Commission to reduce the tier differential in order to avoid high winter gas bills. SB 987 also directed the Commission to avoid excessive rate increases and not to substantially eliminate any significant differential between the two tiers. According to TURN, DRA's proposal simply ignores these legislative directives.

e. Discussion

We believe that DRA's proposal is unnecessarily harsh on customers with usage at or below baseline quantities. Approximately 33% of Edison's domestic customer bills fall into this category. Even with the revised lower revenue requirement adopted by the Commission in this decision, if DRA's proposal is adopted, the increase to these customers would be close to 15%. Since the system average increase is 6.8%, and the increase to the residential class as a whole is 9.3%, DRA's proposed increase to customers at baseline usage is excessive.

DRA's argument that 10% of Edison's customers receive assistance under LIRA is not persuasive. A majority of customers with usage at or below baseline quantities are not on LIRA.

On balance, we agree with TURN that Edison's 2.5% Baseline/Nonbaseline differential proposal is a more acceptable alternative, and it is a measured response to SB 987. We adopted a 2.5% Baseline/Nonbaseline differential in Edison's last ECAC rate change (D.90-01-048, p. 34) on the recommendation of Edison and DRA. We see no reason to change this rate of closure. Accordingly, we will adopt Edison's recommendation. On this basis, the increase to customers at or below baseline quantities will be approximately 11.8%.

However, we are not persuaded by TURN's argument that implementation of the tier differential reduction should be delayed until May. We believe that the impact caused by Edison's tier closure proposal does not justify a phased implementation. It should be implemented on January 1, 1991 along with all other rate changes.

5. <u>Revenue Allocation</u>

Edison, DRA, and intervenors representing CLECA, Industrial Users, and CMA recommend that the Commission allocate the total combined revenue requirement at 100% of Equal Percent of Marginal Cost (EPMC). TURN recommends a 2% cap above system average percentage change as a limit to the full EPMC revenue allocation.

Edison, DRA, and the intervenors argue that even on the basis of the residential increases over system average percentage change identified by TURN, the burden on Edison's residential customers appears to fall well within the range of tolerable limits established in earlier Commission decisions. The intervenors urge accordingly, that TURN's proposed cap be rejected and that the Commission's long-standing goal of full EPMC on the Edison system by 1990 be effectuated on January 1, 1991.

TURN argues that Edison and the others overlook the fact that the Commission in Edison's last general rate case decision stated that:

> "The consideration of revenue allocation issues in ECAC, however, does not and should not include relitigation of the marginal cost structure and levels adopted in this proceeding." (D.87-12-066, p. 264.)

According to TURN, the Commission has linked the achievement of a full EPMC revenue allocation and the use of "stable marginal costs".

As we stated previously, Edison's test year 1987 general rate case D.87-12-066 was based on the Commission's expectation that Edison's next general rate case rate design decision would be issued in three years. However, Edison's general rate case rate design decision was postponed by an additional eighteen months (D.89-08-036). Therefore, TURN's reliance on D.87-12-066 is no longer appropriate. These changed circumstances now make it necessary for the Commission to modify that decision. Accordingly, TURN's argument is not adopted.

As set forth in the table above (in the Summary of Decision section of this decision), based on updated marginal unit customer and demand costs, Industrial Users' gas cost of $3.12 per MMBtu, and a full EPMC revenue allocation, the increase to the residential class is 10.1%. The system average increase is 7.6%. Therefore, the increase above system average percentage change to the residential class is 2.5%.

Typically, when the proposed system average percentage change is 5% over system average, we have employed a 5% cap to limit the amount of increase to the residential class. However, we are not persuaded that the 2.5% increase above system average in this case is disproportionately burdensome to the residential class. Accordingly, TURN's request for a 2% cap over system average is denied.

As stated previously, the Commission is considering revenue changes associated with other applications. The proposed revenue increase, for all Edison's proceedings currently before us, will be allocated to achieve full EPMC based rates for all classes effective on January 1, 1991. Such a revenue allocation of the total January 1, 1991 combined revenue requirement at 100% of EPMC continues the Commission's policy of achieving full EPMC (D.87-12-066, Conclusion of Law 130).

Details of the adopted revenue allocation are set forth in the tables contained in Appendix C.

6. <u>Miscellaneous Items</u>

a. <u>Request for Finding of Eligibility</u>

On October 19, 1990, pursuant to Rule 76.54 of this Commission's Rules of Practice and Procedure, TURN filed a request for a finding of eligibility for compensation in this proceeding. Under the terms of the Rule, such a request must be filed within 30 days of the first prehearing conference <u>or</u> within 45 days after the close of the evidentiary record. TURN's request complies with the second option.

Rule 76.54(a) (as revised in D.85-06-126) sets forth four requirements that should be addressed in an eligibility filing. Each of these elements will be discussed below.

> (1) A showing by the customer that participation in the hearing or proceeding would pose a significant financial hardship. A summary of the finances of the customer shall distinguish between grant funds committed to specific projects and discretionary funds. If the customer has met its burden of showing financial hardship in the same calendar year, as determined by the Commission under Rule 76.05, 76.25, or 76.55, the customer shall make

reference to that decision by number to satisfy this requirement.

TURN has previously been found to have met its burden of showing financial hardship for calendar year 1990 in D.90-09-024, dated September 12, 1990. Therefore the requirement of Rule 76.54(a)(1) has been satisfied.

(2) A statement of issues that the customer intends to raise in the hearing or proceeding.

Since TURN had already completed its expected participation at the time it filed its request, the issues raised by TURN are already matters of record, particularly as set forth in the prepared testimony of TURN's witness and in TURN's cross-examination and briefs. TURN participated on the issues of marginal cost, revenue allocation and the residential tier differential.

(3) An Estimate of the compensation that will be sought.

Depending upon the Commission's decision, TURN states that it may request approximately $30,000 for its work in this case. This estimate of potential compensation is based on an assumed 150 hours of attorney time at an hourly rate of $150, expert witness expenses of $5,000 and $2,500 for "other reasonable costs," primarily postage, telecommunications, and copying expenses. The precise amount of compensation and the reasonableness of the compensation sought will be addressed in TURN's request for compensation filing after the Commission has decided this matter.

(4) A budget for the customer's presentation.

TURN's budget for this case is $30,000, as discussed above in connection with the estimate of compensation.

We conolude that TURN has met all of the requirements of Rule 76.54(a) and therefore should be found eligible for compensation in this proceeding.

b. <u>Fuel Inventory Levels and Carrying Costs</u>

DRA contends in its opening brief that specific forecasts of fuel carrying costs and the Chevron option payments should be adopted regardless of whether the Commission adopts the joint recommendation. Edison disagrees. Edison argues that these expenses are no different from any other expenses that underlie the joint recommendation, such as coal, hydro, or nuclear generation, and there is no reason for the Commission to decide such issues if the joint recommendation is adopted. Edison points not that forecasts of these expenses were included in the recommended revenue requirement in the joint recommendation and specific values are not necessary to implement the joint recommendation.

We agree with Edison that specific forecast inventory levels and carrying costs should not be adopted as this would involve some of the resource assumptions not accepted by the parties to the joint recommendation. Accordingly, DRA's request is denied.

c. <u>AER</u>

The Commission by I.90-08-006 suspended the AER for all jurisdictional utilities on August 8, 1990. In the joint recommendation the parties recommend that if the Commission reinstates the AER or adopts a successor procedure, 100% of the expenses and revenues subject to the AER or successor procedure should be recorded in the Energy Cost Adjustment Account until ECAC rates reflecting a new forecast of fuel and purchased power expense have been made effective by the Commission in a subsequent annual ECAC filing.

TURN takes no position on the revenue requirement increase and IER contained in the joint recommendation. TURN strongly objects, however, to paragraph 3 of the exhibit entitled

"Ratemaking Treatment of ECAC Expenses." According to TURN, this paragraph attempts to prejudge the outcome of OII 90-08-006 and any successor proceeding by recommending that Edison be exempt from any AER or similar mechanism the Commission may adopt. TURN recommends that paragraph 3 of the joint recommendation be specifically rejected.

Paragraph 3 of the joint recommendation states:

> "3. Ratemaking Treatment of ECAC Expenses
> The parties recommend that if the Commission, in OII 90-08-006, reinstates the Annual Energy Rate ("AER") or adopts a successor procedure, 100% of the expenses and revenues subject to the AER or successor procedure shall be recorded in the Energy Cost Adjustment Account until ECAC rates reflecting a new forecast of fuel and purchased power expense has been made effective by the Commission in a subsequent annual ECAC filing." (Emphasis added, Exhibit 34, p. 2.)

Edison argues that it would be unfair to apply an incentive mechanism such as the AER to a forecast of ECAC-includable costs after such costs were developed in anticipation of the continued suspension of the AER. And, according to Edison, it would also be unfair to apply the AER or any other incentive procedure to only part of the forecast period.

Edison points out that if an AER (based on twelve months of forecasted data) is placed into effect part way through the forecast period, the Company will not have a reasonable opportunity to recover its fuel and purchased power costs nor will the ratepayer pay rates which represent a reasonable forecast of fuel and purchased power costs expected to be incurred during the period which the AER is in effect.

We agree that reinstatement of the AER or a successor mechanism could result in time-related imbalances of expenses and revenues if the reinstatement were made part way through a forecast period. However, any transition procedures to alleviate those imbalances properly belongs in I.90-08-006, not this proceeding. In order to reserve the issue for I.90-08-006, we will adopt TURN's recommendation to reject the terms of paragraph 3 of the joint recommendation.

TURN raises a valid point regarding possible future petitions for modification of this decision based on claimed changes in underlying assumptions to the joint agreement. We specifically decline to accept the methodology or assumptions underlying the parties' estimates of Edison's revenue requirement or the IER. Therefore, we will not entertain any petitions for modification of gas cost or any item underlying the joint recommendation adopted in this proceeding.

d. Street Lighting

CAL/SLA supports a revenue allocation based on full EPMC. Since revenue allocation in this decision is based on full EPMC, the street light customer group receives a 3.6% reduction in revenues as compared to a system increase of 7.6%. This means that the street light group would receive an 11.2% reduction relative to the system increase. In past proceedings the Commission has at times placed floors on the reduction to any customer group in revenue allocation. Given the size of the reduction to street lighting customers if full EPMC is adopted here, a floor should be considered. However, the street lighting group is only about 1% of Edison's revenue requirement. Thus, placing a floor on the street light group would provide little added revenue reductions to other groups. This, coupled with the Commission's desire to move to a full EPMC allocation makes the adoption of a floor on the revenue allocation for street light customers unnecessary here.

CAL/SLA also recommends that an "unbundled approach to rate design should be employed in order to inform street light customers of the separate charges for energy, customer access, facilities maintenance, and rental" and that "energy, demand, and customer charges should be based on marginal costs and the EPMO revenue allocation." This recommendation will not be considered here since it clearly involves the litigation of rate design issues which is inappropriate for this ECAC proceeding and is more appropriately considered in a general rate case.

__Comments on Proposed Decision__

Pursuant to PU Code § 311 and the Commission's Rules of Practice and Procedure, the Proposed Decision was published on November 16, 1990. Comments were timely filed by CSC, DRA, Industrial Users, and TURN. Reply comments were timely filed by CLECA, CSC, and Edison.

After considering the comments, we affirm the Proposed Decision. Nonsubstantive corrections were made and clarification provided where necessary.

__Findings of Fact__

1. On June 1, 1990, Edison filed this application in which it requested a revenue increase of $479 million on an annual basis for service rendered on and after January 1, 1991.

2. While hearings were in progress and based on a perceived interest among certain parties in reaching a compromise regarding the revenue increase and an appropriate IER, DRA made a compromise proposal, which resulted in a joint recommendation which was executed on September 18, 1990.

3. The "Joint Recommendation of Southern California Edison Company, Division of Ratepayer Advocates, California Cogeneration Council, and Cogenerators of Southern California", recommend an ECAC (Energy Cost Adjustment Billing Factor (ECABF)) revenue increase of $287.5 million.

4. The testimony of the parties supports a range of forecast revenue requirements and IERs.

5. The jointly recommended IER of 9,531 Btu/kWh also falls within the range of positions advocated in this proceeding.

6. The parties' support of the joint recommendation is based upon the Commission's adoption of its terms and conditions.

7. The requested revenue increase is based upon the joint recommendation and reflects changes to the ECABF, ERABF, and MAABF, and LIS which are not disputed by the parties to the joint recommendation.

8. In addition to the revenue increase requested in this ECAC application, the combined January 1, 1991 revenue changes associated with other pending applications need to be considered in this proceeding for revenue allocation and rate design purposes.

9. The Commission suspended the AER for all jurisdictional utilities on August 8, 1990.

10. The parties recommend that if the Commission, in OII 90-08-006, reinstates the AER or adopts a successor procedure, 100% of the expenses and revenues subject to the AER or successor procedure should be recorded in the Energy Cost Adjustment Account until ECAC rates reflecting a new forecast of fuel and purchased power expense have been made effective by the Commission in a subsequent annual ECAC filing.

11. The rate design adopted in this decision, including design of the customer, demand, and energy charges, should be in accordance with the CEPC rate design methodology adopted in Edison's last general rate case for ECAC proceedings.

12. Edison proposes to begin to phase out rate limiters by increasing the average and on-peak rate limiters effective January 1, 1991.

13. DRA concurs with Edison's methodology for increasing the rate limiters.

14. DRA proposed a minimum bill charge of 8.5 cents per day for the Low-Income Domestic rate.

15. Edison does not oppose DRA's proposal that the minimum bill charge on Rate Schedule No. D-LI (Domestic Low Income) be reduced from 10 cents to 8.5 cents per day.

16. To implement DRA's proposal, Edison requests that the Commission include an ordering paragraph in this decision with the following language to be substituted where appropriate in the tariff:

Minimum Charge:

"The Base Rate Energy Charge shall be subject to a daily Minimum Charge of $0.085 per single-family accommodation. In determining when the Base Rate Minimum Charge is applicable, the number of kilowatthours used is multiplied by 85 percent of an Annualized Base Rate of...."

17. To establish the total energy rates by time-of-use period and season, in accordance with the CEPC procedure adopted for Edison, Edison proposes to set the off-peak energy charges and second-block energy charges at 5 cents per kilowatthour (excluding the Low Income Rate Assistance Surcharge and the Public Utilities Commission Reimbursement Fee) with the on- and mid-peak energy rates set to collect the remaining revenue requirement (after the customer and demand charges have been set) and to reflect the marginal energy cost ratios adopted in this proceeding.

18. This proposal is unopposed and consistent with Edison's last general rate case and last two annual ECAC proceedings.

19. Edison, DRA, CSC, and CCC agreed in the joint recommendation (Exhibit 34) that for the determination of QF payments, particularly through avoided cost postings, Edison shall determine gas transportation costs using the gas volume adopted by the Commission in the most recent SoCal Annual Cost Allocation Proceeding (ACAP) beginning with A.90-03-018.

20. The parties to Exhibit 34 recommend that the Commission adopt the principle that Edison's QF payments be determined using the gas transportation costs based on the gas volumes adopted by the Commission in the SoCal ACAP decision in effect on the first day of each QF payment period.

21. The joint recommendation (Exhibit 34) sets forth the annual average avoided cost IER of 9,531 Btu/kWh and the time-differentiated avoided cost IERs as follows:

	Peak	Mid	Off	Super Off-Peak
Summer	13,574	8,402	8,620	N/A
Winter	N/A	10,586	9,562	8,128

22. No party, other than the parties to the joint recommendation, proposed an IER and no party objected to this recommendation.

23. Both Edison and DRA recommended that the Commission adopt an ERI of 0.0 for the Forecast Period.

24. GRA/IEP recommended that the Commission adopt an ERI of 1.0 and that a floor value of 0.4 be established.

25. Based on the resource assumptions adopted in this decision, Edison's reserves are more than 5% above target. Therefore, an ERI of zero is reasonable.

26. Since PG&E is more hydro sensitive than Edison, GRA/IEP's recommendation of an ERI floor value of 0.4 based on PG&E decision D.89-06-048 is not persuasive.

27. Upon the motion by CLECA to update marginal unit customer and demand costs, the ALJ, on August 7, 1990, ordered Edison to update its marginal unit customer and demand costs using the DRI forecast of the GNP Implicit Price Deflator.

28. TURN filed a motion for reconsideration of the ALJ's ruling on August 10, 1990.

29. TURN's motion for reconsideration was denied on September 6, 1990.

30. TURN argues that it was denied procedural due process to the extent that it was deprived of notice and the opportunity to present testimony.

31. The record in this proceeding shows that TURN was provided ample notice and the opportunity to present expert witness testimony that there was no need for customer marginal demand costs to be updated to compensate for inflation. TURN chose not to avail itself of the opportunity.

32. There is ample expert witness testimony in this proceeding to support the need for updating 1988 marginal costs to offset the effects of inflation.

33. Edison and DRA recommend that the Commission adopt an average gas price of $3.25/MMBtu for the purpose of determining the marginal energy costs and revenue allocation.

34. Industrial Users, CMA, CCC, CLECA, and CSC contend that the average gas cost for purposes of revenue allocation should be $3.12/MMBtu.

35. Industrial Users' gas price of $3.12 MMBtu is supported by the testimony in the record and should be used for purposes of the marginal energy cost calculation and revenue allocation in this proceeding.

36. Use of a gas cost figure of $3.12/MMBtu for purposes of the marginal energy cost calculation and revenue allocation in this proceeding does not conflict with the premise that there should be consistency between the methodology for calculating revenue requirement and marginal cost for revenue allocation.

37. Pursuant to Senate Bill 987 and D.89-09-044, Edison recommends that the Commission reduce the nonbaseline to baseline rate ratio by increasing the baseline rate on January 1, 1991, 2.5% more than the average increase for the Domestic rate group.

38. DRA proposes that the baseline rate be increased 5% more than the average increase for the Domestic group.

39. TURN prefers Edison's proposal to that of DRA, but recommends a phase-in of the tier differential reduction with the beginning of the summer.

40. Edison's tier closure recommendation continues use of the 2.5% rate over system average increase adopted in Edison's last ECAC proceeding, and it is a measured response to SB 987. Continuation of this closure rate is a more acceptable alternative to DRA's 5% recommendation.

41. With Edison's 2.5% closure recommendation, the resulting increase to customers using baseline quantities is not sufficient to delay implementation of the recommendation to May 1991.

42. Edison, DRA, and intervenors representing CLECA and Industrial Users recommended that the Commission allocate the total combined revenue requirement at 100% of EPMC.

43. TURN recommends a 2% cap above system average percentage change as a limit to the full EPMC revenue allocation.

44. With a full EPMC revenue allocation, the proposed increase to the residential class is not sufficient to justify implementation of a 2% above system average percentage cap.

45. For the Forecast Period, Edison projects its 1991 available firm generating capacity to be 20,462 MW.

46. GRA/IEP recommends that Edison's generating capacity available for 1991 should be 19,340 MW.

47. Because GRA/IEP believes that the Castaic capacity is not a firm resource available to Edison during the summer period, GRA/IEP believes that Edison's 1991 forecast of generating capacity of 20,462 MW should be reduced by 200 MW.

48. On October 18, 1988, the Bonneville Power Administration and Edison executed a 20 year Sales and Exchange Contract ("Contract").

49. Starting from July 1, 1989, the Contract authorizes Edison to purchase 250 MW of capacity and about 1.2 billion kilowatt-hours of energy annually. Edison may also purchase 250 MW of spot capacity.

50. GRA/IEP believes that since the purchase of this capacity is discretionary, the 1991 forecast of generating capacity of 20,462 MW should be reduced by 250 MW.

51. GRA/IEP recommends that Edison's 1991 available firm generating capacity of 20,462 MW be reduced by 672 MW for Palo Verde Unit 3 and Alamitos 5 scheduled maintenance.

52. DRA revised its forecast start date of the scheduled outage for Palo Verde Unit 3 from August 24, 1991 to March 16, 1991.

53. Edison forecasts that its 1991 expected managed and peak demand load will be 16,160 MW.

54. GRA/IEP forecasts Edison's peak demand to be 18,229 MW.

55. In forecasting its 1991 peak demand of 18,229 MW, GRA/IEP escalated the June 27, 1990 recorded peak demand of 17,647 by 3.3% based on the peak demand growth estimated by the CEC for the period 1987-1984. This estimate was not adopted by the CEC, it is based on data that is not temperature adjusted, and it is not specific to the 1991 forecast period.

56. Edison believes that a 2% rather than a 3.3% growth rate should be used to calculate the 1991 forecast peak demand. However, Edison did not provide support for its estimate.

57. Based on the CEC forecast Exhibit 25, for purposes of calculating the ERI, a peak demand growth rate of 2.7% is more appropriate for the 1991 forecast period.

58. For purposes of calculating the ERI, it is reasonable to assume that 50% of Edison's new conservation programs may not yield results during the 1991 forecast period.

59. Even with the use of a 2.7% peak demand growth rate and a 50% reduction in Edison's estimate of new conservation program results, Edison's estimated ERI of zero for the 1991 forecast period is reasonable.

<u>Conclusions of Law</u>

1. The joint recommendation of Edison, DRA, CSC, and CCC is reasonable and should be adopted, except for paragraph 3 which is rejected.

2. The adoption of the joint recommendation is not an adoption of the underlying assumptions that were included in DRA's computer run that developed the revenue requirement and the IER agreed to by the parties to the joint recommendation.

3. Paragraph 3 of the joint recommendation should not be adopted by the Commission because transition procedures to

alleviate time-related imbalances of expenses and revenues, if any, should be addressed in I.90-08-006.

4. Since TURN has had the opportunity to be heard before the Commission acted in this proceeding, there is no merit to TURN's argument that it was denied procedural due process. Accordingly, the ALJ's rulings on the updating of marginal costs should be affirmed.

5. The jointly recommended IER of 9,531 Btu/kWh is reasonable and should be adopted.

6. The revenue changes authorized in this proceeding, as set forth below, are reasonable and should be adopted.

	Millions of Dollars
Energy Cost Adjustment Billing Factor (ECABF)	$288.8
Electric Revenue Adjustment Billing Factor (ERABF)	182.0
Palo Verde 2	(2.5)
Major Additions Adjustment Billing Factor (MAABF)	(15.1)
Low Income Surcharge (LIS)	6.2
Total	459.4

7. The total January 1, 1991 combined revenue change should be based on the Commission's decision in this proceeding and the decision in other proceedings which authorize such revenue requirement changes.

8. The rate design procedures followed by Edison in this proceeding are in accordance with CEPC previously adopted for Edison by the Commission and should be adopted.

9. Edison's proposal to begin to phase-out rate limiters by increasing the average and on-peak rate limiters above what they

otherwise would have been is consistent with prior Commission decisions and should be adopted.

10. A minimum bill charge of 8.5 cents per day for the Low Income Domestic rate which gives such customers a 15% discount compared to what these customers would otherwise pay under the domestic rate, is reasonable and should be adopted.

11. To implement the minimum bill charge of 8.5 cents per day for the Low Income Domestio rate, Edison's tariff schedule D-LI should be revised to include the following language where appropriate in the tariff:

> "The Base Rate Energy Charge shall be subject to a daily Minimum Charge of $0.085 per single-family accommodation. In determining when the Base Rate Minimum Charge is applicable, the number of Kilowatthours used is multiplied by 85% of an Annualized Base Rate of...."

12. Edison's proposed off-peak energy charge of 5 cents per kilowatthour (excluding the Low Income Rate Assistance Surcharge and the Public Utilities Commission Reimbursement Fee) with the on- and mid-peak energy rates set to collect the remaining revenue requirement and reflect marginal energy cost ratios is reasonable and should be adopted.

13. The methodology jointly recommended by Edison, DRA, CCC, and CSC for determining QF payments, particularly through avoided cost postings, by using the gas volume adopted by the Commission in the most recent SoCal ACAP beginning with A.90-03-018 is reasonable and should be adopted.

14. The principle that Edison's QF payments be determined using gas transportation costs based on the gas volumes adopted by the Commission in the SoCal ACAP decision in effect on the first day of each QF payment period is adopted.

15. The jointly recommended time-differentiated IERs as set forth below are reasonable and should be adopted.

	Peak	Mid	Off	Super Off-Peak
Summer	13,574	8,402	8,620	N/A
Winter	N/A	10,586	9,562	8,128

16. Edison's and DRA's recommended ERI of 0.0 for the Forecast Period is reasonable and should be adopted.

17. An average gas price of $3.12/MMBtu for the purpose of determining marginal energy costs and revenue allocation is reasonable and should be adopted.

18. Edison's proposed reduction of the nonbaseline to baseline rate ratio by increasing the baseline rate on January 1, 1991, 2.5% more than the average increase for the Domestic rate group is reasonable and should be adopted.

19. The recommended revenue allocation of the total January 1, 1991, combined revenue requirement at 100% of EPMC continues the Commission's policy of achieving full EPMC and should be adopted.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission, on or after the effective date of this order, and at least 3 days prior to their effective date, revised tariff schedules for electric rates based on the adopted revenue requirement reflected in Appendix C to this decision. Such rate schedules shall reflect any changes made by the Commission in the revenue requirement adopted in the other proceedings that are considered herein for revenue allocation and rate design purposes.

2. The revised tariff schedules shall become effective on or after January 1, 1991, and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. Given the postponement of Edison's test year 1991 general rate case, the update of Edison's marginal unit customer and demand costs using the Data Resources, Inc. forecast of the Gross National Product Implicit Price Deflator shall be adopted. Decision 87-12-066 shall be modified accordingly.

4. An Energy Reliability Index value of 0.0, an annual Incremental Energy Rate (IER) of 9,531 Btu/kWh, and time-differentiated IER's as set forth in the joint recommendation attached to this decision as Appendix B shall be adopted.

5. A gas cost of $3.12 per MMBtu as recommended by Industrial Users for purposes of calculating marginal energy and demand costs in preparation of the revenue allocation estimate in this proceeding shall be adopted.

6. A revenue allocation procedure based on 100% of Equal Percent of Marginal Cost (EPMC) without any caps shall be adopted.

7. The adopted revenue increase in this proceeding and the adopted revenue increases for all Edison's proceedings currently before us, shall be allocated to achieve full EPMC based revenue allocation for all classes effective on January [illegible] 1991.

8. The Class Equal Percent Change methodology previously adopted for Edison by the Commission shall be continued in the design of customer, demand, and energy charges.

9. The rate imiter phase-out procedure proposed by Edison shall be adopted.

10. The Low Income Domestic Rate Adjustment minimum bill charge of 8.5 cents per day proposed by Division of Ratepayer Advocates shall be adopted.

11. The Time-of-Use rate schedule changes proposed by Edison whereby off-peak energy charges and second-block energy charges are set at 5 cents per kWh shall be adopted.

12. The temporary suspension of Edison's Annual Energy Rate shall be continued until the end of the Forecast Period, unless the Commission modifies the term of the suspension in a subsequent order.

13. Since the rates authorized by this decision shall become effective on January 1, 1991, this decision shall be made effective on the date of signature.

14. This proceeding shall remain open to address reasonableness issues now pending before the Commission.

This order is effective today.

Dated December 19, 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

[illegible]

[illegible] Executive Director

APPENDIX A
Page 1

List of Appearances

Applicant: Richard K. Durant, Frank J. Cooley, Bruce A. Reed, Michael D. Mackness, and Carol B. Henningson, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Mark P. Trinchero, Attorney at Law, and Messrs. Lindsay, Hart, Neil & Weigler, by Michael P. Alcantar, Attorney at Law, for Cogenerators of Southern California; Barkovich & Yap, by Barbara Barkovich, for Barkovich & Yap; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth, Joseph S. Faber, and Evelyn K. Elsesser, for California Large Energy Consumers Association; Messrs. Morrison & Foerster, by Jerry R. Bloom and Lynn Haug, Attorneys at Law, for California Cogeneration Council; Messrs. McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for Cities of Oxnard and Irvine; David R. Clark, Attorney at Law, for San Diego Gas & Electric Company; Thomas P. Corr, Attorney at Law, for Independent Power Corporation; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Philip DiVirgilio, for Destec Energy; Karen Edson, for KKE & Associates; Norman J. Furuta, Attorney at Law, for Department of the Navy; Grueneich & Ellison, by Dian M. Grueneich and Matthew Brady, Attorneys at Law, for California Department of General Services; Messrs. Lindsay, Hart, Neil & Weigler, by Paul Kaufman, Attorney at Law, for Kern River Cogeneration Company; Karen N. Mills, Attorney at Law, for California Farm Bureau Federation; Jeff Nahigian, for JBS Energy, Inc.; John B. Quinley, for Cogeneration Service Bureau; Donald G. Salow, for Henwood Energy Services, Inc.; Bartle Wells Associates, by Reed V. Schmidt, for California City-County Street Light Association; Donald W. Schoenbeck, for Regulatory & Cogeneration Services, Inc.; Joel R. Singer and Michel P. Florio, Attorneys at Law, for Toward Utility Rate Normalization; Messrs. Roberts & Kerner, by Douglas K. Kerner, Attorney at Law, for Geothermal Resources Association and Independent Energy Producers Association; Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers; Messrs. Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Ronald Liebert, Attorneys at Law, for Industrial Users; Nancy Thompson, for Barakat & Chamberlin; Kathleen Treleven, for Morse, Richard, Weisenmiller & Associates; Randolph L. Wu, Richard Baish, and Michael Ferguson, for El Paso Natural Gas Comoany; Thomas A. Tribble, for Regents-University of California; Patrick J. Bittner, Attorney at Law, for California Energy Commission, and Janet Rinaldi, for self.

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List of Appearances

Division of Ratepayer Advocates: Ira Kalensky and Kathleen Mahoney, Attorneys at Law, and Bill Yi Lee.

Commission Advisory and Compliance Division: Ali Miremadi.

(END OF APPENDIX A)

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A. 90-06-001
Exhibit No. 34
Date ______

JOINT RECOMMENDATION OF SOUTHERN CALIFORNIA EDISON COMPANY,

DIVISION OF RATEPAYER ADVOCATES, CALIFORNIA COGENERATION COUNCIL,

AND COGENERATORS OF SOUTHERN CALIFORNIA

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

The testimony of the Southern California Edison Company ("Edison"), the Division of Ratepayer Advocates ("DRA"), the California Cogeneration Council ("CCC") and the Cogenerators of Southern California ("CSC"), (collectively "the parties") supports a range of forecast revenue requirements and a range of incremental energy rates ("IER").[1]

Based on a perceived interest among the parties in reaching a compromise, DRA reviewed the IER and revenue requirement recommendations submitted by the parties.[2] Based upon certain assumptions advocated by each of the parties, DRA made a compromise proposal. This proposal was presented to CSC, CCC, Edison and other interested participants.

By this joint recommendation, the parties agree to jointly recommend, and will not contest, the adoption of an ECAC revenue increase of $287.5 million[3] and an annual average avoided cost IER of 9,531 Btu/kWh as a compromise of the various positions advocated by the parties. Attached as Appendix B to this Exhibit is a summary of the change in ECAC revenues.

1. <u>Time Differentiated Incremental Energy Rates</u>

The parties agree that the annual average IER of 9,531 Btu/kWh should be time differentiated for the Forecast Period as follows:

---

[1] <u>See</u> Exhibits 1, 2, 4, 5, 7, 8, and 9.

[2] A summary of the IER and ECAC Revenue proposals of the parties is set forth in Appendix A.

[3] This recommended ECAC revenue increase is based on an Energy Reliability Index ("ERI") of 0.0. By virtue of this joint recommendation, the parties are not abandoning any positions or arguments regarding the appropriate ERI values to be determined in this proceeding. If the Commission adopts an ERI greater than 0.0, the revenue change recommended herein should be increased solely to reflect the impact of the adopted ERI on capacity payments to as-available QFs whose capacity payments are dependent upon an ERI value.

	Peak	Mid	Off	Super Off-Peak
Summer	13,574	8,402	8,620	N/A
Winter	N/A	10,586	9,562	8,128

2. Determination Of Qualifying Facility Payments

For the purposes of determining QF payments, particularly through avoided cost postings, the parties agree that Edison shall, until otherwise directed by the Commission, determine gas transportation costs using the gas volume adopted by the Commission in the most recent Southern California Gas Company ("SoCal") Annual Cost Allocation Proceeding ("ACAP") beginning with Application No. 90-03-018. Moreover, the parties recommend that the Commission's decision in this proceeding adopt the principle that, until otherwise directed by the Commission, Edison's QF payments shall be determined using the gas transportation costs based on the gas volumes adopted by the Commission in the SoCal ACAP decision in effect on the first day of each QF payment period.

3. Ratemaking Treatment of ECAC Expenses

The parties recommend that if the Commission, in OII 90-08-006, reinstates the Annual Energy Rate ("AER") or adopts a successor procedure, 100 percent of the expenses and revenues subject to the AER or successor procedure shall be recorded in the Energy Cost Adjustment Account until ECAC rates reflecting a new forecast of fuel and purchased power expense has been made effective by the Commission in a subsequent annual ECAC filing.

4. Scope and Limitations

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 ECAC revenue change and IER recommendations contained in this exhibit. The avoided cost IERs adopted in this proceeding are to be used solely for the purpose of determining payments to QFs. However, this joint recommendation shall not be construed to be acceptance of: (a) the methodology or assumptions underlying this joint recommendation or any parties' estimate of Edison's ECAC revenue requirement or IER presented in this proceeding; or (b) any of the resource assumptions, arguments, or positions taken by parties in this proceeding.

Except for the principle set forth in Paragraph No. 2 above, none of the principles or the methodologies

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underlying this joint recommendation shall be deemed by the Commission or any other entity as precedent in any proceeding or any litigation except in order to implement in this proceeding the recommendations contained herein. The parties expressly reserve the right to advocate different principles or methodologies from those underlying this joint recommendation in other proceedings.

The parties understand and agree that this joint recommendation 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 basis for the final ECAC revenue change and the final IER for the Forecast Period.

5. Execution

The undersigned, on behalf of the parties they represent in this proceeding, hereby agree to abide by the conditions and recommendations set forth herein.

Dated this 18th day of September, 1990.

SOUTHERN CALIFORNIA EDISON COMPANY	CALIFORNIA COGENERATION COUNCIL
/s/ Bruce A. Reed	/s/ Jerry R. Bloom
DIVISION OF RATEPAYER ADVOCATES	COGENERATORS OF SOUTHERN CALIFORNIA
/s/ Kathleen C. Maloney	/s/ Michael P. Alcantar

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IER AND ECAC REVENUE PROPOSALS OF THE PARTIES

The following reflects the current IER and ECAC revenue[1] proposals of the parties:

	Proposed IER Btu/kWh	Proposed ECAC Revenue Increase ($ million)
Edison	9,347	321.3
DRA	9,345	175.6
CCC[2]	9,662/9,515	Not available
CSC[3]	9,666/9,792	155.2/306.4

1 In addition to the ECAC revenue increase, Edison has requested increases in ERABF revenues of $182.7 million and LIS revenues of $6.2 million and a $15.7 million decrease in MAABF revenues. See Additional Direct Testimony of Peter S. Goeddel contained in Exhibit 14.

2 CCC proposed two separate IERs to be used when either gas or oil is the marginal fuel. CCC submitted no proposed revenue requirement in its testimony.

3 CSC proposed two separate IERs and revenue requirements based upon DRA's and Edison's forecasted gas prices, respectively.

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APPENDIX B

JOINT RECOMMENDATION
CHANGE IN ECAC REVENUES

		(000's of $)
1.	Forecasted Jurisdictionalized Energy Cost	2,971,878
2.	ECAC Balancing Account Undercollection	259,111 [1]
3.	Forecast ECAC Costs to be amortized	3,230,989
4.	Uncollectibles and Franchise Fee Factor	1.00953
5.	Estimated ECAC Revenue Requirement (Line 3 multiplied by Line 4)	3,261,780
6.	Less Present Rate Revenues	2,974,244 [2]
7.	Estimated Change in ECAC revenues	287,536

1 Forecast December 31, 1990, ECAC Balancing Account balance based on recorded data through July 31, 1990.

2 Calculated using Forecasted sales of 70,971.6 GWh (includes adjusted for DE discount).

(END OF APPENDIX B)

SOUTHERN CALIFORNIA EDISON COMPANY

REVENUE REQUIREMENT CONSOLIDATION
EFFECTIVE JANUARY 1, 1991
(Thousands Of Dollars)

Line No.	Revenue Component	Present Rate Revenue 2/	Revenue Change	Adopted Revenue Requirement	Average Rate (Cents/kWh) 1/
1.	BASE RATES				
2.	Previously Authorized Rates	3,863,004.0	(157,719.5)	3,705,284.5	---
3.	1991 Modified Attrition		202,787.0	202,787.0	---
4.	Payroll Taxes		1,733.0	1,733.0	---
5.	1991 Cost of Capital		1,091.0	1,091.0	---
6.	Demand Side Management		6,356.0	6,356.0	---
7.	Intervenor Compensation		104.8	104.8	---
8.	Subtotal Base Rate Revenues	3,863,004.0	54,352.3	3,917,356.3	5.517
9.	MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC)				
10.	SONGS 2 and 3 Pre-COD	8,516.6	(466.6)	8,050.0	0.011
11.	SONGS 2 and 3 Post-COD	45,840.7	(2,565.6)	44,275.1	0.063
12.	High Voltage DC Transmission Line	12,065.0	(660.8)	11,404.2	0.016
13.	Balsam Meadow	8,516.6	(8,516.6)	0.0	0.000
14.	Devers-Valley-Serrano	3,548.5	(3,548.5)	0.0	0.000
15.	Subtotal MAAC Rate Revenues	79,487.4	(15,758.1)	63,729.3	0.090
16.	ENERGY COST ADJUSTMENT CLAUSE (ECAC)				
17.	Fuel And Purchased Power	2,684,870.2	315,329.8	3,000,200.0	---
18.	Balancing Account	288,140.6	(26,560.6)	261,580.0	---
19.	Subtotal ECAC Rate Revenues	2,973,010.8	288,769.2	3,261,780.0	4.594
20.	ANNUAL ENERGY RATE (AER)	0.0	0.0	0.0	0.000
21.	ELECTRIC REVENUE ADJUSTMENT BILLING FACTOR (ERABF)				
22.	Balancing Account	(149,038.6)	153,455.6	4,417.0	---
23.	Palo Verde Unit 1	54,647.4	(2,724.2)	51,923.2	---
24.	Palo Verde Unit 2	55,357.1	(2,483.0)	52,874.1	---
25.	SMUD	(31,227.1)	31,227.1	0.0	---
26.	Off-System Sales	0.0	(49,116.0)	(49,116.0)	---
27.	Subtotal ERABF Rate Revenues	(70,261.2)	130,359.5	60,098.3	0.085
28.	LOW-INCOME RATEPAYER ASSISTANCE (LIRA) PROGRAM				
29.	Low-Income Discount Rate (LID)	(22,927.4)	(2,642.5)	(25,569.9)	---
30.	Low-Income Surcharge (LIS)	19,294.4	8,868.5	28,162.9	---
31.	Subtotal LIRA Rate Revenues	(3,633.0)	6,226.0	2,593.0	0.004
32.	TOTAL	6,841,608.0	463,948.9	7,305,556.9	10.290
33.	PERCENTAGE INCREASE		6.8%		

1/ Based on 71,000 GWh sales adopted in A. 90-06-001.
2/ Based on rate levels effective September 19, 1990.

SOUTHERN CALIFORNIA EDISON COMPANY

JANUARY 1, 1991 REVENUE CHANGE BY PROCEEDING

(Thousands of Dollars)

Line No.	Proceeding	Reference	Revenue Requirement	Present Rate Revenues 1/	Revenue Change (2) - (3)
		(1)	(2)	(3)	(4)
1.	ECAC	A. 90-06-001			
2.	Energy Cost Adjustment		3,261,780.0	2,973,010.8	288,769.2
3.	Billing Factor (ECABF)				
4.	Electric Revenue Adjustment		56,340.2	(125,618.3)	181,958.5
5.	Billing Factor (ERABF)				
6.	Palo Verde Unit 2 (ERABF)		52,874.1	55,357.1	(2,483.0)
7.	(Advice 873-E-A)				
8.	Major Additions Adjustment		63,729.3	79,487.4	(15,758.1)
9.	Billing Factor (MAABF)				
10.	Low Income Ratepayer		2,593.0	(3,633.0)	6,226.0
11.	Assistance (LIRA)				
12.	Total ECAC		3,437,316.6	2,978,604.0	458,712.6
13.	Modified Attrition	A. 90-03-048			
14.	Beginning ALBRR (2/1/90)		3,687,468.9	3,841,140.4	(153,671.5)
15.	Modified Attrition		202,787.0	0.0	202,787.0
16.	ERABF		(49,116.0)	0.0	(49,116.0)
17.	Payroll Taxes (Advice 889-E)		1,733.0	0.0	1,733.0
18.	Total Modified Attrition		3,842,872.9	3,841,140.4	1,732.5
19.	Cost of Capital (Advice 890-E)	A. 90-05-016	1,091.0	0.0	1,091.0
20.	Palo Verde Unit 2 (Base Rates)	Advice 873-E-A	20,190.6	21,863.6	(1,673.0)
21.	Demand Side Management				
22.	Advice 879-E		(2,375.0)	0.0	(2,375.0)
23.	Advice 885-E		6,356.0	0.0	6,356.0
24.	Total Demand Side Management		3,981.0	0.0	3,981.0
25.	Intervenor Compensation	Advice 886-E	104.8	0.0	104.8
26.	Total		7,305,556.9	6,841,608.0	463,948.9

1/ Based on rate levels effective September 19, 1990.

SOUTHERN CALIFORNIA EDISON COMPANY

UNIT MARGINAL COST

ESCALATED MARGINAL DEMAND AND CUSTOMER COSTS

Marginal Demand Costs: ($/kW-year) 1/

Generation	$78.08
Transmission	$37.20
Distribution	$58.68 (Secondary)
	$50.64 (Primary)

Marginal Customer Costs: ($/Customer-Year) 1/

Domestic	$ 48.82
GS-SP/TP	48.43
GS-2	237.85
PA-1	144.44
PA-2	240.90
TOU-8 (Secondary)	1,509.03
TOU-8 (Primary)	2,404.53
TOU-8 (Subtransmission)	2,404.53

Marginal Energy Costs:

		Btu/kWh	Cents/kWh 2/
Summer:	On-Peak	12,121	4.08
	Mid-Peak	9,579	3.29
	Off-Peak	8,798	3.04
Winter:	Mid-Peak	10,869	3.69
	Off-Peak	8,900	3.08

1/ Adopted unit marginal capacity and customer costs are based on D.87-12-066, p. 246, and Appendix G levels, adjusted for escalation in Implicit Price Deflator 1989-1991.

2/ Based on the $3.12/MMBtu gas price plus .3 cents/kWh variable O&M (D.87-12-066, Appendix G, Table 6), at generation level.

SOUTHERN CALIFORNIA EDISON COMPANY

MARGINAL COST REVENUE RESPONSIBILITY

Forecast Period
January 1, 1991 - December 31, 1991

($ Thousands)

	ENERGY	GENERATION	TRANSMISSION	DISTRIBUTION	CUSTOMER	TOTAL
DOMESTIC	816,172	449,723	205,823	407,775	171,277	2,050,771
GS-SP/TP	164,100	115,236	51,501	88,195	18,133	437,165
GS-2	745,484	384,292	175,916	347,838	32,997	1,686,527
TOU-8/SEC	294,375	130,329	58,068	98,472	3,173	584,417
TOU-8/PRI	217,574	81,097	36,461	53,469	1,677	390,277
TOU-8/SUB	254,512	79,050	35,658	0	315	369,534
AG & PUMPING	75,947	32,872	15,448	34,826	4,091	163,183
ST.& AREA LGT 1/	15,305	451	504	3,573	3,242	23,075
TOTAL	2,583,468	1,273,050	579,378	1,034,147	234,905	5,704,948

1/ Excludes Street Light Facility Costs.

SOUTHERN CALIFORNIA EDISON COMPANY
JANUARY 1, 1991 COMBINED RATE CHANGE

REVENUE ALLOCATION 1/ 2/

LINE NO.	RATE GROUP	SALES (GWH)	PRESENT RATE REVENUE W/ LIRA ($M)	PRESENT RATE REVENUE W/O LIRA ($M)	MARGINAL COST REVENUE (%)	100% EPMC REVENUE ALLOCATION W/O LIRA ($M)	100% EPMC REVENUE ALLOCATION W/LIRA ($M)	CHANGE FROM PRESENT RATE REVENUES W/O LIRA ($M)	CHANGE FROM PRESENT RATE REVENUES W/O LIRA (%)	CHANGE FROM PRESENT RATE REVENUES W/LIRA ($M)	CHANGE FROM PRESENT RATE REVENUES W/LIRA (%)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	DOMESTIC	22,318.2	2,374,851.3	2,391,966.2	35.947228%	2,612,129	2,595,043	220,163	9.2%	220,192	9.3%
2	LIGHTING - SMP:										
3	GS-SP/TP	4,393.7	532,014.2	530,784.1	7.662903%	556,830	558,626	26,045	4.9%	26,612	5.0%
4	GS-2	20,204.7	2,012,180.2	2,005,522.9	29.562525%	2,148,198	2,156,456	141,675	7.1%	144,276	7.2%
5	TOTAL	24,598.4	2,544,194	2,537,307	37.225434%	2,705,028	2,715,082	167,721	6.6%	170,888	6.7%
6	LARGE POWER:										
7	TOU-8-SEC	8,006.4	717,725.2	715,483.3	10.244035%	744,390	747,662	28,906	4.0%	29,935	4.2%
8	TOU-8-PRI	6,094.5	486,002.4	484,316.9	6.841025%	497,108	499,558	12,791	2.6%	13,555	2.8%
9	TOU-8-SUB	7,445.5	448,500.2	445,417.0	6.477429%	470,687	473,727	24,270	5.4%	25,227	5.6%
10	TOTAL	21,546.4	1,652,228	1,645,217	23.562489%	1,712,185	1,720,958	65,967	4.0%	68,729	4.2%
11	AG & PUMPING	2,085.2	201,897.0	201,313.0	2.860376%	207,878	205,730	6,565	3.3%	6,833	3.4%
12	ST & AREA LGT	450.8	68,437.6	68,437.6	0.404473%	65,744	65,744	(2,693)	-3.9%	(2,693)	-3.9%
13	TOTAL	70,999.0	6,841,608	6,845,241	100.000000%	7,302,964	7,305,557	457,723	6.7%	453,949	6.8%

1/ REVENUE ALLOCATION METHODOLOGY EXCLUDES TOU-METERING AND FACILITIES CHARGES AS FOLLOWS ($M):

LSMP	18
AG & PUMPING	27
ST & AREA LIGHTING	35,353
TOTAL	35,398

2/ BASED ON A $3.12/MMBTU GAS PRICE

A.90-06-001 /ALJ/BDP/dk *

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE $/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	TIME-RELATED DEMAND CHARGE ($/kW) Winter	NON-TIME-RELATED DEMAND CHARGE ($/kW) 1/ Annual	ENERGY CHARGE (¢/kWh) BASE RATE Summer	BASE RATE Winter/Annual	ECAC Summer	ECAC Winter	2/ Other Offsets	TOTAL OFFSETS Summer	TOTAL OFFSETS Winter	TOTAL RATES 3/ Summer	TOTAL RATES 3/ Winter
DOMESTIC: *	D: BL / NBL	0.10 4/				13/	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-D: ON / MID / OFF	0.10 4/ 5/					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Baseline Credit =	3.959 c/kWh													
	D-LI: 7/ BL / NBL	0.085 4/					[illegible]	[illegible]	[illegible]	[illegible]	6/ [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LIGHTING - SMALL & MEDIUM POWER:	GS-1P:	0.33						5.054	5.743	5.743	0.175	5.918	5.918	11.002	11.002
	GS-SP:	0.33						5.084	5.743	5.743	0.175	5.918	5.918	11.002	11.002
	GS-2: 1ST BLK / 2ND BLK **		36.25	10.00	3.15			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TC-1	0.30						4.703	5.367	5.367	0.175	5.542	5.542	10.245	10.245
	TOU-GS: ON / MID / OFF		36.25 8/	[illegible]	[illegible]	3.15		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LARGE POWER: ***	TOU-8-SEC: ON / MID / OFF		287.00	[illegible]	[illegible]	3.10		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-8-PRI: ON / MID / OFF		283.45	[illegible]	[illegible]	2.20		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-8-SUB: ON / MID / OFF		279.25	[illegible]	[illegible]	0.25		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
AGRICULTURAL & PUMPING:	PA-1:		11.40	1.15 9/	1.15 9/			4.233	[illegible]	[illegible]	0.175	[illegible]	[illegible]	[illegible]	[illegible]
	PA-2: 1ST BLK / 2ND BLK **		22.85	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-AGRP-2: ON / MID / OFF		11.40					[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-PA-1: ON / MID / OFF		11.40	[illegible] 10/	3.15 10/			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-PA (RATE A): ON / MID / OFF		34.25 11/	1.15 9/	1.15 9/			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-PA (RATE B): ON / MID / OFF		34.25 11/	[illegible]	[illegible]	1.30		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-PA-3 (RATE A): ON / MID / OFF		34.25 11/	1.15 9/	1.15 9/			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-PA-3 (RATE B): ON / MID / OFF		34.25 11/	[illegible]	[illegible]	1.30		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-PA-4 (RATE A): ON / MID / OFF		34.25 11/	1.15 9/	1.15 9/			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-PA-4 (RATE B): ON / MID / OFF		34.25 11/	[illegible]	[illegible]	1.30		3.751 / 3.751 / 3.751	11.207 / [illegible] / 1.074	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	TOU-PA-5 (>35KW MIN BILL): 11/ ON / MID / OFF		22.85 12/	[illegible] / 0.00 / 0.00	[illegible]	1.30		3.722 / 3.722 / 3.722	4.053 / [illegible] / 2.538	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

1/ Maximum Demand Charge to

2/ Other Offsets = ... (c/kWh)

ALE	CMSF	ERABF	DAABF
0.050	0.050	0.085	0.090

3/ The following charges are in addition to total rates: LIS = 0.041 c/kWh PUCRF = 0.012 c/kWh
4/ Minimum Charge
5/ Additional meter charge at $3.15 /customer/day.
6/ Low Income Discount of (1.515)c/kWh for BL; (2.103)c/kWh for NBL is included.
7/ LIS of 0.041 c/kWh does not apply to D-LI.
8/ Additional meter charge at $7.00 /customer/month.
9/ Connected load charge per HP per month
10/ Per kVA per month
11/ Additional meter charge at $6.00 /customer/month
12/ Summer monthly minimum charge = $26.15 /kW of Contract Demand
Winter monthly minimum charge = $10.15 /kW of Contract Demand
13/ Annualized Base Rate used to determine when minimum charge is applicable= 6.347 c/kWh
* Domestic Seasonal Schedule DS: Summer season premium = 2.050 c/kWh
Winter season discount = 2.000 c/kWh
** First 300 kWh/kW
*** Subject to Rate Limiter: Ave Summer SEC = 0.15773 PRI = 0.15773 [illegible] = 0.69065
Summer On-pk SEC = 0.91535 PRI = 0.91882
S[illegible] Schedule S : kW/Standby kW) SEC = $3.10 PRI = $2.23 SUB = [illegible]0.25
RTP-2 Base Rate = 4.452 Cents/kWh

APPENDIX C
Page 6

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE ¢/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	TIME-RELATED DEMAND CHARGE ($/kW) Winter	NON-TIME-RELATED DEMAND CHARGE ($/kW) 1/ Annual	ENERGY CHARGE (¢/kWh) Annual Base Rate	ECABF Summer	ECABF Winter	2/ Other Offsets	TOTAL OFFSETS Summer	TOTAL OFFSETS Winter	TOTAL RATES 3/ Summer	TOTAL RATES 3/ Winter
LARGE POWER:	I-5-A SEC:	287.00												
	ON			15.20	-	3.10	1.622	8.234	-	0.175	8.409	-	10.031	-
	MID			2.45	0.00		1.622	5.950	7.055	0.175	6.125	7.230	7.747	8.852
	OFF			0.00	0.00		1.622	0.703	0.703	0.175	0.878	0.878	2.500	2.500
	I-5-A PRI:	282.43												
	ON			14.65	-	2.20	1.550	7.326	-	0.175	7.501	-	9.051	-
	MID			2.20	0.00		1.550	5.235	6.280	0.175	5.410	6.455	6.960	8.005
	OFF			0.00	0.00		1.550	0.775	0.775	0.175	0.950	0.950	2.500	2.500
	I-5-A SUB:	279.25												
	ON			12.55	-	0.25	1.352	5.266	-	0.175	5.441	-	6.793	-
	MID			1.95	0.00		1.352	3.623	4.445	0.175	3.798	4.620	5.150	5.972
	OFF			0.00	0.00		1.352	0.973	0.973	0.175	1.148	1.148	2.500	2.500
	I-5-B SEC:	287.00												
	ON			15.20	-	3.10	3.122	8.234	-	0.175	8.409	-	11.531	-
	MID			2.45	0.00		3.122	5.950	7.055	0.175	6.125	7.230	9.247	10.352
	OFF			0.00	0.00		3.122	1.703	1.703	0.175	1.878	1.878	5.000	5.000
	OFF						3.122	(0.797)	(0.797)	0.175	(0.622)	(0.622)	2.500	2.500
	I-5-B PRI:	282.43												
	ON			14.65	-	2.20	3.050	7.326	-	0.175	7.501	-	10.551	-
	MID			2.20	0.00		3.050	5.235	6.280	0.175	5.410	6.455	8.460	9.505
	OFF			0.00	0.00		3.050	1.775	1.775	0.175	1.950	1.950	5.000	5.000
	OFF						3.050	(0.725)	(0.725)	0.175	(0.550)	(0.550)	2.500	2.500
	I-5-B SUB:	279.25												
	ON			12.55	-	0.25	2.852	5.266	-	0.175	5.441	-	8.293	-
	MID			1.95	0.00		2.852	3.623	4.445	0.175	3.798	4.620	6.650	7.472
	OFF			0.00	0.00		2.852	1.973	1.973	0.175	2.148	2.148	5.000	5.000
	OFF						2.852	(0.527)	(0.527)	0.175	(0.352)	(0.352)	2.500	2.500
	I-6-A SEC:	287.00												
	ON			10.65	-	3.10	2.664	7.994	-	0.175	8.169	-	10.833	-
	MID			1.70	0.00		2.664	5.868	6.950	0.175	6.043	7.125	8.707	9.789
	OFF			0.00	0.00		2.664	1.703	1.687	0.175	1.878	1.862	4.542	4.526
	I-6-A PRI:	282.43												
	ON			10.25	-	2.20	2.592	7.101	-	0.175	7.276	-	9.868	-
	MID			1.50	0.00		2.592	5.163	6.201	0.175	5.338	6.376	7.930	8.968
	OFF			0.00	0.00		2.592	1.775	1.759	0.175	1.950	1.934	4.542	4.526
	I-6-A SUB:	279.25												
	ON			8.30	-	0.25	2.394	5.097	-	0.175	5.272	-	7.666	-
	MID			1.30	0.00		2.394	3.600	4.408	0.175	3.775	4.583	6.169	6.977
	OFF			0.00	0.00		2.394	1.973	1.957	0.175	2.148	2.132	4.542	4.526
	I-6-B SEC:	287.00												
	ON			11.20	-	3.10	2.721	8.024	-	0.175	8.199	-	10.920	-
	MID			1.83	0.00		2.721	5.878	6.963	0.175	6.053	7.138	8.774	9.859
	OFF			0.00	0.00		2.721	1.703	1.689	0.175	1.878	1.864	4.599	4.585
	I-6-B PRI:	282.43												
	ON			10.83	-	2.20	2.649	7.129	-	0.175	7.304	-	9.953	-
	MID			1.60	0.00		2.649	5.172	6.211	0.175	5.347	6.386	7.996	9.035
	OFF			0.00	0.00		2.649	1.775	1.761	0.175	1.950	1.936	4.599	4.585
	I-6-B SUB:	279.25												
	ON			8.85	-	0.25	2.451	5.118	-	0.175	5.293	-	7.744	-
	MID			1.35	0.00		2.451	3.602	4.412	0.175	3.777	4.587	6.228	7.038
	OFF			0.00	0.00		2.451	1.973	1.959	0.175	2.148	2.134	4.599	4.585

1/ Maximum Demand Charge kW

2/ Other Offsets =	FER	CLRASF	ERASF	RRASF
(¢/kWh)	0.000	0.000	0.085	0.090

3/ The following charges are in addition to total rates: EIS = 0.041 ¢/kWh
PUCRF = 0.012 ¢/kWh

RATE LEVEL SUMMARY

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE ¢/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	Spring/Fall	Winter	NON-TIME-RELATED DEMAND CHARGE 1/ ($/kW) Annual	ENERGY CHARGE (¢/kWh) Base Rate	ECABF Summer	ECABF Spring/Fall	ECABF Winter	4/ Other Offsets	TOTAL OFFSETS Summer	TOTAL OFFSETS Spring/Fall	TOTAL OFFSETS Winter	TOTAL RATES 5/ Summer	TOTAL RATES 5/ Spring/Fall	TOTAL RATES 5/ Winter
LIGHTING - SMALL & MEDIUM POWER:	TOU-GS-SOP:		36.25 2/															
	ON			39.85	-	-	3.15	2.772	8.164	-	-	0.175	8.339	-	-	11.111	-	-
	MID			1.05	0.55	0.55		2.772	8.164	5.478	6.319	0.175	8.339	5.653	6.494	11.111	8.425	9.266
	OFF			0.00	0.00	0.00		2.772	4.382	4.875	4.875	0.175	4.557	5.050	5.050	7.329	7.822	7.822
	OFF			0.00	0.00	0.00		2.772	0.553	0.553	0.553	0.175	0.728	0.728	0.728	3.500	3.500	3.500
LARGE POWER:	TOU-8-SOP-SEC:		287.00															
	ON			37.85	-	-	3.10	2.143	7.805	-	-	0.175	7.980	-	-	10.123	-	-
	MID			1.00	0.50	0.50		2.143	7.805	5.339	6.103	0.175	7.980	5.514	6.278	10.123	7.657	8.421
	OFF			0.00	0.00	0.00		2.143	4.343	4.781	4.781	0.175	4.518	4.956	4.956	6.661	7.099	7.099
	OFF			0.00	0.00	0.00		2.143	1.182	1.182	1.182	0.175	1.357	1.357	1.357	3.500	3.500	3.500
	TOU-8-SOP-PRI:		282.43															
	ON			37.25	-	-	2.20	1.940	6.947	-	-	0.175	7.122	-	-	9.062	-	-
	MID			0.55	0.50	0.50		1.940	6.947	4.758	5.444	0.175	7.122	4.933	5.619	9.062	6.873	7.559
	OFF			0.00	0.00	0.00		1.940	3.854	4.266	4.266	0.175	4.029	4.441	4.441	5.969	6.381	6.381
	OFF			0.00	0.00	0.00		1.940	1.385	1.385	1.385	0.175	1.560	1.560	1.560	3.500	3.500	3.500
	TOU-8-SOP-SUB:		279.25															
	ON			35.15	-	-	2.25	1.987	5.812	-	-	0.175	5.987	-	-	7.974	-	-
	MID			0.95	0.45	0.45		1.987	5.812	3.902	4.508	0.175	5.987	4.077	4.683	7.974	6.064	6.670
	OFF			0.00	0.00	0.00		1.987	3.114	3.468	3.468	0.175	3.289	3.643	3.643	5.276	5.630	5.630
	OFF			0.00	0.00	0.00		1.987	1.338	1.338	1.338	0.175	1.513	1.513	1.513	3.500	3.500	3.500
	TOU-8-SOP-1-A-SEC:		287.00															
	ON			27.65	-	-	3.10	1.986	7.616	-	-	0.175	7.791	-	-	9.777	-	-
	MID			0.65	0.35	0.35		1.986	7.616	5.276	6.036	0.175	7.791	5.451	6.211	9.777	7.437	8.197
	OFF			0.00	0.00	0.00		1.986	4.182	4.717	4.726	0.175	4.357	4.892	4.901	6.343	6.878	6.887
	OFF			0.00	0.00	0.00		1.986	1.182	1.182	1.182	0.175	1.357	1.357	1.357	3.343	3.343	3.343
	TOU-8-SOP-1-A-PRI:		282.43															
	ON			26.45	-	-	2.20	1.783	6.863	-	-	0.175	7.038	-	-	8.821	-	-
	MID			0.65	0.35	0.35		1.783	6.863	4.702	5.383	0.175	7.038	4.877	5.558	8.821	6.660	7.341
	OFF			0.00	0.00	0.00		1.783	3.813	4.199	4.208	0.175	3.988	4.374	4.383	5.771	6.157	6.166
	OFF			0.00	0.00	0.00		1.783	1.385	1.385	1.385	0.175	1.560	1.560	1.560	3.343	3.343	3.343
	TOU-8-SOP-1-A-SUB:		279.25															
	ON			24.85	-	-	0.25	1.830	5.739	-	-	0.175	5.914	-	-	7.744	-	-
	MID			0.65	0.30	0.30		1.830	5.739	3.855	4.457	0.175	5.914	4.030	4.632	7.744	5.860	6.462
	OFF			0.00	0.00	0.00		1.830	3.072	3.411	3.419	0.175	3.247	3.586	3.594	5.077	5.416	5.424
	OFF			0.00	0.00	0.00		1.830	1.338	1.338	1.338	0.175	1.513	1.513	1.513	3.343	3.343	3.343
	TOU-8-SOP-1-B-SEC:		287.00															
	ON			28.35	-	-	3.10	2.005	7.639	-	-	0.175	7.814	-	-	9.819	-	-
	MID			0.70	0.35	0.35		2.005	7.639	5.284	6.045	0.175	7.814	5.459	6.220	9.819	7.464	8.225
	OFF			0.00	0.00	0.00		2.005	4.207	4.726	4.734	0.175	4.382	4.901	4.909	6.387	6.906	6.914
	OFF			0.00	0.00	0.00		2.005	1.182	1.182	1.182	0.175	1.357	1.357	1.357	3.362	3.362	3.362
	TOU-8-SOP-1-B-PRI:		282.43															
	ON			27.75	-	-	2.20	1.802	6.874	-	-	0.175	7.049	-	-	8.851	-	-
	MID			0.65	0.35	0.35		1.802	6.874	4.709	5.391	0.175	7.049	4.884	5.566	8.851	6.686	7.368
	OFF			0.00	0.00	0.00		1.802	3.820	4.208	4.215	0.175	3.995	4.383	4.390	5.797	6.185	6.192
	OFF			0.00	0.00	0.00		1.802	1.385	1.385	1.385	0.175	1.560	1.560	1.560	3.362	3.362	3.362
	TOU-8-SOP-1-B-SUB:		279.25															
	ON			26.15	-	-	0.25	1.849	5.749	-	-	0.175	5.924	-	-	7.773	-	-
	MID			0.70	0.30	0.30		1.849	5.749	3.861	4.464	0.175	5.924	4.036	4.639	7.773	5.885	6.488
	OFF			0.00	0.00	0.00		1.849	3.078	3.419	3.426	0.175	3.253	3.594	3.601	5.102	5.443	5.450
	OFF			0.00	0.00	0.00		1.849	1.338	1.338	1.338	0.175	1.513	1.513	1.513	3.362	3.362	3.362
AGRICULTURAL & PUMPING:	TOU-PA-SOP:																	
	ON		24.25 3/	37.65	-	-	1.30	1.660	8.257		-	0.175	8.432		-	10.092		-
	OFF			0.00	0.00	0.00		1.660	5.486		5.696	0.175	5.661		5.871	7.321		7.531
	OFF			0.00	0.00	0.00		1.660	1.655		1.655	0.175	1.840		1.840	3.500		3.500

1/ Maximum Demand Charge kW
2/ Additional Meter charge at $7.00 /customer/month.
3/ Additional Meter charge at $5.00 /customer/month.

	AER	CLRABF	ERABF	BRABF
4/ Other Offsets = (¢/kWh)	0.000	0.000	0.085	0.090

5/ The following charges are in addition to total rates: LRS= 0.041 ¢/kWh
PUCRF = 0.012 ¢/kWh

SOUTHERN CALIFORNIA EDISON COMPANY

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A - ALL NIGHT SERVICE 1991

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	0.02670	0.03049	35.535	0.94878	1.08346	6.24	8.27
202	2,500	0.02670	0.03049	69.690	1.86072	2.12485	6.24	10.23
327	4,000	0.02670	0.03049	112.815	3.01216	3.43973	6.25	12.70
448	6,000	0.02670	0.03049	154.560	4.12675	4.71253	6.20	15.04
MERCURY VAPOR LAMPS								
100	4,000	0.02670	0.03049	45.195	1.20671	1.37800	6.23	8.81
175	7,900	0.02670	0.03049	74.520	1.98968	2.27211	6.20	10.46
250	12,000	0.02670	0.03049	103.845	2.77266	3.16623	6.23	12.17
400	21,000	0.02670	0.03049	163.530	4.36625	4.98603	6.61	15.96
700	41,000	0.02670	0.03049	277.035	7.39683	8.44680	6.67	22.51
1,000	55,000	0.02670	0.03049	391.575	10.45505	11.93912	6.67	29.06
HIGH PRESSURE SODIUM								
50	4,000	0.02670	0.03049	20.010	0.53427	0.61010	6.23	7.37
70	5,800	0.02670	0.03049	28.635	0.76455	0.87308	6.20	7.84
100	9,500	0.02670	0.03049	40.365	1.07775	1.23073	6.20	8.51
150	16,000	0.02670	0.03049	66.585	1.77782	2.03018	6.24	10.05
200	22,000	0.02670	0.03049	84.870	2.26603	2.58769	6.60	11.45
250	27,500	0.02670	0.03049	107.985	2.88320	3.29246	6.62	12.80
400	50,000	0.02670	0.03049	167.325	4.46758	5.10174	6.70	16.27
LOW PRESSURE SODIUM								
35	4,800	0.02670	0.03049	21.735	0.58032	0.66270	6.77	8.01
55	8,000	0.02670	0.03049	28.380	0.77377	0.88360	6.77	8.43
90	13,500	0.02670	0.03049	45.195	1.20671	1.37800	7.70	10.28
135	22,500	0.02670	0.03049	62.790	1.67649	1.91447	7.97	11.56
180	33,000	0.02670	0.03049	79.005	2.10943	2.40886	7.72	12.24

SOUTHERN CALIFORNIA EDISON COMPANY

LS-1
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B - MIDNIGHT SERVICE 1991

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	0.03415	0.03049	17.943	0.61275	0.54708	6.24	7.40
202	2,500	0.03415	0.03049	35.188	1.20167	1.07288	6.24	8.51
327	4,000	0.03415	0.03049	56.963	1.94529	1.73680	6.25	9.93
448	6,000	0.03415	0.03049	78.042	2.66513	2.37950	6.20	11.24
MERCURY VAPOR LAMPS								
100	4,000	0.03415	0.03049	22.820	0.77930	0.69578	6.23	7.71
175	7,900	0.03415	0.03049	37.627	1.28496	1.14725	6.20	8.63
250	12,000	0.03415	0.03049	52.434	1.79062	1.59871	6.23	9.62
400	21,000	0.03415	0.03049	82.571	2.81980	2.51759	6.61	11.95
700	41,000	0.03415	0.03049	139.883	4.77700	4.26503	6.67	15.71
1,000	55,000	0.03415	0.03049	197.717	6.75204	6.02839	6.67	19.45
HIGH PRESSURE SODIUM								
50	4,000	0.03415	0.03049	10.104	0.34505	0.30807	6.23	6.88
70	5,800	0.03415	0.03049	14.459	0.49377	0.44085	6.20	7.13
100	9,500	0.03415	0.03049	20.381	0.69601	0.62142	6.20	7.52
150	16,000	0.03415	0.03049	33.621	1.14816	1.02510	6.24	8.41
200	22,000	0.03415	0.03049	42.853	1.46343	1.30659	6.60	9.37
250	27,500	0.03415	0.03049	54.525	1.86203	1.66247	6.62	10.14
400	50,000	0.03415	0.03049	84.487	2.88523	2.57601	6.70	12.16
LOW PRESSURE SODIUM								
35	4,800	0.03415	0.03049	10.975	0.37480	0.33463	6.77	7.48
55	8,000	0.03415	0.03049	14.633	0.49972	0.44616	6.77	7.72
90	13,500	0.03415	0.03049	22.820	0.77930	0.69578	7.70	9.18
135	22,500	0.03415	0.03049	31.704	1.08269	0.96665	7.97	10.02
180	33,000	0.03415	0.03049	39.892	1.36231	1.21631	7.72	10.30

SOUTHERN CALIFORNIA EDISON COMPANY

LS-2
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A - MULTIPLE SERVICE/ALL NIGHT 1991

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	0.02670	0.03049	35.535	0.94878	1.08346	0.79	2.82
202	2,500	0.02670	0.03049	69.690	1.86072	2.12485	0.79	4.78
327	4,000	0.02670	0.03049	112.815	3.01216	3.43973	0.79	7.24
448	6,000	0.02670	0.03049	154.560	4.12675	4.71253	0.79	9.63
690	10,000	0.02670	0.03049	238.050	6.35594	7.25814	0.79	14.40
MERCURY VAPOR LAMPS								
100	4,000	0.02670	0.03049	45.195	1.20671	1.37800	0.79	3.37
175	7,900	0.02670	0.03049	74.520	1.98968	2.27211	0.79	5.05
250	12,000	0.02670	0.03049	103.845	2.77266	3.16623	0.79	6.73
400	21,000	0.02670	0.03049	163.530	4.36625	4.98603	0.79	10.14
700	41,000	0.02670	0.03049	277.035	7.39683	8.44680	0.79	16.63
1,000	55,000	0.02670	0.03049	391.575	10.45505	11.93912	0.79	23.18
HIGH PRESSURE SODIUM								
50	4,000	0.02670	0.03049	20.010	0.53427	0.61010	0.79	1.93
70	5,800	0.02670	0.03049	28.635	0.76455	0.87308	0.79	2.43
100	9,500	0.02670	0.03049	40.365	1.07775	1.23073	0.79	3.10
150	16,000	0.02670	0.03049	66.585	1.77782	2.03018	0.79	4.60
200	22,000	0.02670	0.03049	84.870	2.26603	2.58769	0.79	5.64
250	27,500	0.02670	0.03049	107.985	2.88320	3.29246	0.79	6.97
310	37,000	0.02670	0.03049	132.135	3.52800	4.02880	0.79	8.35
400	50,000	0.02670	0.03049	167.325	4.46758	5.10174	0.79	10.36
LOW PRESSURE SODIUM								
35	4,800	0.02670	0.03049	21.735	0.58032	0.66270	0.79	2.03
55	8,000	0.02670	0.03049	28.980	0.77377	0.88360	0.79	2.45
90	13,500	0.02670	0.03049	45.195	1.20671	1.37800	0.79	3.37
135	22,500	0.02670	0.03049	62.790	1.67649	1.91447	0.79	4.38
180	33,000	0.02670	0.03049	79.005	2.10943	2.40886	0.79	5.31

SOUTHERN CALIFORNIA EDISON COMPANY

LS-2
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B - MULTIPLE SERVICE/MIDNIGHT 1991

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	0.03415	0.03049	17.943	0.61275	0.54708	0.79	1.95
202	2.500	0.03415	0.03049	35.188	1.20167	1.07288	0.79	3.06
327	4.000	0.03415	0.03049	56.963	1.94529	1.73680	0.79	4.47
448	6.000	0.03415	0.03049	78.042	2.66513	2.37950	0.79	5.83
690	10.000	0.03415	0.03049	120.198	4.10476	3.66484	0.79	8.56
MERCURY VAPOR LAMPS								
100	4.000	0.03415	0.03049	22.820	0.77930	0.69578	0.79	2.27
175	7.900	0.03415	0.03049	37.627	1.28496	1.14725	0.79	3.22
250	12.000	0.03415	0.03049	52.434	1.79062	1.59871	0.79	4.18
400	21.000	0.03415	0.03049	82.571	2.81980	2.51759	0.79	6.13
700	41.000	0.03415	0.03049	139.883	4.77700	4.26503	0.79	9.83
1,000	55.000	0.03415	0.03049	197.717	6.75204	6.02839	0.79	13.57
HIGH PRESSURE SODIUM								
50	4.000	0.03415	0.03049	10.104	0.34505	0.30807	0.79	1.44
70	5.800	0.03415	0.03049	14.459	0.49377	0.44085	0.79	1.72
100	9.500	0.03415	0.03049	20.381	0.69601	0.62142	0.79	2.11
150	16.000	0.03415	0.03049	33.621	1.14816	1.02510	0.79	2.96
200	22.000	0.03415	0.03049	42.853	1.46343	1.30659	0.79	3.56
250	27.500	0.03415	0.03049	54.525	1.86203	1.66247	0.79	4.31
310	37.000	0.03415	0.03049	66.719	2.27845	2.03426	0.79	5.10
400	50.000	0.03415	0.03049	84.487	2.88523	2.57601	0.79	6.25
LOW PRESSURE SODIUM								
35	4.800	0.03415	0.03049	10.975	0.37480	0.33463	0.79	1.50
55	8.000	0.03415	0.03049	14.633	0.49972	0.44616	0.79	1.74
90	13.500	0.03415	0.03049	22.820	0.77930	0.69578	0.79	2.27
135	22.500	0.03415	0.03049	31.704	1.08269	0.96665	0.79	2.84
180	33.000	0.03415	0.03049	39.892	1.36231	1.21631	0.79	3.37

SOUTHERN CALIFORNIA EDISON COMPANY

LS-2
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C - SERIES SERVICE/ALL NIGHT 1991

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	0.02670	0.03049	29.528	0.78840	0.90031	3.55	5.24
202	2,500	0.02670	0.03049	64.567	1.72394	1.96865	3.55	7.24
327	4,000	0.02670	0.03049	97.638	2.60693	2.97698	3.55	9.13
448	6,000	0.02670	0.03049	136.614	3.64759	4.16536	3.55	11.36
690	10,000	0.02670	0.03049	227.559	6.07583	6.93827	3.55	16.56
MERCURY VAPOR LAMPS								
100	4,000	0.02670	0.03049	51.675	1.37972	1.57557	3.55	6.51
175	7,900	0.02670	0.03049	85.574	2.28483	2.60915	3.55	8.44
250	12,000	0.02670	0.03049	117.819	3.14577	3.59230	3.55	10.29
400	21,000	0.02670	0.03049	183.963	4.91181	5.60903	3.55	14.07
700	41,000	0.02670	0.03049	314.184	8.38871	9.57947	3.55	21.52
1,000	55,000	0.02670	0.03049	442.338	11.81042	13.48689	3.55	28.85
HIGH PRESSURE SODIUM								
50	4,000	0.02670	0.03049	30.746	0.82092	0.93745	3.55	5.31
70	5,800	0.02670	0.03049	40.834	1.09027	1.24503	3.55	5.89
100	9,500	0.02670	0.03049	58.128	1.55202	1.77232	3.55	6.87
150	16,000	0.02670	0.03049	83.590	2.23185	2.54866	3.55	8.33
200	22,000	0.02670	0.03049	111.933	2.98861	3.41284	3.55	9.95
LOW PRESSURE SODIUM								
35	4,800	0.02670	0.03049	24.225	0.64681	0.73862	3.55	4.94
55	8,000	0.02670	0.03049	34.200	0.91314	1.04276	3.55	5.51
90	13,500	0.02670	0.03049	61.750	1.64873	1.88276	3.55	7.08
135	22,500	0.02670	0.03049	87.875	2.34626	2.67931	3.55	8.58
180	33,000	0.02670	0.03049	104.025	2.77747	3.17172	3.55	9.50

SOUTHERN CALIFORNIA EDISON COMPANY

LS-2
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D - SERIES SERVICE/MIDNIGHT 1991

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	0.03415	0.03049	14.918	0.50945	0.45485	3.55	4.51
202	2,500	0.03415	0.03049	32.620	1.11397	0.99458	3.55	5.66
327	4,000	0.03415	0.03049	49.327	1.68452	1.50398	3.55	6.74
448	6,000	0.03415	0.03049	69.018	2.35696	2.10436	3.55	8.01
690	10,000	0.03415	0.03049	114.964	3.92602	3.50525	3.55	10.98
MERCURY VAPOR LAMPS								
100	4,000	0.03415	0.03049	26.113	0.89176	0.79619	3.55	5.24
175	7,900	0.03415	0.03049	43.242	1.47671	1.31845	3.55	6.35
250	12,000	0.03415	0.03049	59.537	2.03319	1.81528	3.55	7.40
400	21,000	0.03415	0.03049	92.961	3.17462	2.83438	3.55	9.56
700	41,000	0.03415	0.03049	158.764	5.42179	4.84071	3.55	13.81
1,000	55,000	0.03415	0.03049	223.523	7.63331	6.81522	3.55	18.00
HIGH PRESSURE SODIUM								
50	4,000	0.03415	0.03049	15.539	0.53066	0.47378	3.55	4.55
70	5,800	0.03415	0.03049	20.638	0.70479	0.62925	3.55	4.88
100	9,500	0.03415	0.03049	29.379	1.00329	0.89577	3.55	5.45
150	16,000	0.03415	0.03049	42.247	1.44274	1.28811	3.55	6.28
200	22,000	0.03415	0.03049	56.572	1.93193	1.72488	3.55	7.21
LOW PRESSURE SODIUM								
35	4,800	0.03415	0.03049	12.240	0.41800	0.37320	3.55	4.34
55	8,000	0.03415	0.03049	17.280	0.59011	0.52687	3.55	4.67
90	13,500	0.03415	0.03049	31.200	1.06548	0.95129	3.55	5.57
135	22,500	0.03415	0.03049	44.400	1.51626	1.35376	3.55	6.42
180	33,000	0.03415	0.03049	52.560	1.79492	1.60255	3.55	6.95

SOUTHERN CALIFORNIA EDISON COMPANY

LS-3 1991
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	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH ANNUAL GWH	BASE ENERGY CHG. (1 * 3)	OFFSET ENERGY CHG. (2 * 3)	CUSTOMER CHARGE RATE
	(1)	(2)				
TOTAL ENERGY	0.02670	0.03049	45.335647	1,210,462	1,382,284	
CUSTOMER CHARGE						
MULTIPLE	0.00000	0.00000	0			8.65
SERIES	0.00000	0.00000	0			109.35

SOUTHERN CALIFORNIA EDISON COMPANY

OL-1 1991 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	0.02670	0.03049	74.520	1.98968	2.27211	5.09	9.35
400	21,000	0.02670	0.03049	168.460	4.49788	5.13635	5.50	15.13
HIGH PRESSURE SODIUM								
70	5,800	0.02670	0.03049	28.635	0.76455	0.87308	5.09	6.73
100	9,500	0.02670	0.03049	40.365	1.07775	1.23073	5.09	7.40
200	22,000	0.02670	0.03049	84.870	2.26603	2.58769	5.49	10.34

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)
MERCURY VAPOR LAMPS								
175	7,900	0.03415	0.03049	37.627	1.28496	1.14725	5.09	7.52
400	21,000	0.03415	0.03049	82.571	2.81980	2.51759	5.50	10.84
HIGH PRESSURE SODIUM								
70	5,800	0.03415	0.03049	14.459	0.49377	0.44085	5.09	6.02
100	9,500	0.03415	0.03049	20.381	0.69601	0.62142	5.09	6.41
200	22,000	0.03415	0.03049	42.853	1.46343	1.30659	5.49	8.26

OL-1 POLE CHARGE

STANDARD POLES	2.20

SOUTHERN CALIFORNIA EDISON COMPANY

DWL 1991

	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	0.02670	0.03049	32.341	0.86350	0.98608	6.55	8.40
RATE B	0.02670	0.03049	32.341	0.86350	0.98608	2.15	4.00
RATE C	0.00000	0.00000	0.000	0.00000	0.00000	0.40	0.40

(END OF APPENDIX C)