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Decision 92-01-018 January 10, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of the SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for: (1) Authority to Revise Its Energy Cost Adjustment Billing Factors, Its Major Additions Adjustment Billing Factor, Its Electric Revenue Adjustment Billing Factor, Its Low Income Surcharge, and Its Base Rate Levels Effective January 1, 1992; (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, 1990 Through March 31, 1991.	Application 91-05-050 (Filed May 24, 1991)

(Appearances are listed in Attachment A.)

I N D E X

OPINION

Summary

This decision reduces authorized revenues related to the Energy Cost Adjustment Clause (ECAC) of Southern California Edison Company (Edison) by $53.3 million. The decision is also the vehicle to determine the revenue allocation and rate design for the lower rates from this ECAC and rate adjustments from other proceedings. The total rate increase to be spread by this decision is $138.4 million, from the following proceedings.

Summary of Currently Estimated Rate Changes

(Millions of Dollars)

Proceeding	Reference	Effective Jan. 20, 1992
ECAC	Current Proceeding	(53.3)
General Rate Case	A.90-12-018, D.91-12-076	48.3
Cost of Capital 1/	A.91-05-024	0.0 1/
Palo Verde Unit 3	D.86-10-023	70.8
Cool Water	D.91-10-030	26.3
Post-retirement Benefit	I.90-07-037 (Advice Letter)	46.3
Total		138.4

1/ Cost of capital is included D.91-12-076.

This decision adopts the Incremental Energy Rate (IER) proposed by Edison and Division of Ratepayer Advocates (DRA), modified by the service level credit recommended by the

Cogenerators of Southern California, of 8,908 Btu/kWh, and an adopted cost of gas of $2.83/MMBtu. The Joint Recommendation of Edison and DRA is adopted, with the service level credit modification. Agricultural and pumping rates are increased no more than system average percentage change (SAPC) and streetlighting and large power rates are reduced without being limited by a floor. All other rates are spread on the basis of equal percentage of marginal cost (EPMC). The nonbaseline to baseline ratio is reduced by increasing the baseline rate by 2.5% more than the domestic average increase. A typical domestic bill will increase by about 2.4% or $1.36.

This decision was issued as a Proposed Decision to which the parties submitted comments. Those comments have been considered and changes have been made in response to those comments and a review of the record.

I. Background

Edison in this ECAC proceeding originally requested rates which would result in a revenue increase of $214.4 million on an annual basis for service rendered on and after January 20, 1992. Edison has also requested to consolidate its 1992 ECAC revenue changes with rate changes being adopted in other proceedings, all to be made effective on January 20, 1992. The proposed ECAC revenue decrease is to be reflected in changes to the Energy Cost Adjustment Billing Factors (ECABF), the Electric Revenue Adjustment Billing Factor (ERABF), the Major Additions Adjustment Billing Factor (MAABF), the Low Income Surcharge (LIS), and base rates. Edison and DRA also recommend that the Commission adopt an annual average IER of 8,856 Btu/kWh for qualifying facility (QF) avoided cost pricing.

The original revenue increase was composed of the following components:

	($M[2])
ECABF	140.8
ERABF	104.1
MAABF	(32.6)
LIS	(11.8)
Base Rates	13.9
Total	214.4

Edison also requested that the Commission find that:

- o Edison's fuel and energy-related costs recorded in the ECAC balancing account from April 1, 1990 through March 31, 1991 were reasonable;

- o The incentive amounts, calculated pursuant to the Nuclear Unit Incentive Procedure, are reasonable;

- o Edison's execution and administration of purchased power agreements with QFs during the record period and the associated power expenses recorded in the ECAC balancing account for the period from April 1, 1990 through March 31, 1991 are reasonable; and

- o The ECAC change should be consolidated with other pending rate changes and made effective January 20, 1992.

At a prehearing conference the forecast phase of the proceeding was separated from the reasonableness issues and set for hearing. DRA's motion to incorporate marginal cost data from Edison's Test Year 1992 GRC was granted.

On August 9, Edison reduced its revenue request to a $31.3 million annual increase and forecast an IER of 8,847 Btu/kWh.

On August 28, DRA recommended that Edison's revenue be reduced $21 million annually and that an IER of 8,862 Btu/kWh be adopted.

On August 30 the Cogenerators of Southern California (CSC) recommended a decrease in ECABF revenue of $204.7 million using Edison's gas price assumptions and $285.2 million using DRA's gas price assumptions. CSC's IER recommendation was 9,567 Btu/kWh using Edison's gas price assumptions and 9,664 Btu/kWh using DRA's gas price assumptions. Edison, DRA, and CSC were the only parties to submit an integrated assessment of forecast revenue requirement and IER.

Industrial Users (IU), California Large Energy Consumers Association (CLECA), Toward Utility Rate Normalization (TURN), the Federal Executive Agencies (FEA), and the California City-County Street Light Association (Cal-SLA) all served testimony on or about August 28, 1991 primarily addressing revenue allocation and rate design issues. None of these parties contested the overall revenue change.

Hearing was held before Administrative Law Judge Robert Barnett. During the course of the hearing, Edison and DRA executed a Joint Recommendation (Attachment B) proposing an annualized revenue decrease of $11.6 million, an annual average IER of 8,856 Btu/kWh, and the settlement or deferral of various other issues. Also during the hearing, CSC submitted supplemental testimony recommending a revenue decrease of $149.5 million and an IER of 9,704 Btu/kWh.

II. Uncontested Issues

A. ERAM, LIRA, MAAC, and Base Revenue Changes

In the Joint Recommendation, Edison and DRA have reached the following agreement on the revenue requirements and present rate revenues associated with the ECABF, ERABF, MAABF, and Low Income Ratepayer Assistance (LIRA) rate components.

Southern California Edison Company

January 20, 1992 ECAC Revenue Change
(Thousand of Dollars)

Item	Revenue Requirement (1)	Present Rate Revenues (2)	Revenue Change (1) - (2) (3)
ECABF	3,210,248	3,287,327	(77,079)
ERABF	176,975	60,222	116,753
MAABF	0	32,591	(32,591)
LIRA	(6,948)	5,841	(12,789)
Base Rates1/	0	5,937	(5,937)
Total ECAC	3,380,275	3,391,918	(11,643)

1/ Reflects increased forecast 1992 base rate revenue attributable to estimated sales during 1992.

The overall revenue change recommended by Edison and DRA in this proceeding is a decrease of $11.6 million. The only rate component contested is the revenue requirement associated with the ECABF.

Edison and DRA have also agreed that the ECABF, ERABF, and LIRA revenue changes should be subject to adjustment to reflect forecast December 31, 1991 balancing account balances based on the most recent recorded information available at the time the Commission issues its decision in this matter. No party opposed these recommendations. Because this decision reflects the most current balancing account balances, the ECAC revenue decrease is $53.3 million rather than $11.6 million.

B. Energy Reliability Index

Edison and DRA both recommended in the Joint Recommendation that the Commission adopt an Energy Reliability Index (ERI) of zero for the forecast period. However, concurrently the Commission reviewed the method used for calculating the ERI in

Investigation (I.) 89-07-004 (Biennial Resource Plan Update (BRPU) proceeding) and determined that ERI should be 0.1 (Decision (D.) 91-11-057). DRA and Edison agree that their recommended ECABF revenue change should be increased to reflect the impact of D.91-11-057 on capacity payments to QFs whose capacity payments are dependent upon an ERI value. Using an ERI of 0.1 Edison's capacity payments to QFs would increase by approximately $1 million.

C. 1992 Turbine Capacity Cost

Edison's proposed annualized combustion turbine capacity cost for 1992 of $79.61 per kW should be adopted by the Commission. No party opposed this recommendation.

D. Fuel Oil Inventory

In the Joint Recommendation, Edison and DRA agreed that for the purpose of setting rates in this proceeding, the recommended ECABF revenue requirement for the 1992 forecast period should reflect the forecast carrying costs associated with 5.0 million barrels of fuel oil inventory. No party opposed this recommendation.

Edison and DRA also agreed in the Joint Recommendation on the ratemaking treatment of losses on sales of fuel oil inventory and that the carrying costs associated with fuel oil inventory in excess of 5.0 million barrels should not be included in the ECABF rate levels to be made effective January 20, 1992.

E. Gas Storage

Edison and DRA recommend that the Commission adopt for the forecast period the gas storage inventory levels contained in the Joint Recommendation. No party opposed this recommendation.

III. The Incremental Energy Rate (IER)

The purpose of an ECAC proceeding is to enable a utility's rates to reflect changes in its fuel and purchased power expenses on an annual basis outside of the GRC cycle. A key component of the calculation is the price paid for power sold to the utility by QFs. In 1978 the federal government enacted the Public Utility Regulatory Policies Act of 1978 (PURPA)[1] which requires electric utilities to interconnect QFs to their grid and purchase all QF energy production. We set the price based on avoided cost pricing.[2] The IER is the proxy for the utility system's efficiency in converting fuel into one kWh of electricity and is used to calculate payments to the variable priced QFs[3] based on the cost of energy avoided by the utility receiving electricity from those QFs. The actual payments to the QFs are calculated by multiplying the posted average gas price by the IER for each kWh of QF energy received by the utility.

The process to determine the IER involves hundreds of assumptions defining the resource mix and method of system operation to meet system load and reliability needs. These include forecasts of sales and load shapes, purchased power availability, fuel and purchased power prices, generating unit heat rates, outages, and many more. These assumptions are then input into a production cost model (ELFIN in this case) and the results from running the model are used for forecasting the resource mix, the IER, and an ECAC revenue requirement. The IER is calculated from the difference between the model simulation with a resource mix

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1 16 USCA 2601 et seq.; 16 USCA 824a.3; 18 CFR § 292.101 et seq. and especially § 292.304; see, Public Utilities Code § 2801 et seq.

2 Avoided cost pricing is mandated by the Federal Energy Regulatory Commission (FERC). (American Paper Inst. v American Elec. Power (1983) 461 US 402, 76 L.Ed. 2d 22.) FERC may grant a waiver of the avoided cost rule and QFs may negotiate individual contracts based on other pricing concepts.

3 Variable priced QFs are those whose payments are based on the IER and fuel prices. These QFs produce approximately 30% of total QF production. The balance of QF production is purchased by the utility through firm contracts entered into with other QFs.

including variable priced QFs (QFs-in) and a model simulation with the variable priced QFs removed from it (QFs-out). In essence this measures the changing marginal/avoided costs of the system due to the presence of the variable priced QFs.

To calculate an IER and the ECAC revenue requirement on a forecasted basis requires the use of production cost models able to simulate the expected results of operating the utility system. While a number of models have been used, ELFIN has been required to be a benchmark model. It was the model used by all parties to this proceeding. As described above, the IER is calculated by performing two production cost model runs which simulate the operation of the utility's generating system. The first run, which is also used to forecast the resource mix and revenue requirement, includes all variable priced QFs in the resource mix. The second run is performed with all the variable priced QFs removed. The change between the production costs of those runs is then divided by the amount of energy delivered by the variable priced QFs to develop a cost per kWh avoided by the utility. This avoided cost rate is then divided by the cost of fuel used by the utility's oil and gas-fired generation units to develop an IER expressed in Btu/kWh. The resulting IER is then used as a basis for developing prices to variable priced QFs for energy sold to Edison, as well as for forecasting Edison's QF expenses in this ECAC.

Because the ECAC revenue requirement is substantially subject to balancing account treatment, an error in the revenue requirement forecast is subject to adjustment. There is, however, an incentive for Edison to forecast as accurately as possible to avoid swings in rates due to under- or overcollections in balancing accounts. For QFs, however, the need to forecast accurately is even more imperative. An improperly high IER will translate into excessive payments to QFs and higher costs to ratepayers, costs that are not subject to any reasonableness review. An improperly low IER will adversely affect QFs.

In D.88-11-052 (29 CPUC 2d 566 at 596-597), we made the following comments regarding the calculation of the IER:

> "The incremental energy rate is a somewhat artificial concept. It first arose in the negotiating conference that developed the interim Standard Offer Number 4 as a way of relating forecasted fossil fuel prices to the utility system's marginal energy costs. A utility's marginal cost of generating energy (expressed in cents per kWh) is a combination of the price it pays for fuel (stated in \$/MMBtu) and the system's efficiency in converting that fuel into kilowatt-hours. The IER, as a measure of the system's incremental efficiency in making this conversion, is therefore expressed in Btu/kWh."
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> "The IER is often and understandably confused with the incremental heat rate, or IHR. The IHR is typically used to express the incremental efficiency of an individual generating unit, and measures the unit's efficiency in producing one more kWh. A unit's IHR will vary with changes in the generation it produces, and most generating units are designed to operate most efficiently within a certain range. References to a system's IHR usually refer to the IHR of the last unit dispatched to meet load. The IHR is also expressed in Btu/kWh."

To properly understand the IER and the interest of the parties who litigated the IER issues one must understand the IER formula and its implications. We have described it above, but it is clearest when set forth algebraically:

$$\frac{(\text{QF-out \$/kWh}) - (\text{QF-in \$/kWh})}{\text{Gas Price \$/Btu}} = \text{IER}$$

The first conclusion to be drawn from the formula is that the IER, which is the basis for determining the payment made by the utility to the QF for electricity, has no relationship to the QFs' costs to produce a kilowatt of electricity. QF costs are irrelevant. Second, in the QF-out computation, if any of the costs of production are increased (such as economy energy, as the QFs contend is proper) the IER rises. Third, in the QF-in computation, if any of the costs of production are decreased (such as dispatching units, as the QFs contend is proper) the IER rises. Many of the operations forecast in ELFIN affect the IER. In this proceeding all changes sought by the QFs would increase the IER. Once the IER is forecast for the test year it does not change, and all variable priced QF payments are based on that IER. The QFs benefit from a high IER and have revenue reduced by a low IER. The utility, however, is indifferent because its IER payment, whether high or low, is part of its costs recovered from the ratepayers in a balancing account. The fundamental theory underpinning payments to QFs, including those dependent on IERs, is to peg that compensation to the costs the utility avoids incurring by not producing those kWh itself. When the costs of the utility in producing energy, including its costs at the margin, are reduced, the payments to variable priced QFs are also reduced. CSC estimates that the difference between its IER recommendation and the Edison/DRA Joint Recommendation is $16 million. CSC would increase payments by $5 million from the present IER and Edison/DRA would decrease payments by $11 million from the present IER.

The controversy in this proceeding is almost entirely concerned with the factors that comprise the utility's costs in determining the IER. We estimate that 80% of the time to prepare for this hearing and 80% of the time in hearing was consumed by the IER issue. If QFs were paid for electricity at a market price, no time would be taken on the issue and the public would know the price was reasonable. We recognize, however, that at present the market for QF power is limited primarily to public utilities. In D.88-11-052 we said "the incremental energy rate is a somewhat artificial concept." After three more years of experience with the concept, we can safely strike the word "somewhat" and substitute "totally."

A. <u>Gas Price</u>

Gas has been and will continue to be the marginal fuel for Edison's own electric generation and the fuel for a significant number of QFs. It is also a major index against which other fuel and energy prices are measured. For most of the parties that have provided testimony in the revenue allocation area, their primary, if not sole, concern was with the manner in which gas prices were to be computed because the level of the various gas price components, when used in conjunction with marginal cost data already established, will have a significant effect on the actual revenue levels attributed to each customer class.

In the area of IER development and determination of the ECAC revenue requirement, the significance of the price of gas is perhaps even greater. It is a component of the overall revenue requirement in the most basic sense because that revenue requirement reflects Edison's overall forecasted fuel bill, among other things. However, its effect on the broader questions involved in modeling the forecasted operation of the Edison system is as critical. The price of gas affects Edison's economic dispatch priority. To the extent it reflects Edison's marginal fuel, it affects what Edison pays for purchased power. It is also a significant cost component in developing Edison's QF expenses.

DRA's and Edison's Joint Recommendation on gas price components is:

	$/MMBtu
California/Arizona Border Price	1.89
Variable Intrastate Price	0.30
Subtotal	2.19
Other Intrastate Costs	0.70
Total SoCal Cost	2.89
Other deliveries	2.60
Deliveries from all Suppliers	2.83

The witness for IU, supported by CLECA, recommended that the marginal cost of gas should be $2.29, consisting of a border price of $1.99 and an intrastate transportation price of $.30. He acknowledged that he did not include all of the intrastate costs Edison would pay to Southern California Gas Company (SoCal) under their service contract (such as demand charges) and explained that the utility's objective in the context of the new transportation options should be to achieve the least costly transportation in reference to its marginal or swing supplies of gas. Reflecting that premise, he recommended a gas cost of $2.29 which assumes Edison can arrange intrastate transportation for its marginal gas supplies under the lower commodity rate assigned to Service Levels 4 and 5 under the Edison-SoCal transportation agreement.

We agree that a utility should attempt to achieve the least costly transportation, but to forecast it we cannot omit to consider costs which the utility will incur. We cannot eliminate the demand and other transportation costs, as IU did. IU's argument was considered and rejected in previous Commission proceedings, the last one being Edison's ECAC D.90-01-048 at p. 17 where we found IU's argument "to be unpersuasive." We remain unpersuaded. We will adopt $2.83 as the cost of gas to be used for all purposes in this proceeding.

B. Service Level 3/4/5 Credit

In accordance with the new rules for gas procurement which went into effect on August 1, 1991 Edison received its service level allocation from SoCal which permits Edison to buy 73% of its gas in Service Level 2/3 (which exceeds the nominal ceiling of 65% in the procurement decision, D.90-09-089 et al.), and the remainder in Service Level 4/5. Because of the higher level of service (i.e., reliability of delivery) of Service Level 2/3, Edison will pay a premium of $0.12 per MMBtu; Edison will receive a credit for its purchases in Service Level 4/5.

In the DRA/Edison Joint Recommendation the rate for Service Level 2/3 reflects a net effect of $0.09 per MMBtu, which is the $0.12 Service Level 2/3 surcharge less a forecast of $0.07 credit for Service Level 4/5. In its testimony, CSC has argued that this credit should be $0.148, given its representations of the actual volume allocations. In D.91-12-075, the Southern California Gas Company Biennial Cost Allocation Proceeding, the Commission adopted a service level credit of $0.17 per MMBtu. We take official notice of that decision. As CSC's forecast is closer to that which we so recently adopted, we will adopt CSC's $0.148 forecast for the service level credit.

C. Cool Water Intrastate Gas Transportation Costs

CSC believes that Edison/DRA have incorrectly forecast intrastate gas transportation costs associated with Pacific Gas and Electric Company's (PG&E) service to Edison's Cool Water generating units using the average cost of gas transportation provided by SoCal. CSC claims that this forecast is inconsistent with the Commission-approved pricing structure for Cool Water transportation service adopted in D.91-05-029, PG&E's most recent cost allocation proceeding. CSC has corrected this error by reflecting the Commission-approved pricing structure for these volumes, which results in a $4.7 million revenue reduction.

Edison succinctly replies that the gas price contained in the Joint Recommendation was the result of compromise knowing that various components of the gas price could go up or down given the market uncertainty that exists today. We agree with Edison. The average price of gas contained in the Joint Recommendation is reasonable and should be adopted without the modifications for Cool Water gas transportation costs suggested by CSC.

D. <u>Forecast of QF Production</u>

A major consideration in determining the resource operations necessary to meet forecast period demand and the major determinant of revenue requirement differences between DRA/Edison and CSC is the forecasted production of QFs. Pursuant to PURPA and various implementing decisions of this Commission, utilities such as Edison are obligated to purchase all of the qualifying production of QFs. The more QF production that exists in the forecast period, the less Edison will be called upon to produce from its own generation system or acquire from other sources. DRA and Edison recommend adoption of a forecast period QF total energy production of 27,760 gigawatt hours (gWh). CSC recommends 25,670 gWh. The impact of differences on this issue alone on the IER is 140 Btu/kWh.

To develop this recommendation an extensive review was undertaken of historical production by QFs. Data was supplied by Edison which provided historical production of each individual QF, grouped by technology type, e.g., cogeneration, geothermal, wind, solar. Edison conducted a survey of each QF which sought a wide range of information, of which a portion was directed to the QF's anticipated production in 1992 and an explanation of any particular factors that influenced that forecast or shed light on anomalies in recorded information. This survey is the product of a Commission directive for DRA and Edison to consult on a survey approach for forecasted QF information. (D.88-09-031, 29 CPUC 2d 314 at 336-337.) DRA was provided a copy of each survey form returned.

In addition to historical trend data, DRA and Edison both used the figures in the survey responses as the most reasonable expectation for 1992 production. An examination of the historical information shows that both the technology and individual QFs are maturing in their experience. Thus, DRA/Edison contend it is not unusual to see upward trends, perhaps with some departures, indicative of that experience. This is in contrast to matured technologies where capacity or availability factors remain reasonably constant from year to year. The data indicates that in recent years recorded production has consistently been exceeding forecasted.

Only CSC filed testimony in disagreement with the DRA/Edison recommendation. The California Cogeneration Council (CCC) supports CSC and makes essentially the same arguments. CSC asserts that in forecasting the amount of purchases Edison will make from QFs during the forecast period, the capacity factors for the various QF technologies should be based on the average of the most recent five years of recorded data. In its opinion the five-year rolling average of recorded data provides the most reliable estimate of the capacity factors for the various QF technologies in the forecast period. This method of determining QF technology capacity factors will provide a more reasonable forecast of Edison's 1992 PURPA purchases.

CSC contends that the Edison/DRA estimates of QF capacity factors by technology are based almost exclusively on inaccurate, inconsistent, and erroneous responses to QF surveys. Edison/DRA's assertion that QF technologies in general exhibit a trend toward higher capacity factors is not supported by the historical operating data for these facilities. Furthermore, the responses to the QF surveys and the Edison-sponsored site evaluations of selected responding QFs show that the survey responses cannot be relied upon in estimating the likely performance of the QF technologies. Therefore, in CSC's opinion, the Commission should reject Edison/DRA's flawed estimates of QF capacity factors.

CSC argues that a number of factors can cause swings in the capacity factor for any of the QF subcategories. These factors include: (1) the timing of plants coming on-line at various points during a given month; (2) weather variations affecting solar, wind, and hydro facilities; (3) forced outages; (4) technological improvements; and (5) operator experience. Of these factors, weather conditions, forced outages, and problems determining on-line dates are difficult, if not impossible, to predict. It claims that using an average of historical data compensates for these unpredictable occurrences. For this reason, historical operation based on several years of performance is frequently used to project future availability. CSC points out that DRA used historical data to predict QF capacity factors in Edison's last ECAC proceeding. This recognized practice of using the five-year average of recorded data is also consistent with Edison's method of estimating the performance of its own generating units and in projecting future availability of economy energy.

We will adopt the DRA/Edison forecast. We agree that QF electric production is a maturing technology which over the last five years has shown increases in output caused by improved equipment and more experienced operators. In this instance a trend which reflects this maturation process is a more reliable indicator than a historical average which would predict a forecast lower than recent recorded experience. There are many instances when using averages is the proper method of forecasting. Certainly when data appear to be relatively consistent from year to year moving within certain expected limits, when considering a mature plant, or when the cycles are obvious, using a historical average would be appropriate. But when the numbers show a trend, as in this case, a trend should be used.

CSC complains that the Edison/DRA approach to estimating 1992 capacity factors for the various QF technologies places great weight on responses to Edison's QF surveys. It says the estimated 1992 capacity factors for the eight petroleum-related QF subcategories are taken directly, without modification, from the survey responses provided by the eight petroleum-related QF projects. These eight projects alone provide approximately 38% of the projected QF energy production in the Edison/DRA proposal.

We do not understand CSC's complaint. We see nothing wrong with asking a QF to predict its production for a forecast year. Who better would know? And when that forecast confirms independent data, we have more, rather than less, confidence in the forecast. DRA convincingly points out that these eight QFs whose forecasts CSC so vociferously denigrates are all CSC clients.

E. Economy Energy Pricing

Economy energy plays an important role in the Edison forecasted resource mix. For the forecast period, Edison and DRA are jointly recommending a forecasted amount of economy energy of approximately 4,663 gWh. This amount constitutes about 5.7% of the total forecasted resource mix. No party has voiced a difference of opinion regarding economy energy availability. The dispute between Edison, DRA, and CSC relates to the method used to model economy energy in order to calculate economy energy prices.

1. Position of Edison and DRA

Edison and DRA in the Joint Recommendation calculate economy energy prices based on multiplying gas dispatch costs, monthly incremental heat rates, and historical price ratios to determine a monthly energy price. They are in agreement as to the components and methodology used to calculate economy energy prices. The components include agreement on:

a. Gas dispatch prices.

b. 1989-1990 historical incremental heat rates.

c. Five-year (1986-1990) historical weighted average price ratios. These price ratios reflect a relationship between Edison's conventional gas/oil costs compared to the prices paid for economy energy during this five-year period.

d. Calculated seller's cost based on SERAM II input data set escalation rates. This bounded the calculated economy energy price on the lower end to the seller's cost.

e. Economy energy prices which are the same in the QFs-in and QFs-out cases.

Edison's witness testified that because of lower forecasted gas prices, a floor mechanism is needed to ensure that monthly economy energy prices in the model do not fall below the seller's incremental cost. Therefore, the escalated cost of the suppliers was established based on a SERAM II input data set which forecast the expected cost of coal-based energy during 1992. Edison's and DRA's price ratios compare economy energy prices to the cost of conventional gas and oil generation for the period 1986 to 1990. These price ratios are appropriate because they reflect the Edison system resource mix as it occurred, which includes all economy energy purchases.

Edison says the intent of the price ratios is to correlate by time period the cost of economy energy to Edison's conventional gas/oil-fired units' decremental cost of generation. Edison claims that CSC's modification of Edison's price ratios by taking price ratios that are correlated to Edison's gas/oil costs and multiplying them by the coal escalation rates derived from the SERAM II input data base mixes apples and oranges. This changes the historical price ratios and provides no logical basis for forecasting economy energy prices. CSC's approach does not properly replicate the operation of the Edison system in ELFIN. Most importantly, Edison states that CSC has inappropriately modeled economy energy prices differently in the QFs-out run as compared to the QFs-in run when, in fact, there is no justification to do so. This has the effect of unreasonably increasing the IER.

CSC made a number of fundamental errors in its forecast of economy energy prices, in Edison's opinion. CSC agreed that the marginal costs utilized in the development of the historical price ratios reflected a resource mix which included economy energy. However, CSC inappropriately removed all economy energy from the resource mix in determining the ELFIN Edison marginal cost to price economy energy. This assumption is inconsistent with the data upon which the price ratios were developed which included economy energy in the resource mix. To imply that economy energy prices should be based on Edison marginal costs absent economy energy purchases is absurd, according to Edison.

In addition, CSC utilized the total thermal marginal cost from ELFIN to determine economy energy prices rather than using only the conventional gas/oil resources. This method is inconsistent with the development of the economy energy price ratios which are based solely on conventional gas/oil resources. This increases the cost differential between the QFs-in and QFs-out case because coal resources are on the margin in the QFs-in case but are not in the QFs-out case, and coal resources are less expensive than gas/oil resources.

Edison believes CSC's economy energy prices in the QFs-in case are below the supplier's cost of generation about 40% of the time when compared to Edison's evaluation of supplier's cost. CSC argues that supplier's costs have been taken into account based on escalating the historical price ratios. However, because CSC has not replicated system operation in ELFIN to determine marginal costs, Edison claims these prices are artificially low due to utilizing total thermal marginal costs derived from CSC's ELFIN simulation, thereby lowering the costs in the QF-in run. DRA and Edison instead used floor prices to relate economy energy prices on the lower end to the supplier's cost of generation.

Edison is very concerned about the significant difference between the modeling used in the Joint Recommendation and CSC's modeling in regard to the issue of economy energy prices in the QFs-out run as compared to the QFs-in run. The Joint Recommendation models economy energy as having the same price in both runs, whereas CSC has modeled economy energy as being more costly in the QFs-out run than in the QFs-in run. In the case of economy energy, CSC hypothesizes that, were variable-priced QFs not to exist, the economy energy prices that Edison would pay would be higher. In Edison's view, however, by increasing the price of all economy energy in the QFs-out run, CSC seeks to incorporate "indirect feedback effects" from the national economy as a whole back into the calculation of the IER. An "indirect feedback effect" is a situation in which a change in QF production impacts another market which in turn affects Edison's costs. The direct effect of CSC's higher economy energy prices in the QFs-out run is to increase the IER.

Edison says there are practical reasons why indirect feedback effects should not be incorporated into the calculation of the IER. First, the estimation of the magnitude of these effects is inherently imprecise and subjective and can be greatly overstated, as CSC has done in the case of economy energy. Second, there are potentially many markets that may affect the costs of the utility through an indirect mechanism. It would be burdensome to exhaustively identify each market and then quantify for each market the indirect impact on the utility's cost if QFs did not exist.

Edison gives other examples, besides economy energy, of indirect feedback effects. Any commodity that is purchased by the utility whose price could change if QFs did not exist is an example of an indirect feedback effect. One example proffered by Edison is equipment supply. If the price of equipment that Edison purchases in order to produce electricity is different than it would be if QFs did not exist, then the equipment supply market would show an indirect feedback effect. If indirect feedback effects should be considered in the IER calculation, then all such examples, not just the economy energy and equipment supply examples, should be quantified and included in the IER calculation. Adoption of the principle of considering indirect feedback effects in the IER calculation is not practical and cannot be accurately modeled using ELFIN.

Edison contends that the principle of incorporating indirect feedback effects into the calculation of the IER should be rejected by the Commission on conceptual grounds as well. Such a policy, if adopted and if applied to economy energy or other markets, will result in an inefficient allocation of resource production between QFs and the utility, and eventually in higher rates charged to ratepayers. This is because incorporating indirect feedback effects results in the price paid to QFs exceeding the marginal cost of the utility.

DRA distinguishes D.88-11-052 (29 CPUC 2d 566 at 601-602) in regard to the use of seed runs. First, as far as DRA is aware, this Commission has never previously been presented with the same seed run methodology that CSC proposes in this case. Second, the seed runs which CSC contends the Commission adopted in D.88-11-052 had characteristics which differ from CSC's proposed seed runs: They did not remove economy energy from the runs, and they applied only to PG&E.

DRA says that in terms of economy energy purchases, PG&E is very different from Edison. PG&E is effectively confined to a single market for economy energy, the Pacific Northwest. Edison actively participates in both Pacific Northwest and Pacific Southwest markets, plus the California market. (See, e.g., D.91-05-028 at 56, et seq.) The contention of CSC is that the seed run is necessary to "reflect the impact that the removal of QFs from Edison's system would have on the price of economy energy." However, the CSC approach goes beyond that. CSC removes all economy energy and then does a QF-in and QF-out run. This requires the Edison system to operate in such a manner to replace nearly 17% of its total resource energy requirements. The assumption inherent in this method is that this total replacement of QFs and economy energy will be by the additional use of Edison's existing thermal resources. This, in DRA's opinion, is nonsense.

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

CSC does not dispute Edison/DRA's forecast of the amount of economy energy available to Edison during the forecast period. However, it vigorously disputes the proper method for determining economy energy prices for the forecast period. It contends this issue is significant not only because it affects the revenue requirement and IER during the forecast period, but also because CSC is calling upon the Commission to reaffirm prior precedent directing modelers to use the seed run methodology in forecasting economy energy prices.

CSC believes there are two fundamental flaws with the manner in which Edison/DRA have forecast the price of economy energy in both the QF-in and QF-out runs of the ELFIN model. First, while the parties agree that economy energy prices bear a direct relationship to both Edison's decremental costs and the selling utilities' cost of generation, CSC asserts that Edison/DRA base their estimates of Edison's system decremental costs and the selling utilities' generation costs on outdated cost information, instead of escalating these costs to reflect the forecast period. Second, CSC asserts the Edison/DRA pricing methodology fails to capture the expected reactions of the selling utilities to variations in Edison's system costs caused by changes in Edison's resource mix.

CSC argues that the Edison/DRA economy energy pricing methodology should be rejected because Edison/DRA derive their pricing ratios based on outdated historical incremental generating cost information for both the selling utilities and Edison, rather than employing 1992 generation cost forecasts. The Edison/DRA failure to escalate the historical data supporting the seller's generation costs and Edison's system decremental costs forced Edison/DRA to adopt a floor price mechanism because the ELFIN model was predicting economy energy prices which were simply too low. CSC maintains that Edison's use of an average of historical cost information from 1986 through 1990, instead of forecast 1992 costs, resulted in economy energy price predictions which in some instances are on the floor 6 out of 12 months for on-peak transactions and 8 out of 12 months for off-peak transactions.

CSC corrected these alleged failures by (1) determining price ratios between economy energy prices and Edison's system decremental cost using a forecast of Edison's 1992 system generation costs derived from the ELFIN model; and (2) determining the selling utilities' 1992 generation costs for economy energy using escalation factors contained in the SERAM II data files. In CSC's opinion, this economy energy pricing methodology ensures that the historical relationship between economy energy prices, Edison's decremental costs, and the selling utilities' costs of generation are all based on properly escalated 1992 forecast generation costs. This method provides a system for estimating economy energy prices in the forecast period based on the historical relationship between these three factors without having to rely on subjective floor prices.

CSC declares that the seed run methodology allows the ELFIN model to predict the Edison marginal cost that is applied to the updated price ratios used to determine the price of economy energy in the forecast period. The product of the seed run marginal cost and the pricing ratios is the price for economy transactions in 1992. Furthermore, the seed run is also performed in the QF-out run in order to reflect the reaction of selling utilities to the effect that the removal of significant amounts of variably priced QF energy would have on Edison's system decremental costs. This method causes the price of economy energy to be higher in the QF-out run than in the QF-in run.

CSC argues that Commission precedent supports the use of the seed run methodology for forecasting economy energy prices. In D.88-11-052, the Commission adopted the seed run methodology for forecasting economy energy prices for PG&E. (D.88-11-052, at 38.) In that decision, the Commission stated:

> "The seed run chooses between Northwest [economy] power purchases and incremental conventional generation on an economic basis. <u>The seed run thus provides more refined approximations of the incremental fossil generation costs.</u>" <u>Id.</u> (Emphasis added.)

Furthermore, CSC points out that the Commission recognized that seed runs should be performed in both the QF-in and QF-out runs. <u>Id.</u> at 65. Rejecting PG&E's attempt to hardwire fixed economy energy prices in the QF-out run, the Commission concluded that "the price of Northwest [economy] power should be permitted to vary in the QFs-out run." <u>Id.</u> at 66. The Commission explained that:

> "A separate seed run for the QF-out case will simulate the expected reaction of Northwest [economy] sellers to the hypothetical loss of variably priced power from QFs and PG&E's consequent greater reliance on thermal generation. <u>Thus, modelers should do a separate seed run to determine the price of Northwest [economy] power in the QFs-out case for 1989.</u>" <u>Id.</u> (Emphasis added.)

CSC contends that these same modeling principles are applicable to the forecast of economy energy prices for Edison during the ECAC period. Edison/DRA allow economy energy prices to vary in the QF-in run based upon historical relationships between economy energy prices and Edison's 1989-1990 system decremental cost, but hold economy energy prices constant in the QF-out run. CSC says the Commission has found that, contrary to Edison/DRA's assertions, sellers of economy energy would react to the removal of variably priced QF power from a utility's system by raising their prices in relation to the increased system decremental costs of the purchasing utility and that such changes should be reflected in IER modeling. (D.88-11-052 at 66.) CSC urges the Commission to reaffirm the use of the seed run methodology in this proceeding. It claims there is absolutely no reason that the economic principles underlying the adoption of this modeling principle in D.88-11-052 should not be applied to this proceeding.

3. <u>Discussion</u>

The Joint Recommendation process for determining economy energy prices is reasonable and will be adopted. The prices were based on historical ratios and accounted for the forecast drop in gas prices by adopting a floor price mechanism to assure that economy energy prices in the ELFIN model would not be forecast at less than the seller's incremental cost. By using a 1992 coal price forecast in computing the price, the Joint Recommendation allowed for seller's increased costs. CSC's escalation of price ratios fundamentally changes the ratios such that there is no correlation to historical relationships and provides no logical basis for forecasting economy energy prices.

In the QFs-in run, CSC's economy energy price mechanism allows the cost of economy energy to seek its own level even though CSC's forecast of these costs is below the suppliers' cost of generation. This result has the effect of minimizing economy energy prices in the QFs-in run, despite the escalated price ratios, thereby increasing the IER.

CSC's procedure which removes all economy energy from the resource mix to forecast the price of economy energy in ELFIN is wrong. That method has no relation to how Edison, or any utility, operates its system. The interconnected marketplace normally has surplus energy to market as a result of utility load and resource diversity. When Edison purchases economy energy the system incremental cost at that time is used as an input in making the purchase decision. Other economy purchases are not removed from the equation to determine Edison's incremental costs or the cost that Edison would be willing to pay. ELFIN should try to replicate the real world to the extent possible; CSC's method does not.

CSC has excluded economy energy availability in the QFs-out run. This unjustifiably increases the ELFIN marginal cost output due to additional gas generation and thus maximizes the price of economy energy in the QFs-out run. Thus, CSC's methodology results in maximizing the differential dollars between the QFs-in and QFs-out runs, thereby increasing the IER.

The same economy energy prices should be used in ELFIN for both the QF-in run and the QF-out run. There should be no escalation of economy energy prices in the QF-out run. CSC's argument to the contrary is not persuasive. CSC asserts that we authorized the escalation in D.88-11-052 (<u>PG&E</u>, 29 CPUC 2d 566, 601). In our opinion D.88-11-052 does not control. First, in <u>PG&E</u> we only considered the treatment of Northwest economy energy; Edison has the ability to purchase economy energy from the Northwest, the Southwest, and to a lesser extent California. With more sellers in the market prices need not escalate. There is no evidence that Edison moves the economy energy market. Second, in <u>PG&E</u> we were extremely reluctant when we chose to assume an increase in price. We said:

> "The <u>issue is even more artificial than the parties have defined it</u>.
>
> * * *
>
> "<u>We are thus forced to choose between two unrealistic alternatives to resolve a hypothetical problem.</u> In keeping with our adopted QFs-in/QFs-out approach to calculating the IER, we conclude that the price of Northwest power should be permitted to vary in

> the QFs-out run." (29 CPUC 2d 566, 601; emphasis added.)

Our reluctance in PG&E is obvious. When describing issues as "artificial" and solutions as "two unrealistic alternatives" it is clear our choice was forced, rather than confident. We now have three years more of experience and a proceeding with substantial evidence that there is a difference between PG&E's 1989 operations and Edison's 1992 operations.

Third, in prior Edison ECAC proceedings the economy energy price was constant in both runs. (e.g., D.88-09-031, 29 CPUC 2d 314, 337-338, 344; D.90-01-048; D.90-12-067.) We see no reason to depart from the IER methodology of prior Edison ECACs. There are sufficient differences between Edison and PG&E to support different results. We cannot affirm CSC's theory that with QFs out economy energy prices would rise, but every other cost would remain constant.

Much more than ELFIN inputs would be affected. The adoption of such a policy would result in the price paid to QFs exceeding the marginal cost of the utility, and therefore promote a larger than economically efficient quantity of QFs to produce energy. The end result would be to promote an economically inefficient allocation of energy production between QFs and the utility, which would imply higher than necessary costs of production, and higher than necessary rates.

F. To "COMMIT" or "NCOMMT"

Edison's system operators "commit," or start-up, enough firm generation resources to meet the anticipated peak load of the day, plus a spinning reserve margin equal to the larger of 7% of the peak load or the largest single contingency on the Edison system. The number of units committed by operators has a significant impact on the total costs of serving the load. More commitment of resources increases production costs as compared to less commitment.

The ELFIN model offers the production cost modeler two options to choose from in determining how many generation units will be committed to serve the load in each month: the "COMMIT" option and the "NCOMMT" option. Each option operates by establishing a commitment target equal to the peak load of the month plus the required spinning reserve margin and then committing enough units to meet that target. The difference between the two options is in how many MW each unit counts for in contributing to the target. The COMMIT option counts each unit at its capacity derated for both maintenance and forced outages. The NCOMMT option counts each unit at its capacity derated for maintenance outages only. Thus, if a modeler uses the NCOMMT option fewer resources are required to achieve a given commitment target than if the COMMIT option is used.

The choice of which option to use, COMMIT or NCOMMT, affects both the IER and revenue requirement. In relation to the IER computation the COMMIT option lowers the IER while the NCOMMT raises the IER. Edison and DRA recommend COMMIT; CSC recommends NCOMMT. The basis for making the choice between COMMIT and NCOMMT should be which option most accurately replicates actual system operations in the probabilistic ELFIN model. The economic effect of using NCOMMT is to reduce baseload costs and increase incremental costs so costs in the QF-out run will increase as higher priced units are substituted for QF energy.

1. Position of Edison and DRA

Edison and DRA argue that in making the assessment of which option most accurately replicates actual system operations, the difference between real time, real world system operations and the probabilistic ELFIN production cost model must be considered. In the real world, when operators make commitment decisions, units are either available or not available, and the operators know which units are available and which are not. In the ELFIN model, units are only available with some probability less than one. In other words, a unit with a 10% forced outage rate is 90% "there" and 10% "not there" in the probabilistic ELFIN model.

This, they contend, is the crucial point in understanding why COMMIT is the correct option to use in the ELFIN model. If the NCOMMT option is used, the commitment target will seemingly be achieved based on the rated, or full, capacity of the generation units. But each unit is "not there" in the ELFIN model with a probability equal to its forced outage rate. Thus, if a target is achieved based on rated capacity, when one considers that each unit is not there some of the time, the commitment target will not be achieved. The COMMIT modeling convention correctly compensates for this phenomenon by derating each unit by its forced outage rate in counting its contribution toward achieving the commitment target. The effect of derating each unit by its forced outage rate is to commit more units to cover for the shortfall in commitment due to units being not there some of the time as the result of forced outages.

Edison gives the following example: In actual system operation a utility may have ten generating units of 100 MW each with a probability that one of those ten units will not start when called upon to meet system requirements. Thus, collectively these units can only be depended upon to provide 900 MW (nine units at full capacity) or 90% of total rated capacity. If the utility needs 1,000 MW, another unit must be committed. ELFIN is incapable of exactly replicating this operation. In production cost modeling, a resource is only available with some probability, thus yielding a capacity factor of less than 100%. In other words, in order to simulate this hypothetical system operation, ELFIN, using the COMMIT variable, recognizes ten units at 90% of each unit's rated capacity for a total of 900 MW. As in actual system operation, ELFIN will now commit an additional unit to meet the 1,000 MW system requirement. If the NCOMMT variable is used, ELFIN will recognize all ten units at 100 MW each, ignoring the probable unavailability of a unit due to a forced outage, and thereby undercommitting resources. NCOMMT simply does not replicate actual system operation where forced outages cannot be ignored.

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

CSC states that the COMMIT variable in the ELFIN model should be rejected because it overstates Edison's need for generating units. CSC recommends the NCOMMT variable. CCC supports CSC.

CSC claims that Edison's own testimony admits that the Edison system for the forecast period will maintain a 26.2% reserve margin. This translates into excess capacity in the amount of 1,700 MW above Edison's 16% target reserve margin. Thus, after removing the 1,100 MW of as-available QF capacity in the QF-out run, Edison is left with 600 MW of excess capacity above its 16% target reserve margin. With this much excess capacity on its system, CSC believes it is unrealistic to suggest that Edison will need to include an additional substitution unit in the QF-out run. This illogical result stems from the Edison/DRA use of the COMMIT variable in committing units to the system. Using this derated capacity results in the overcommitment of resources. This overcommitment of units results in Edison's having to acquire additional capacity in the form of a 320 MW unit - a substitution unit - when approximately 1,100 MW of firm variable price QF capacity is taken off the Edison system in the QF-out run. The use of a substitution unit in the QF-out run would be appropriate if Edison had insufficient resources to meet its needs absent the variable priced QF capacity. However, this is not the case. Edison's loads and resources for the forecast period indicate a surplus of nearly 1,700 MW in excess of the amount required to satisfy the planning and operational reserves which Edison has determined are adequate. Thus, the removal of 1,100 MW of firm variable price QFs would still leave Edison with 600 MW in excess of its needs. Therefore, the operation of a substitution unit in the QFs-out run is illogical and unnecessary.

3. <u>Discussion</u>

Both sides have cited Commission precedent in support of their positions. Edison and DRA cite D.88-09-031, an Edison ECAC proceeding, where this same issue was litigated. In that decision the Commission found that the realities of Edison's system operations include the realities of the probability of forced outages and therefore it is reasonable for ELFIN to reflect this probability and its impact on the availability of Edison's system capacity. CSC cites D.88-11-052, a PG&E ECAC proceeding, where we said that "modelers should correct for ELFIN's derating capacity for forced outages in committing units to meet commitment targets." (29 CPUC 2d 566, 595.) This means to use the NCOMMT variable, the rated unit commitment option. Edison counters that in D.90-03-060 (36 CPUC 2d 2), a recent BRPU decision, we ordered PG&E to use the COMMIT variable.

We have reviewed our prior decisions in this area in light of the evidence in this case regarding the operation of the Edison system and have concluded that the use of the COMMIT variable best replicates actual system operations in the probabilistic ELFIN model. We are impressed with Edison's argument that dispatchers must consider the probability of forced outages and allow for it. As soon as a unit goes down, another must be available to maintain system integrity. COMMIT replicates this;

NCOMMT does not. Although whether a particular unit will incur a forced outage is, by definition, unpredictable, the history of system operations will show a pattern of forced outages which must be considered.

We agree with Edison that CSC is wrong when it equates the 16% planning reserve criteria with the 7% spinning reserve operating criteria in reaching its conclusion that Edison has adequate capacity without adding a substitution unit. There is no relationship between the two criteria. It is not the case that if planning reserves exceed the planning reserve criteria by X% that spinning reserves will be able to exceed the required spinning reserve margin by X%. Finally, we note that the "ELFIN Algorithms Guide" prepared by the Environmental Defense Fund, the sponsor of ELFIN, supports the method of derating capacity for forced outages by use of the COMMIT variable.

G. <u>Automatic Generation Control (AGC)</u>

AGC is a computer-regulated dispatch system which allows the capability of a thermal unit to automatically react to changes in load on the Edison system. AGC generation constitutes "regulation" and is necessary to continuously match system load with an equivalent amount of generation. To operate Edison's control area within control performance criteria, there is a need to maintain an adequate number of units on AGC for downward or upward regulation requirements at all times. Division Order 5 (DO-5) is an operating procedure in which a unit is manually set at minimum operating levels.

The parties dispute whether the need for regulation on Edison's system that occurs in real time operations can be reflected in the ELFIN model. Edison's and DRA's modeling recognizes that there is a system minimum regulation requirement which is reasonably represented in the ELFIN modeling by representing the 480 MW units at their low AGC limit. The production simulation modeling that Edison and DRA have provided reflects the expected actual system operations and expenses during the forecast period. Keeping some Edison units on AGC is required at all times in the real world. While the ELFIN model cannot replicate the actual computer function of matching load to generation, Edison has not asked ELFIN to do that. The AGC capability on the Edison system is reasonably represented in ELFIN by limiting the operation of the four 480 MW units to their AGC operating ranges.

CSC argues that Edison's operators attempt to reduce costs at all times and on all operating levels. Thus, when load is low the most economic operations would call for reducing units to their minimum levels. This can be modeled by permitting all units to operate within the full range of their abilities, including dropping to their DO-5 minimums. Modeling units such that they can operate at their lowest levels when it is economic to do so simulates actual system operations. Therefore, the Commission should direct modelers to permit the ELFIN model to run units within the full range of the DO-5 operating levels.

Edison's use of AGC in its model is correct. AGC provides the regulation necessary to continuously match Edison's system load with an equivalent amount of generation. AGC must be accounted for to reflect the actual operation of Edison's system. CSC's modeling of Edison's thermal units at DO-5 minimums does not replicate Edison's actual operations. We have adopted AGC minimum levels in our recent BRPU proceeding D.90-03-060 and should do so here.

H. Must-Run Units

Edison's system operating requirements dictate that a number of oil and gas units from certain generating stations be on line at all times for system reliability reasons. CSC advocates designating the must-run units after the ELFIN model is first allowed to determine economic dispatch of units without artificial constraints. CSC then reviews the ELFIN output to determine whether additional units must be run to satisfy system operating constraints, which results in fewer must-run unit designations. Thus, in CSC's opinion, the efficient operation of the system is maximized. CSC's modeling of must-run units attempts to meet Edison must-run requirements on an economic priority list basis and does not replicate Edison's system operation.

Edison argues that it does not commit units based solely on an economic priority list to meet system must-run requirements. It says that it satisfies its system reliability requirements by committing those units which have been determined to best meet system needs on the basis of their location, availability, dependability, and a number of other factors besides economics. After satisfying system reliability requirements, Edison commits units based on an optimized unit commitment to minimize total production costs.

In order to replicate actual system operation in ELFIN, Edison and DRA included as must-run units, the units that are typically on line in Edison's system as must-run units. For example, Edison and DRA included El Segundo Unit 4 which is used more often in actual operation as a must-run unit than the unit chosen by CSC. ELFIN is then allowed to dispatch the remaining available resources on an optimized basis.

CSC's method requires that every time there is a change in the forecast and a new production cost run is made, an iteration is required to determine which unit economically satisfies the must-run system requirement. In our opinion, Edison's and DRA's modeling better replicates actual system operation and constitutes a more reasonable and efficient method for the development of the revenue requirement and the IER and should be adopted.

I. <u>The Bonneville Power Administration (BPA) Contract</u>

On July 31, 1991 BPA gave written notice to Edison that the BPA Sales and Exchange Agreement (BPA contract) would convert to a sale for the year 1991-1992. There is no dispute between the parties that, as result of this notice, the BPA contract will be in the sale mode through July 31, 1992 and all parties have modeled the contract this way. The disagreement occurs in how to model this contract for the remainder of the forecast period. Edison and DRA have modeled the BPA contract in the sale mode through December 31, 1992; CSC has modeled the contract as an exchange from August 1, 1992 through December 31, 1992.

In December 1990, BPA issued its 1990 Pacific Northwest Loads and Resources Study in which it assumes the BPA contract is to be in the sale mode through the year 2000 despite showing an energy deficit. The language in the contract itself indicates that the contract is to be in the sale mode unless notice provisions to the contrary are given by BPA.

CSC says that the Edison/BPA contract has operated as a seasonal exchange since 1989, and that BPA was able to convert the contract to a power sale this year only because of unique circumstances in which BPA was forced to buy excess power this year in order to guarantee enough in case of a drought over the next four years. This excess power permitted BPA to sell to Edison under the contract this year. CSC asserts that Edison/DRA have supplied no evidence to support their contention that these special circumstances will continue into the next Edison/BPA contract year (i.e., August 1992 - August 1993). CSC points out that BPA's published loads and resources analysis indicates an expected BPA deficit over the next ten years. Further, plans in the Pacific Northwest to strengthen weak salmon stocks will cause a loss of 112 average MW in hydro projects located in the Northwest. As a consequence, CSC believes these conditions are highly unlikely to foster the type of circumstances which permitted BPA to convert the contract to a sale this year.

BPA, like any other utility, has an incentive to maximize revenue from the sale of power. In the case of the Edison/BPA contract, the conversion to a power sale enables BPA to sell surplus power it has acquired for the coming water year as part of longer term acquisitions. There is no reason why BPA could not similarly acquire additional power to continue the contract in a sale mode into the next delivery year. Converting the contract to a sale through July 1992 has allowed BPA to make more money than by keeping the contract as an exchange. By keeping the contract as a sale beyond August 1992, BPA continues to make money from this contract. Nor are we persuaded that the Northwest plan for salmon stocks will force BPA to convert the contract back to an exchange. BPA has stated in its BPA Journal that "converting the exchanges to sales will increase the average streamflows in the river system in the summer, which will improve conditions for juvenile fish migrations." Thus, it is not obvious that keeping the BPA contract in the sale mode throughout the forecast period will be detrimental to salmon migration.

We will model the contract as a sale for the entire forecast period.

J. <u>Modeling of the Under 40 MW of QF Resources</u>

Edison intentionally categorized 21 QF contracts with under 40 MW of dedicated firm capacity that are outside the Edison service territory with the group of contracts consisting of QFs with over 40 MW of dedicated capacity within Edison's service territory in determining its capacity and energy forecast. These under 40 MW resources are made up of 86% geothermal-based resources with the remainder being biomass-fueled projects. Edison and DRA believe this approach is reasonable because the load shape of these resources is similar to the over 40 MW classification. They claim that their modeling of these resources more closely replicates actual system operation.

CSC believes that Edison's modeling is an error which Edison refuses to admit. In its ELFIN modeling, CSC corrected this error by including these out-of-territory under 40 MW contracts in the under 40 MW category. Furthermore, CSC has modeled these out-of-territory QF contracts to apply 100% of the QF capacity toward unit commitment, as opposed to the 80% capacity applied by Edison to unit commitment for its in-service-territory under 40 MW QF contracts. In this manner, CSC contends that it has correctly matched the QF capacity with the associated load shape for these contracts as opposed to Edison's mismatch between resources and energy deliveries.

Edison asserts that there was no mismatch and no error. It intentionally categorized these contracts that way because their load shape is similar to the over 40 MW classification. Because Edison's modeling of these resources most closely replicates actual system operation we will adopt its position.

K. To Average or Not to Average the IER Calculation

The final step in the process of determining an IER is to calculate it given the total cost outputs from the QFs-in and QFs-out ELFIN production cost runs. Edison and DRA recommend a method based on performing a separate IER calculation for each of the 12 months, and then calculating the annual IER as the simple average of the 12 monthly IER values with a 0.65% start-up adder. CSC, on the other hand, performs its IER calculation in one step on an annual basis. Under CSC's method the resulting IER is higher than the method proposed by Edison and DRA.

Edison and DRA argue that the IER calculation must be performed on a monthly basis and then averaged to determine an annual IER because gas prices vary on a monthly basis. In order to calculate an IER in one step on an annual basis as CSC recommends, an average annual gas price must be determined to plug into the IER formula. They say there is no method by which such an annual average gas price can be calculated that will result in an accurate IER calculation under all circumstances. Given the circumstances that exist for this ECAC forecast period, and that are likely to exist for the foreseeable future, CSC's annual IER calculation method will overstate the correctly calculated IER.

CSC argues that in order to account for the seasonal variations in gas use and gas price which affect Edison's avoided costs, CSC used a weighted average cost of gas for the entire forecast period in determining the annual average IER. This takes the annual, not monthly, change in costs between the QF-in and QF-out runs and divides this by the annual change in QF generation between the QF-in and QF-out runs and by the weighted average cost of gas. This, in CSC's opinion, provides a much closer estimation of Edison's avoided costs on an annual basis because the seasonal fuel use and fuel cost variations are thereby incorporated into the calculation.

Edison, in Exhibit 10, has calculated the IER algebraically using its method and CSC's method. Edison has shown that under CSC's method if there is a correlation in the fraction of incremental production made up from gas-fired resources with the gas price, the IER will be wrong. It would serve no useful purpose to set forth three pages of algebraic calculation. Suffice it to say we have reviewed the calculation and find it to be accurate and the theory reasonable. CSC's method of calculating the average fuel price for the year is flawed and, therefore, its IER calculation is flawed. We will adopt Edison's and DRA's method of calculating the IER.

IV. Revenue Allocation and Rate Design

A. Revenue Allocation

In this proceeding the revenue allocation is interim in nature. That is, it will be used to allocate the cost for rate changes occurring on or about January 20, 1992. Further allocation, including the setting of major goals will occur in Phase II of Edison's GRC, Application (A.) 90-12-018. In this proceeding we have found the ECAC revenue requirement to be a decrease of approximately $53.3 million. However, we are spreading rates which include the revenue requirement from other proceedings for a total increase of $138.4 million. It is to that $138.4 million that this revenue allocation and rate design portion of the decision is directed.

Both Edison and DRA use the capped EPMC basis to allocate the proposed revenue requirement. Both agree that the net deficiency or surplus due to capping and flooring should be allocated on an EPMC basis to all groups that are not capped or floored. The Commission established this procedure in Edison's last GRC and determined that it should be applied in intervening ECAC proceedings. In Edison's two subsequent ECAC decisions, the Commission adopted a capped EPMC allocation which limited changes in revenues to rate groups. In Edison's last ECAC, the Commission adopted a full EPMC allocation. In this ECAC, by agreement of the parties, we are using the marginal costs and customer usage characteristics found reasonable in Edison's current GRC, A.90-12-018.

DRA recommends continuing the use of a capped EPMC approach to revenue allocation in this proceeding, with the net deficiency or surplus due to caps and floors being allocated on an EPMC basis to all groups that are not capped or floored. DRA recommends a cap of 2.5% over SAPC. Only the agricultural and pumping class would be subject to the cap. DRA recommends a floor of no decrease. Large power and streetlighting are affected by this. The floor recommendation is a matter of some controversy in this proceeding and is discussed in more detail below.

Edison recommends capping the allocation to rate groups at 5% above SAPC except that increases to the agricultural and pumping group should be capped at 3.5% above SAPC and increases to the domestic group at 2.5% above SAPC. The proposed caps recognize the recent difficulties experienced by the agricultural customers and the significant increases in revenues allocated to domestic customers since 1987. Edison recommends that decreases in the allocation to rate groups should be floored at 5% below SAPC.

IU recommends that the Commission adopt Edison's proposed caps and floors, including the 3.5% cap for the agricultural and pumping group. CLECA recommends no caps or floors be used except a 5% cap on the increases to the agricultural and pumping group. Cal-SLA recommends a full EPMC allocation without caps or floors.

The issue of a cap on rates for the agricultural and pumping group has been settled by the Legislature in AB 2236, where it was enacted that this Commission, prior to June 1, 1992, shall not increase rates for electrical services for agricultural and pumping customers by an amount more than the system average rate increase. (1992 Cal Stat. 862.) As required by statute, this decision will increase agricultural and pumping rates by SAPC only.

In regard to streetlighting, we agree with Cal-SLA that neither a floor of no decrease in rates nor a floor of 5% below SAPC should be adopted. Under our policy of EPMC, if a customer class is entitled to a decrease it should receive it, absent some compelling reason. There is no compelling reason here. DRA argues that streetlighting rates are likely to rise in June 1992 when they are again considered in Edison's GRC, especially if a decrease is ordered in this ECAC proceeding. Therefore, in the interest of rate stability, rates should not be lowered now only to be increased in June. Cal-SLA replies, simply, it prefers the decrease to which it is entitled, thank you; should rates increase in June it will pay the increase in June. For similar reasons, we see no need to place a floor on the decrease for large power. We wish to emphasize that these decreases will not limit us in future rate cases to implement, or restrict, future increases or decreases, regardless of magnitude.

B. <u>Rate Design</u>

There are relatively few rate design issues in this proceeding. Virtually all rate design issues are handled in Phase II of the GRC. In general, DRA is in agreement with Edison on rate design issues with a few exceptions.

1. <u>Average and On-Peak Rate Limiters</u>

DRA opposes the continuation of the phase-out of the on-peak rate limiter for the TOU-8 class. DRA recommends that this issue be addressed in Phase II of the Edison GRC, A.90-12-018.

Consistent with past Commission decisions, Edison proposed in its last ECAC to phase out average and on-peak rate limiters. DRA agreed with the proposal and no party opposed it. As a result, the Commission increased the average and on-peak rate limiters above what they otherwise would have been. (D.90-12-067, pp. 58-59.) To continue the policy of phasing out the rate limiters annually in the ECAC proceedings, Edison proposes to set the average rate limiter at 5¢/kWh above the average summer rate for the TOU-8 secondary rate group. DRA finds this proposal reasonable. No party opposed this proposal.

Edison also proposes, consistent with D.90-12-067, to increase the on-peak rate limiter by 15% above the revenue change to the applicable TOU-8 rate group. Only DRA opposed this proposal. It argues that because this rate component is only in effect for the summer months and because the GRC Phase II decision is expected prior to the start of the next Edison summer season, there is no reason to decide it at this time. It is best handled in the GRC. Edison points out that in its last ECAC decision, we ordered the phase-out of on-peak limiters. It argues that we should continue the phase-out in this proceeding to be effective from January 20, 1992 until the GRC decision is implemented; in the GRC proceeding, the future need for on-peak rate limiters should be evaluated.

We agree with Edison. The issue is one that is usually decided in an ECAC proceeding and merely because there is another proceeding in which it may be reviewed is no reason to delay a decision. Edison's position is consistent with our prior decision to phase out on-peak limiters.

2. Ratio of Nonbaseline to Baseline Rates

DRA proposes an increase of 3.5% above the domestic average increase for baseline rates. This will result in a 9.34% increase in the baseline rate and a 2.67% increase in the nonbaseline rate from present rates (based on the revenue requirement used in DRA's testimony). This reduces the nonbaseline to baseline rate ratio from 1.39:1 to 1.307:1.

Consistent with Edison's last two ECAC decisions (D.90-01-048, p. 34; D.90-12-067, p. 60), Edison proposes to increase the total baseline rate by 2.5% more than the domestic average increase. This results in a reduction in the nonbaseline to baseline ratio from 1.39:1 to 1.33:1. TURN proposes a more modest closure between the baseline and nonbaseline rates by allocating any revenue increase to the domestic group on an equal cents-per-kWh basis.

Both Edison's and DRA's proposals are consistent with the requirement to reduce the ratio between baseline and nonbaseline rates. Neither DRA nor TURN presents a compelling argument to change the rate of closure adopted in Edison's last two ECAC proceedings. Edison's proposal continues to make progress toward reducing the tier differential, and takes into account the rate increases experienced by domestic customers in recent years. At the same time, Edison's proposal complies with our policy to proceed with baseline reform and "ensures that in the very near future the level of the LIRA discount and the size of the Tier 1/Tier 2 rate differential are essentially commensurate." (I.88-07-009, D.89-09-044, p. 8.)

Findings of Fact

1. An energy reliability index (ERI) of 0.1 is reasonable and should be adopted.

2. The combustion turbine capacity cost for 1992 of $79.61 per kW should be adopted.

3. The recommended ECABF revenue requirement for the 1992 forecast period should reflect the forecast carrying costs associated with 5.0 million barrels of fuel oil inventory. The carrying costs associated with fuel oil inventory in excess of 5.0 million barrels should not be included in the ECABF rate levels to be made effective by this decision.

4. The gas storage inventory level contained in the Joint Recommendation is reasonable and should be adopted.

5. The Joint Recommendation is reasonable and should be adopted, as modified by our finding on the service level credit.

6. An IER of 8,908 Btu/kWh is reasonable and should be adopted.

7. Reasonable time differentiated IERs should be:

Summer:		
	On-Peak	12881
	Mid-Peak	9237
	Off-Peak	7638
Winter:		
	Mid-Peak	11331
	Off-Peak	8427
	Super-Off-Peak	5845

8. For all purposes in this proceeding the adopted cost of gas should be $2.83 per MMBtu.

9. The service level credit for Service Level 4/5 should be 14.8¢ per MMBtu.

10. The forecast of intrastate gas transportation costs associated with PG&E's service to Edison's Cool Water generating units should be computed by using the average cost of gas transportation provided by SoCal.

11. The forecast of sales for the five customer groups presented by Edison is reasonable and should be adopted.

12. DRA's and Edison's method of forecasting QF production is reasonable and should be adopted.

13. Edison's and DRA's recommended forecast amount of economy energy of 4,663 gWh is reasonable and should be adopted.

14. The pricing of economy energy should be the same in both the QFs-out run and the QFs-in run.

15. It is reasonable to utilize floor prices to relate economy energy prices on the lower end to the supplier's cost of generation.

16. The commitment target established by the COMMIT option in the ELFIN model production cost program is reasonable and should be adopted.

17. The COMMIT option replicates actual system operation where forced outages cannot be ignored. The NCOMMT option does not perform this function.

18. To determine the IER calculation, modelers should perform a separate IER calculation for each of the 12 months and then calculate the annual IER as the simple average of the 12 monthly IER values with a 0.65% start-up adder.

19. It is reasonable to model ELFIN for automatic generation control as Edison and DRA recommend. The model should represent the 480 MW units at their low AGC limit.

20. In order to replicate actual system operation in ELFIN the Edison and DRA must-run units recommendation should be adopted.

21. The BPA contract should be modeled as if it were in the sale mode through December 31, 1992.

22. Edison's categorization of 21 QF contracts with under 40 MW of dedicated firm capacity that are outside Edison's service territory with the group of contracts consisting of QFs with over 40 MW of dedicated capacity within Edison's service territory in

determining its capacity and energy forecast is reasonable and should be adopted.

23. The marginal costs and customer usage characteristics found reasonable in Edison's current GRC, A.90-12-018, are reasonable for use in this ECAC application and should be adopted.

24. Agricultural and pumping customer rates shall be increased no more than SAPC.

25. Rates for streetlighting and large power shall be decreased by an amount which should not be limited by any floor on rates.

26. For all other rate classifications rates shall be spread on the basis of EPMC. The system average increase is 2.1%. (See Attachment D, p. 1.)

27. Edison's proposal to phase out average and on-peak rate limiters is reasonable and should be adopted.

28. Edison's proposal to reduce the ratio of nonbaseline to baseline rates by increasing the baseline rate by 2.5% more than the domestic average increase is reasonable and should be adopted.

29. The increases in rates and charges authorized by this decision set forth in Attachments C, D, and E are justified, and are just and reasonable.

30. TURN is eligible for compensation, pursuant to Rule 76.54. It has previously been found to have met its burden of showing financial hardship for 1991 in D.91-05-029; it has raised numerous issues in this proceeding; and it estimates its budget at $23,000.

31. Edison's proposed changes to its Preliminary Statement are reasonable and should be adopted. They are set forth in Attachment F.

__Conclusion of Law__

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

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company (Edison) may file on 3 days' notice to the Commission and to the public tariffs setting forth the adopted rates set forth in Attachments C, D, and E of this decision, and the changes in its Preliminary Statement set forth in Attachment F, to be effective no earlier than January 20, 1992.

2. An average annual incremental energy rate of 8,908 Btu/kWh shall be used to determine the price paid by Edison to qualifying facilities commencing on the effective date of this order.

This order is effective today.

Dated January 10, 1992, at San Francisco, California.

DANIEL Wm. FESSLER
President
JOHN B. OHANIAN
PATRICIA M. ECKERT
NORMAN D. SHUMWAY
Commissioners

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

N. J. SHULMAN, Executive Director

ATTACHMENT A

List of Appearances

Applicant: Stephen E. Pickett, Bruce A. Reed, Janet K. Lohmann, James M. Lehrer, Michael D. Mackness, and Bridget Joyce, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Michael P. Alcantar, Attorney at Law, for Cogenerators of Southern California; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Barbara Barkovich, for Barkovich and Yap; Patrick J. Bittner, Attorney at Law, for California Energy Commission; Messrs. Morrison & Foerster, by Lynn Haug, Jerry Bloom, and Joseph Karp, Attorneys at Law, for California Cogeneration Council; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth and Joseph S. Faber, Attorneys at Law, for California Large Energy Consumers Association; Henwood Energy Services, Inc., by David R. Branchcomb, for Geothermal Resources Association; Thomas R. Brill and E. R. Island, Attorneys at Law, for Southern California Gas Company; Maurice Brubaker, for Drazen-Brubaker & Associates; Messrs. McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for Cities of Oxnard and Irvine; Messrs. Brobeck, Phleger & Harrison, by Gorden E. Davis, Attorney at Law, for California Manufacturers Association; Michel Peter Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization; Norman Furuta, Attorney at Law, for Federal Executive Agencies; Dian M. Grueneich, Attorney at Law, for California Department of General Services; William Marcus, for JBS Energy, Inc.; Melissa Metzler, for Bakarat & Chamberlin; Karen Norene Mills, Attorney at Law, for California Farm Bureau Federation; John D. Quinley, for Cogeneration Service Bureau; Messrs. Pillsbury, Madison & Sutro, by James N. Roethe and Ed Kolto, Attorneys at Law, for Air Products & Chemicals, Inc.; James Ross, for Regulatory and Cogeneration Services, Inc.; Bartle Wells Associates, by Reed V. Schmidt, for California City-County Street Light Association; Messrs. Downey, Brand, Seymour & Rohwer, by Phil Stohr and Ron Liebert, Attorneys at Law, for Industrial Users; Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Mark P. Trinchero, Attorney at Law, for Kern River Cogeneration Company; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates; Harry W. Long, Jr., and Michelle L. Wilson, Attorneys at Law, for Pacific Gas and Electric Company; Sam De Frawi, for the Naval Facilities Engineering Command; Dave Hermanson, for Sithe Energies U.S.A., Inc.; Jan Smutny-Jones, for Independent Energy Producers Association; and Sara Steck Myers, Attorney at Law, for herself.

Division of Ratepayer Advocates: Robert Cagen, Philip Weismehl, Attorneys at Law, and Linda Gustafson.

(END OF ATTACHMENT A)

ATTACHMENT B

JOINT RECOMMENDATION OF SOUTHERN CALIFORNIA
EDISON COMPANY AND THE DIVISION OF RATEPAYER ADVOCATES

Southern California Edison Company ("Edison") and the Division of Ratepayer Advocates ("DRA") jointly recommend that the Commission adopt the recommendations set forth herein regarding the following jointly proposed revenue change and Incremental Energy Rate ("IER") in this proceeding:

Total ECAC Revenue Change[1]	($11.6 million)
Annual Average IER[2]	8856 Btu/kWh

The testimony of Edison and the DRA support independently derived revenue changes and recommended IER's. Edison and the DRA, upon evaluation of each's recommendations, determined that the differences in each other's recommendations were reconcilable. In the interest of regulatory and administrative efficiency, Edison and DRA agreed to jointly recommend, and not contest, the recommendations set forth in this exhibit.

1. <u>Recommended ECABF Revenue Change</u>

Based on the ECABF revenue requirement set forth in Appendix B to this exhibit, Edison and the DRA recommend that the Commission adopt an ECABF revenue decrease in this proceeding of $77.1 million, adjusted to reflect the following provisions:

(a) Edison and the DRA agree that the adopted revenue change should incorporate Edison's forecast December 31, 1991 balance in the ECAC Balancing Account based on the latest available recorded balance;

(b) Edison and the DRA agree that the adopted revenue change should incorporate the gas transportation rates adopted by the Commission in SoCal's BCAP

---

1 The total ECAC revenue change as set forth is composed of changes to the ECABF, ERABF, MAABF, LIS and Base Rates as set forth in Appendix A to this exhibit. These recommended revenue changes are subject to the provisions set forth in this exhibit.

2 The recommended IER could change if it is necessary to rerun the ELFIN model to incorporate certain of the conditions set forth in this joint recommendation.

(Appendices C and D to the Joint Recommendation are omitted.)

adopted by the Commission in SoCal's BCAP Application No. 91-03-039.

(c) Edison and the DRA acknowledge and agree that the resource assumptions underlying the jointly recommended revenue change provide a reasonable basis for, and are offered in support of the adoption and implementation of the recommended revenue change and annual average IER set forth herein. The resource assumptions underlying this joint recommendation are set forth in Appendix C. Edison and the DRA further acknowledge and agree that these underlying assumptions do not reflect the independent positions of either Edison or the DRA and should not be construed to be an abdication of the rights of either Edison or the DRA to advocate different principles, methodologies or assumptions in other proceedings;

(d) In addition to these provisions, Edison and the DRA agree that the recommended ECABF revenue change shall reflect the conditions set forth in paragraphs 2, 3, 4, 5, and 6 of this exhibit.

2. Time Differentiated IERs

Edison and DRA agree that the recommended annual average IER of 8856 Btu/kWh should be time differentiated for the Forecast Period as follows:

	Peak	Mid-Pk	Off-Pk	Super Off-Pk
Summer	12,805	9,183	7,594	N/A
Winter	N/A	11,264	8,377	5,811

3. Energy Reliability Index

Edison and the DRA recommend that the Commission adopt an ERI of zero (0.0) for determining as-available capacity payments to QFs for the Forecast Period. However, the Commission is currently reviewing the method used for calculating the ERI in I. 89-07-004 (BRPU proceeding). If the Commission adopts a methodology which results in an ERI greater than zero (0.0), the ECABF revenue change recommended herein should be increased to reflect the impact of the resulting ERI on capacity payments to QFs whose capacity payments are dependent upon an ERI value.

4. Fuel Oil Inventory

Edison and the DRA agree to the provisions described in this paragraph regarding Edison's management of its fuel oil

Forecast Period solely for the purpose of setting rates for the Forecast Period in this proceeding.

(a) Target Fuel Oil Inventory Level and Fuel Oil Inventory Carrying Costs In Rates

Edison has forecast a July - December 1992 target fuel oil inventory level of 5.2 million barrels. The DRA has forecast a July - December 1992 target fuel oil inventory level of 4.9 million barrels. Edison and the DRA agree that for purposes of setting rates in this proceeding, the recommended ECABF revenue requirement for the 1992 Forecast Period will reflect the forecast carrying costs associated with 5.0 million barrels of fuel oil inventory.

(b) Ratemaking Treatment of Losses on Sales of Fuel Oil Inventory and Fuel Oil Inventory Carrying Costs

In Edison's updated ECAC testimony (Exhibit 7) Edison forecast the sale of 1.5 million barrels of fuel from inventory during the Forecast Period at an estimated loss of $7.6 million. Due to the uncertainty of forecasting fuel oil market events and prices, and the timing and level of potential losses associated with the disposal of fuel oil inventory, Edison and the DRA agree that:

(1) The forecast losses on the sale of fuel oil inventory and the carrying costs associated with fuel oil inventory in excess of 5.0 million barrels, should not be included in the ECABF rate levels to be made effective January 20, 1992;

(2) One hundred percent of the losses on the sale of fuel oil inventory and all fuel oil inventory carrying costs shall continue to be recorded in the ECAC Balancing Account. However, Edison will establish a tracking account to identify those expenses recorded in the ECAC Balancing Account associated with: (i) 1992 losses on the sale of fuel oil inventory; (ii) the 1992 carrying costs associated with fuel oil inventory levels in excess of 5.0 million barrels; and (iii) associated interest; and

(3) Edison will not reflect the expenses identified in the tracking account in its ECABF rate levels until the Commission issues a decision finding such expenses reasonable.

5. Gas Storage

Edison and the DRA agree to the provisions described in this paragraph regarding Edison's management of its gas storage inventory and recommend that they be adopted for the Forecast Period in this proceeding.

(a) Edison has forecast a gas storage banking total inventory amount of 10.4 MMDth and DRA has forecast a storage banking total inventory of 7.1 MMDth;

(b) Edison and the DRA agree for forecast purposes to reflect 10.4 MMDth of gas storage banking for the Forecast Period in this proceeding;

(c) Edison has also forecast a smog season storage inventory of 10.4 MMDth while the DRA has forecast no smog season storage inventory;

(d) Given the importance of protecting air quality in the Los Angeles air basin, the DRA and Edison agree to reflect both the 10.4 MMDth of gas for the gas storage banking and the 10.4 MMDth of gas for the smog season inventory in the forecast for the 1992 Forecast Period.

6. Ratemaking Issues

The DRA, in its Evaluation Report, raised the following ratemaking issues:

(a) Removal of the "roundings" which Edison included in its calculation of its ECAC balance;

(b) Removal of certain variable fuel handling costs from Edison's ECAC account; and

(c) An adjustment to Edison's CPUC Jurisdictional Factor used in the ECAC account to incorporate the use of "historic" line loss factors.

The DRA indicated that these issues would be addressed it its Reasonableness Report. The DRA also raised the following issues in its Evaluation Report:

(d) Recovery of legal fees associated with fuel supplier refunds through the ECAC; and

(e) Modification of Part G.11 of Edison's Preliminary Statement to change the definition of a fuel cycle as it is used to determine a nuclear unit's Incentive Period.

Edison and the DRA agree that these issues, if not resolved by the parties, should be addressed in the reasonableness phase of this proceeding and any attendant adjustments to the ECAC balancing account or modifications to Edison's tariffs should be made in accordance with the Commission decision issued in the reasonableness phase of the proceeding.

7. ERAM, LIRA, MAAC and Base Rate Revenue Changes

Based on the ERABF revenue requirement set forth in Appendix D to this exhibit, Edison and the DRA recommend that the Commission adopt an ERABF revenue increase in this proceeding of $116.8 million. Edison and the DRA agree that the adopted revenue change should incorporate Edison's forecast December 31, 1991 balance in the ERAM Balancing Account based on the latest available recorded balance.

Edison and the DRA recommend that the Commission adopt a LIS revenue decrease in this proceeding of $32.6 million. Edison and the DRA agree that the adopted revenue change should incorporate Edison's forecast December 31, 1991 balance in the LIRA Balancing Account based on the latest available recorded balance.

Edison and the DRA recommend that the Commission adopt a MAABF revenue decrease in this proceeding of $12.8 million.

Edison and the DRA recommend that the Commission adopt a Base Rate revenue decrease in this proceeding of $5.9 million to reflect increased Base Rate revenues forecast during 1992 attributable to estimated sales during 1992.

8. Revenue Allocation

Edison and the DRA agree that the average price of gas, including demand and transportation charges, should be used in the calculation of marginal energy cost revenues as opposed to using a marginal gas price which ignores demand charges or some component of transportation charges. This is consistent with Edison's 1988 GRC and two subsequent ECAC decisions (D. 87-12-066, page 211; D. 90-01-048, Finding of Fact No. 6; and D. 90-12-067, Conclusion of Law No. 17).

9. Scope and Limitations

Edison and the DRA will not contest in this proceeding, either in hearings or in any other manner before this Commission, or in any other forum, the revenue change and the 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. Except as expressly provided for in this exhibit, this joint recommendation shall not be construed to be acceptance by Edison or the DRA of the methodology, resource assumptions, arguments, or positions taken independently by Edison or the DRA in this proceeding.

Except as expressly provided for in this exhibit, none of the principles or the methodologies underlying this joint recommendation shall be deemed by the Commission or any other entity as precedent in any proceeding or in any litigation except in order to implement in this proceeding the recommendations contained herein. Edison and the DRA expressly reserve the right to advocate different principles or methodologies from those underlying this joint recommendation in other proceedings.

Edison and the DRA 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. Edison and the DRA agree to extend their best efforts to assure the adoption of these recommendations by the Commission as the basis for the ECAC revenue change and the IER for the Forecast Period.

10. 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 19th day of September, 1991.

Southern California Edison Company	Division of Ratepayer Advocates
Janet K Lohmann	Philip Scott Weismehl
Janet K. Lohmann	Philip Scott Weismehl

ATTACHMENT B

APPENDIX A

A.91-05-050

SOUTHERN CALIFORNIA EDISON COMPANY
JANUARY 20, 1992 ECAC REVENUE CHANGE

(Thousands of Dollars)

Line No.	Item	Revenue Requirement	Present Rate Revenues	Revenue Change (1) - (2)
		(1)	(2)	(3)
1. 2.	Energy Cost Adjustment Billing Factor (ECABF)	3,210,248	3,287,327	(77,079)
3. 4.	Electric Revenue Adjustment Billing Factor (ERABF)	176,975	60,222	116,753
5. 6.	Major Additions Adjustment Billing Factor (MAABF)	0	32,591	(32,591)
7. 8.	Low Income Ratepayer Assistance (LIRA)	(6,948)	5,841	(12,789)
9.	Base Rates 1/	0	5,937	(5,937)
10.	Total ECAC	3,380,275	3,391,918	(11,643)

1/ Reflects increased forecast 1992 base rate revenue attributable to estimated sales during 1992.

(END OF APPENDIX A)

A.91-05-050

ATTACHMENT B

SCE/DRA APPENDIX B

JOINT RECOMMENDATION

CALCULATION OF THE ENERGY COST ADJUSTMENT

BILLING FACTOR REVENUE REQUIREMENT

FOR THE 1992 FORECAST PERIOD

(Thousands of Dollars)

Line No.	Description	Amount
1.	Oil	4,381
2.	Chevron Option Payments	8,100
3.	Gas	444,440
4.	Coal	127,357
5.	Nuclear	126,235
6.	Purchased Power	2,430,805
7.	Sub-Total	3,141,318
8.	Less: Off-System Revenues	23,444
9.	Sub-Total: Fuel and Purchased Power Costs	3,117,874
10.	Plus: Nuclear Fuel Carrying Costs	14,378
11.	Fuel Oil Carrying Costs	7,320
12.	Coal Carrying Costs	756
13.	Gas Carrying Costs	1,454
14.	Sub-Total: Fuel Inventory Carrying Costs	23,908
15.	Loss on the Sale of Fuel Inventory	0
16.	Total Fuel, Purchased Power, and	
17.	Other Energy Related Expenses	3,141,782
18.	CPUC Jurisdictional Percentage	99.6347%
19.	CPUC Jurisdictional Allocation	3,130,305
20.	Less: AER Expenses 1/	0
21.	Plus: Estimated January 1, 1992 ECAC	
22.	Balancing Account Balance	47,979
23.	Sub-Total: ECABF Expenses	3,178,284
24.	Plus: F.F. And U. Expenses 2/	31,964
25.	Total ECABF Revenue Requirement	3,210,248

1/ Reflects suspension of the AER pursuant to OII 90-08-006.
2/ Based on an F.F. and U. Factor of 0.9957%.

(END OF APPENDIX B)

(END OF ATTACHMENT B)

ATTACHMENT C

SOUTHERN CALIFORNIA EDISON COMPANY
REVENUE REQUIREMENT CONSOLIDATION
FOR RATE DESIGN PURPOSES
EFFECTIVE JANUARY 20, 1992

(Thousands Of Dollars)

Line No.			Present Rate Revenues	Revenue Change	Revenue Requirement
1.	AUTHORIZED LEVEL OF BASE RATE REVENUES (ALBRR)				
2.	Previously Authorized Rates	1/	3,943,484	---	---
3.	TY-1992 GRC, D.91-12-076	2/	0	68,468	4,011,952
4.	Post-Retirement Benefits, A.L. 913-E	3/	0	21,059	21,059
5.	Post-Retirement Benefits, A.L. 917-E-A	3/	0	25,219	25,219
6.	Palo Verde Unit 3 Deferral, D.86-10-023	4/	0	(20,201)	(20,201)
7.	ALBRR: Effective January 1, 1992		3,943,484	94,545	4,038,029
8.	Palo Verde Unit 3 Deferral		0	20,201	20,201
9.	ALBRR: Effective January 20, 1992		3,943,484	114,746	4,058,230
10.	ENERGY COST ADJUSTMENT CLAUSE (ECAC)				
11.	Fuel and Purchased Power		3,026,600	135,186	3,161,786
12.	Balancing Account		260,727	(269,033)	(8,306)
13.	Coolwater, D.91-10-030	5/	0	26,295	26,295
14.	Subtotal ECAC Rate Revenues		3,287,327	(107,552)	3,179,775
15.	ELECTRIC REVENUE ADJUSTMENT BILLING FACTOR (ERABF)				
16.	Balancing Account		4,251	108,319	112,570
17.	Palo Verde Unit 1		51,720	230	51,950
18.	Palo Verde Unit 2		53,137	(235)	52,902
19.	Palo Verde Unit 3		0	50,594	50,594
20.	Off-System Sales		(48,886)	16,905	(31,981)
21.	Subtotal ERABF Rate Revenues		60,222	175,813	236,035
22.	MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC)				
23.	SONGS 2 and 3 Pre-COD		0	0	0
24.	SONGS 2 and 3 Post-COD		32,591	(32,591)	0
25.	D.C. Expansion		11,336	0	11,336
26.	Subtotal MAAC Rate Revenues		43,927	(32,591)	11,336
27.	ANNUAL ENERGY RATE (AER)		0	0	0
28.	LOW-INCOME RATEPAYER ASSISTANCE (LIRA) PROGRAM		5,841	(12,057)	(6,216)
29.	TOTAL		7,340,801	138,359	7,479,160

1/ Based on January 1, 1991 authorized ALBRR ($3,937,547) and 1992 sales forecast.
2/ Includes reduction to revenue requirements adopted in 1992 Cost of Capital Proceeding D.91-11-059.
3/ These additions to ALBRR are effective for one year only per D.91-07-006 in I.90-07-037.
A.L. 913-E became effective October 18, 1991. A.L. 917-E-A became effective December 31, 1991.
4/ Included in 1992 ALBRR authorized by GRC D.91-12-076 , but is not effective until January 20, 1992.
5/ The authorized $78,886 is to be amortized over three years.

(END ATTACHMENT C)

ATTACHMENT D

SOUTHERN CALIFORNIA EDISON COMPANY ECAC
REVENUE DETAIL
Effective Date: January 20, 1992

CUSTOMER GROUP	SALES (GWH)	NET PRESENT REVENUES ($M) By Rate Schedule W/O LIRA or Facilities Rev.; Adj. for nonfirm	NET ADOPTED REVENUES ($M) By Rate Schedule W/O LIRA or Facilities Rev.; Adj. for nonfirm	NET ADOPTED REVENUE REQUIREMENT By Rate Schedule W/O LIRA ($M)	ADD: FACILITIES ($M)	ADOPTED REVENUE REQUIREMENT By Rate Schedule ($M)	CHANGE FROM PRESENT RATE REVENUE W/O LIRA ($M)	CHANGE FROM PRESENT RATE REVENUE W/O LIRA (%)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
DOMESTIC	22,298.3	2,624,295	2,696,834	2,696,834	0	2,696,834	72,539	2.8%
LIGHTING -SMP:								
GS-1, GS-1-APS, GS-1-PG	4,337.7	553,696		569,571	0	569,571	15,875	2.9%
TC-1	154.5	17,042		17,530	0	17,530	489	2.9%
TOTAL GS-1	4,492.2	570,737	587,101	587,101	0	587,101	16,364	2.9%
GS-2, GS-2-APS, S(GS-2)	20,278.4	2,163,970		2,234,839	0	2,234,839	70,869	3.3%
TOU-GS	52.1	5,979		6,175	15	6,190	196	3.3%
TOTAL GS-2	20,330.5	2,169,949	2,241,014	2,241,014	15	2,241,029	71,065	3.3%
TOTAL LIGHTING - SMP	24,822.7	2,740,686	2,828,115	2,828,115	15	2,828,130	87,429	3.2%
LARGE POWER:								
0-2 kV	7,293.7	681,069	675,527	675,527	0	675,527	(5,542)	-0.8%
2-50 kV	7,222.9	584,131	600,178	600,178	0	600,178	16,047	2.7%
50 + kV	6,559.8	421,245	403,654	403,654	0	403,654	(17,590)	-4.2%
TOTAL	21,076.4	1,686,445	1,679,360	1,679,360	0	1,679,360	(7,085)	-0.4%
AG & PUMPING:								
PA-1	1,093.2	110,130		112,389	0	112,389	2,258	2.1%
TOU-PA-1	118.6	10,745		10,965	0	10,965	220	2.1%
TOU-PA	286.2	25,819		26,349	79	26,428	529	2.1%
TOU-ALMP-2	171.2	16,875		17,221	0	17,221	346	2.1%
PA-2	542.5	50,839		51,881	0	51,881	1,043	2.1%
TOTAL AG & PUMPING	2,211.5	214,408	218,805	218,805	79	218,884	4,397	2.1%
SUBTOTAL	70,408.9	7,265,834	7,423,114	7,423,114	94	7,423,208	157,280	2.2%
ST & AREA LGT	470.3	36,659	29,795	29,795	32,372	62,168	(6,863)	-9.9%
TOTAL	70,879.2	7,302,493	7,452,910	7,452,910	32,466	7,485,376	150,417	2.1%

ATTACHMENT D

SOUTHERN CALIFORNIA EDISON COMPANY
REVENUE DETAIL
Effective Date: January 20, 1992

CUSTOMER GROUP	NET PRESENT BASE REVENUE REVENUE ($M)	NET ADOPTED BASE REVENUE REQUIREMENT ($M)	NET ADOPTED BASE REV REQ 100% EPMC ($M)	LESS: ADOPTED BASE REVENUE REQ: 100% EPMC ($M)	LESS: ADOPTED MAABF REV REQ 0.016 ($M)	LESS: ADOPTED AER REV REQ 0.000 ($M)	LESS: ADOPTED ERABF REV REQ 0.333 ($M)	LESS: ADOPTED CVBF REV REQ 0.000 ($M)	ADOPTED ECAC REVENUE REQUIREMENT ($M)	ADOPTED LIRA REV REQ 0.025 ($M)	TOTAL OFFSETS ($M)
	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
DOMESTIC	1,402,441		1,453,752	1,453,752	3,563	0	74,188	0	1,165,331	(18,092.0)	77,751
LIGHTING -SMP:											
GS-1, GS-1-APS, GS-1-PG	298,205		307,689	307,689	694	0	14,451	0	246,737	1,070.8	15,145
TC-1	8,522		8,793	8,793	25	0	515	0	8,197	38.1	539
TOTAL GS-1	306,728		316,482	316,482	719	0	14,966	0	254,935	1,108.9	15,684
GS-2, GS-2-APS, S(GS-2)	1,159,478		1,204,671	1,204,671	3,245	0	67,557	0	959,366	5,005.7	70,802
TOU-GS	3,241		3,367	3,382	8	0	174	0	2,626	12.9	182
TOTAL GS-2	1,162,718		1,208,038	1,208,053	3,253	0	67,731	0	961,992	5,018.5	70,984
TOTAL LIGHTING - SMP	1,469,446		1,524,520	1,524,535	3,972	0	82,697	0	1,216,927	6,127.4	86,668
LARGE POWER:											
0-2 kV	364,258		364,149	364,149	1,167	0	24,299	0	285,913	1,800.4	25,466
2-50 kV	308,899		323,531	323,531	1,156	0	24,063	0	251,428	1,783.0	25,219
50 + kV	225,789		217,593	217,593	1,050	0	21,854	0	163,158	1,619.3	22,903
TOTAL	898,946		905,274	905,274	3,372	0	70,216	0	700,498	5,202.7	73,588
AG & PUMPING:											
PA-1	62,620		67,132	67,132	175	0	3,642	0	41,440	269.9	3,817
TOU-PA-1	6,006		6,438	6,438	19	0	394	0	4,114	29.2	453.4
TOU-PA	13,252		14,207	14,286	46	0	953	0	11,142	70.6	999
TOU-ALMP-2	9,156		9,816	9,816	27	0	570	0	6,807	42.3	598
PA-2	26,644		28,564	28,564	87	0	1,807	0	21,423	133.9	1,896
TOTAL AG & PUMPING	117,678		126,157	126,236	354	0	7,368	0	84,927	545.9	7,721
SUBTOTAL	3,888,511		4,009,702	4,009,796	11,261	0	234,468	0	3,167,683	(6,216.0)	245,729
ST & AREA LGT	22,507		16,061	48,434	75	0	1,567	0	12,092	0.0	1,642
TOTAL	3,911,017	4,025,764	4,025,764	4,058,230	11,336	0	236,035	0	3,179,775	(6,216.0)	247,371
		4,058,230									7,485,376

SOUTHERN CALIFORNIA EDISON COMPANY
DEVELOPMENT OF LIRA REV REQ
ADOPTED JANUARY 20, 1992 COMBINED RATE CHANGE

RATE GROUP	GROSS SALES (GWH)	SALES NOT SUBJECT TO LIS (GWH)	LIS ADJUSTED SALES (GWH)	LIS (c/kWh)	LIS ($M)	LID ($M)
D	22,298.3	1,361.1 1/	20,937.2	0.0246848 2/	5,168.3	3/ (23,260.3)
GS-1	4,492.2	0.0	4,492.2	0.0246848	1,108.9	N/A
GS-2	20,330.5	0.0	20,330.5	0.0246848	5,018.5	N/A
TOTAL SMP	24,822.7	0.0	24,822.7	0.0246848	6,127.4	N/A
TOU-8-SEC	7,293.7	0.0	7,293.7	0.0246848	1,800.4	N/A
TOU-8-PRI	7,222.9	0.0	7,222.9	0.0246848	1,783.0	N/A
TOU-8-SUB	6,559.8	0.0	6,559.8	0.0246848	1,619.3	N/A
TOTAL TOU	21,076.4	0.0	21,076.4	0.0246848	5,202.7	N/A
AG	2,211.5	0.0	2,211.5	0.0246848	545.9	N/A
ST LGT	470.3	470.3	0.0	N/A	0.0	N/A
TOTAL	70,879.2	1,831.4	69,047.8	0.0246848	17,044.3	(23,260.3)

1/ (DE Sales X 25%) + DL Sales = 29.5 + 1,331.6 = 1,361.1 GWH

2/ LIS $23,260.3 + ($6,216.0) = $17,044.3 M Revenue Requirement
/ 69,047.8 GWH

0.01640745 0.00024685 = 0.00025 Dollars Per KWH LIS

3/ LID NON-MINIMUM

948.6	GWH	X	(0.01594)	=	($15,121.3)	M	D-LI BL SALES X D-LI BL LID
382.1	GWH	X	(0.02120)	=	($8,100.7)	M	D-LI NBL SALES X D-LI NBL LID
					($23,222.0)	M	D-LI DISCOUNT

LID MINIMUM

72,254	CUST MOS	X	(0.46)	=	($33.2)	M	D-LI DISCOUNT FOR BASE RATE MINIMUM
0.9	GWH	X	(0.00601) 4/	=	($5.1)	M	D-LI DISCOUNT FOR OFFSET RATES MINIMUM KWH
					($38.3)	M	D-LI DISCOUNT

4/ 15% OF BASELINE OFFSET RATES

(END ATTACHMENT D)

A.91-05-050 ALJ/RAB
CACD/MEB/2

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY

RATE ATTACHMENT

- RESIDENTIAL RATES
- SMALL AND MEDIUM POWER RATES
- LARGE POWER RATES AND INTERRUPTIBLE RATES
- AGRICULTURAL RATES
- STREETLIGHTING RATES

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
RATE LEVEL SUMMARY

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE $/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	TIME-RELATED DEMAND CHARGE ($/kW) Winter	NON-TIME-REL DEMAND CHARGE($/kW) 1/ Annual	ENERGY CHARGE (¢/kWh) BASE RATE Summer	ENERGY CHARGE (¢/kWh) BASE RATE Winter/Annual	ECABF Summer	ECABF Winter	2/ Other Offsets	TOTAL RATES 3/ Summer	TOTAL RATES 3/ Winter
DOMESTIC: *	D:	0.10 4/				13/							
	BL						3.441	8.356	6.839	1.924	0.349	10.629	10.629
	NBL						3.441	8.356	10.341	5.426	0.349	14.131	14.131
	TOU-D:	0.10 4/ 5/											
	ON						3.441	-	47.052	-	0.349	50.842	-
	MID						3.441	8.356	15.805	7.213	0.349	19.595	15.918
	OFF						3.441	8.356	3.519	(1.396)	0.349	7.309	7.309
	Baseline Credit =	3.502 ¢/kWh											
	D-LI: 7/	0.085 4/									6/		
	BL						3.441	8.356	6.839	1.924	(1.245)	9.035	9.035
	NBL						3.441	8.356	10.341	5.426	(1.771)	12.011	12.011
LIGHTING - SMALL & MEDIUM POWER:	GS-TP:	0.30						6.130	5.688	5.688	0.349	12.167	12.167
	GS-SP:	0.30						6.130	5.688	5.688	0.349	12.167	12.167
	GS-2:		37.45	10.35	3.25	-							
	1ST BLK **							3.881	5.701	5.701	0.349	9.931	9.931
	2ND BLK							3.881	0.770	0.770	0.349	5.000	5.000
	TC-1	0.30						4.906	5.306	5.306	0.349	10.561	10.561
	TOU-GS:		37.45 8/			3.25							
	ON			14.15	-			3.688	10.635	-	0.349	14.672	-
	MID			2.15	0.00			3.688	7.738	9.162	0.349	11.775	13.199
	OFF			0.00	0.00			3.688	0.963	0.963	0.349	5.000	5.000
LARGE POWER: *	TOU-8-SEC:		287.00			3.10							
	ON			15.20	-			3.124	7.820	-	0.349	11.293	-
	MID			2.40	0.00			3.124	5.590	6.686	0.349	9.063	10.159
	OFF			0.00	0.00			3.124	1.527	1.527	0.349	5.000	5.000
	TOU-8-PRI:		290.15			2.25							
	ON			15.05	-			3.243	7.403	-	0.349	10.995	-
	MID			2.25	0.00			3.243	5.224	6.313	0.349	8.816	9.905
	OFF			0.00	0.00			3.243	1.408	1.408	0.349	5.000	5.000
	TOU-8-SUB:		279.25			0.25							
	ON			12.55	-			2.756	4.454	-	0.349	7.559	-
	MID			1.95	0.00			2.756	2.955	3.704	0.349	6.060	6.809
	OFF			0.00	0.00			2.756	1.895	1.895	0.349	5.000	5.000
AGRICULTURAL & PUMPING:	PA-1 :		11.65	1.15 9/	1.15 9/			5.167	3.791	3.791	0.349	9.307	9.307
	PA-2:		23.30	8.30	1.35	-							
	1ST BLK **							4.079	5.720	5.720	0.349	10.148	10.148
	2ND BLK							4.079	0.572	0.572	0.349	5.000	5.000
	TOU-ALMP-2:		11.65										
	ON							5.707	17.056	-	0.349	23.112	-
	MID							5.707	-	16.973	0.349	-	23.029
	OFF							5.707	1.402	1.999	0.349	7.458	8.055

A.91-05-050 ALJ/RAB *
CACD/MEB/S

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
RATE LEVEL SUMMARY

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE $/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	TIME-RELATED DEMAND CHARGE ($/kW) Winter	NON-TIME- 1/ REL DEMAND CHARGE($/kW) Annual	ENERGY CHARGE (c/kWh) BASE RATE Summer	BASE RATE Winter/ Annual	ECABF Summer	ECABF Winter	2/ Other Offsets	TOTAL RATES 3/ Summer	TOTAL RATES 3/ Winter
	TOU-PA-1:		11.65	3.20 10/	3.20 10/								
	ON							3.980	5.997	-	0.349	10.326	-
	MID							3.980	-	5.710	0.349		10.039
	OFF							3.980	2.061	2.237	0.349	6.390	6.566
	TOU-PA (RATE A):		34.95 11/	1.15 9/	1.15 9/								
	ON							4.488	10.125	-	0.349	14.962	-
	MID							4.488	7.171	8.622	0.349	12.008	13.459
	OFF							4.488	0.163	0.163	0.349	5.000	5.000
	TOU-PA (RATE B):		34.95 11/			1.35							
	ON			6.95	-			3.593	10.938	-	0.349	14.880	-
	MID			0.00	0.00			3.593	8.000	9.443	0.349	11.942	13.385
	OFF			0.00	0.00			3.593	1.058	1.058	0.349	5.000	5.000
	TOU-PA-3 (RATE A):		34.95 11/	1.15 9/	1.15 9/								
	ON							4.488	10.348	-	0.349	15.185	-
	MID							4.488	7.350	8.823	0.349	12.187	13.660
	OFF							4.488	0.163	0.163	0.349	5.000	5.000
	TOU-PA-3 (RATE B):		34.95 11/			1.35							
	ON			6.95	-			4.121	10.240	-	0.349	14.710	-
	MID			0.00	0.00			4.121	7.336	8.763	0.349	11.806	13.233
	OFF			0.00	0.00			4.121	0.530	0.530	0.349	5.000	5.000
	TOU-PA-4 (RATE A):		34.95 11/	1.15 9/	1.15 9/								
	ON							4.488	10.300	-	0.349	15.137	-
	MID							4.488	7.311	8.779	0.349	12.148	13.616
	OFF							4.488	0.163	0.163	0.349	5.000	5.000
	TOU-PA-4 (RATE B):		34.95 11/			1.35							
	ON			6.95	-			4.115	10.191	-	0.349	14.655	-
	MID			0.00	0.00			4.115	7.298	8.719	0.349	11.762	13.183
	OFF			0.00	0.00			4.115	0.536	0.536	0.349	5.000	5.000
	TOU-PA-5 (>35KW MIN BILL): 11/					1.35							
	ON			6.95	-			4.079	4.802	-	0.349	9.230	-
	MID		23.30 12/	0.00	0.00			4.079	2.979	3.875	0.349	7.407	8.303
	OFF			0.00	0.00			4.079	2.381	2.429	0.349	6.809	6.857

1/ Maximum Demand Charge kW

	AE	CUBF	ERABF	MAABF
2/ Other Offsets = (c/kWh)	*	0.000	0.333	0.016

3/ The following charges are in addition to total rates: LIS = 0.025 c/kWh PUCRF = 0.012 c/kWh
4/ Minimum Charge
5/ Additional Meter charge at $0.15 /customer/day.
6/ Low Income Discoun (1.594)c/kWh for DL; (2.120)c/kWh for NBL is included.
7/ LIS of * 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 Charg $26.75 /kW of Contract Demand
Winter Monthly Minimum Charg $11.40 /kW of Contract Demand
13/ Annualized Base Rate used to determine when Minimum Charge is applic 6.621 c/kWh DLI = 5.628 c/kWh
* Domestic Seasonal Schedule DS: Summer season premium = 7.0 c/kWh
Winter season discount = 7.0 c/kWh

** First 300 kWh/kW
*** Subject to Rate Limiter: Ave Summer SEC = $0.17765 P[illegible] $0.17765
Summer On-pk SEC = $1.07831 P[illegible] $1.00567 SUB = $0.76108

Standby Schedule S : ($/StandbySEC = $3.10 PRI = $2.25 SUB = $0.25

5-050 ALJ/RAB *
C EB/S

ATTACHMENT E
SOUTHERN RNIA EDISON COMPANY
E LEVEL SUMMARY

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE ¢/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	TIME-RELATED DEMAND CHARGE ($/kW) Winter	NON-TIME-RELATED DEMA CHARGE ($/k Annual	ENERGY CHARGE (¢/kWh) Annual Base Rate	ECABF Summer	ECABF Winter	2/ Other Offsets	TOTAL RATES Summer	TOTAL RATES Winter
LARGE POWER:	I-5-A SEC:	287.00				3.10						
	ON			15.20	-		1.624	7.820	*	0.349	9.793	*
	MID			2.40	0.00		1.624	5.590	6.686	0.349	7.563	8.659
	OFF			0.00	0.00		1.624	0.527	0.527	0.349	2.500	2.500
	I-5-A PRI:	290.15				2.25						
	ON			15.05	-		1.743	7.403	*	0.349	9.495	*
	MID			2.25	0.00		1.743	5.224	6.313	0.349	7.316	8.405
	OFF			0.00	0.00		1.743	0.408	0.408	0.349	2.500	2.500
	I-5-A SUB:	279.25				0.25						
	ON			12.55	-		1.256	4.454	*	0.349	6.059	*
	MID			1.95	0.00		1.256	2.955	3.704	0.349	4.560	5.309
	OFF			0.00	0.00		1.256	0.895	0.895	0.349	2.500	2.500
	I-5-B SEC:	287.00				3.10						
	ON			15.20	-		3.124	7.820	*	0.349	11.293	*
	MID			2.40	0.00		3.124	5.590	6.686	0.349	9.063	10.159
	OFF			0.00	0.00		3.124	1.527	1.527	0.349	5.000	5.000
	OFF						3.124	(0.973)	(0.973)	0.349	2.500	2.500
	I-5-B PRI:	290.15				2.25						
	ON			15.05	-		3.243	7.403	*	0.349	10.995	*
	MID			2.25	0.00		3.243	5.224	6.313	0.349	8.816	9.905
	OFF			0.00	0.00		3.243	1.408	1.408	0.349	5.000	5.000
	OFF						3.243	(1.092)	(1.092)	0.349	2.500	2.500
	I-5-B SUB:	279.25				0.25						
	ON			12.55	-		2.756	4.454	*	0.349	7.559	*
	MID			1.95	0.00		2.756	2.955	3.704	0.349	6.060	6.809
	OFF			0.00	0.00		2.756	1.895	1.895	0.349	5.000	5.000
	OFF						2.756	(0.605)	(0.605)	0.349	2.500	2.500
	I-6-A SEC:	287.00				3.10						
	ON			10.65	-		2.666	7.580	*	0.349	10.595	*
	MID			1.70	0.00		2.666	5.508	6.581	0.349	8.523	9.596
	OFF			0.00	0.00		2.666	1.527	1.511	0.349	4.542	4.526
	I-6-A PRI:	290.15				2.25						
	ON			10.65	-		2.785	7.178	*	0.349	10.312	*
	MID			1.55	0.00		2.785	5.152	6.234	0.349	8.266	9.368
	OFF			0.00	0.00		2.785	1.408	1.392	0.349	4.542	4.526
	I-6-A SUB:	279.25				0.25						
	ON			8.30	-		2.298	4.285	*	0.349	6.932	*
	MID			1.30	0.00		2.298	2.932	3.667	0.349	5.579	6.314
	OFF			0.00	0.00		2.298	1.895	1.879	0.349	4.542	4.526
	I-6-B SEC:	287.00				3.10						
	ON			11.20	-		2.723	7.610	*	0.349	10.682	*
	MID			1.80	0.00		2.723	5.518	6.596	0.349	8.590	9.666
	OFF			0.00	0.00		2.723	1.527	1.513	0.349	4.599	4.585
	I-6-B PRI:	290.15				2.25						
	ON			11.20	-		2.842	7.206	*	0.349	10.397	*
	MID			1.65	0.00		2.842	5.161	6.244	0.349	8.352	9.435
	OFF			0.00	0.00		2.842	1.408	1.394	0.349	4.599	4.585
	I-6-B SUB:	279.25				0.25						
	ON			8.85	-		2.355	4.306	*	0.349	7.010	*
	MID			1.35	0.00		2.355	2.934	3.671	0.349	5.638	6.375
	OFF			0.00	0.00		2.355	1.895	1.881	0.349	4.599	4.585

1/ Maximum Demand Charge kW

2/ Other Offsets (¢/kWh) = AE CLMABF 0.000, ERABF 0.333, MAABF 0.016

3/ The following charges are in addition to total rates: LIS = 0.025 ¢/kWh; PUCRF = 0.012 ¢/kWh

A.91-05-050 ALJ/RAB *
CACD/MEB/5

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
RATE LEVEL SUMMARY

CUSTOMER GROUP	RATE SCHEDULE	CUSTOMER CHARGE ¢/Day	CUSTOMER CHARGE $/Mo	TIME-RELATED DEMAND CHARGE ($/kW) Summer	Spr/Fall	Winter	NON-TIME 1/ RELATED DEMAND CHARGE ($/kW) Annual	Base Rate	ECAMF Summer	Spr/Fall	Winter	4/ Other Offsets	TOTAL RATES 5/ Summer	Spr/Fall	Winter
LIGHTING & SMALL & MEDIUM POWER:	TOU-GS-SOP:		37.65 2/	41.15	*	*	3.25	2.709	7.987	*	*	0.349	11.045	*	*
	ON			1.10	0.55	0.55		2.709	7.987	5.318	6.156	0.349	11.045	8.376	9.214
	MID			0.00	0.00	0.00		2.709	4.229	4.718	4.718	0.349	7.287	7.776	7.776
	OFF			0.00	0.90	0.00		2.709	0.442	0.442	0.442	0.349	3.500	3.500	3.500
	OFF														
LARGE POWER:	TOU-8-SOP-SEC:		287.00	37.85	*	*	3.10	2.030	7.600	*	*	0.349	9.979	*	*
	ON			1.00	0.50	0.50		2.030	7.600	5.169	5.922	0.349	9.979	7.548	8.301
	MID			0.00	0.00	0.00		2.030	4.187	4.628	4.628	0.349	6.566	7.007	7.007
	OFF			0.00	0.00	0.00		2.030	1.121	1.121	1.121	0.349	3.500	3.500	3.500
	OFF														
	TOU-8-SOP-PRI:		290.15	38.25	*	*	2.25	2.129	7.172	*	*	0.349	9.650	*	*
	ON			1.00	0.50	0.50		2.129	7.172	4.841	5.572	0.349	9.650	7.319	8.050
	MID			0.00	0.00	0.00		2.129	3.809	4.317	4.317	0.349	6.287	6.795	6.795
	OFF			0.00	0.00	0.00		2.129	1.022	1.022	1.022	0.349	3.500	3.500	3.500
	OFF														
	TOU-8-SOP-SUB:		279.25	35.15	*	*	0.25	1.650	5.577	*	*	0.349	7.576	*	*
	ON			0.95	0.45	0.45		1.650	5.577	3.762	4.337	0.349	7.576	5.761	6.336
	MID			0.00	0.00	0.00		1.650	3.013	3.350	3.350	0.349	5.012	5.349	5.349
	OFF			0.00	0.00	0.00		1.650	1.501	1.501	1.501	0.349	3.500	3.500	3.500
	OFF														
	TOU-8-SOP-I-A-SEC:		287.00	27.05	*	*	3.10	1.873	7.411	*	*	0.349	9.633	*	*
	ON			0.65	0.35	0.35		1.873	7.411	5.106	5.855	0.349	9.633	7.328	8.077
	MID			0.00	0.00	0.00		1.873	4.032	4.556	4.563	0.349	6.254	6.778	6.785
	OFF			0.00	0.00	0.00		1.873	1.121	1.121	1.121	0.349	3.343	3.343	3.343
	OFF														
	TOU-8-SOP-I-A-PRI:		290.15	27.45	*	*	2.25	1.972	7.088	*	*	0.349	9.409	*	*
	ON			0.65	0.35	0.35		1.972	7.088	4.785	5.511	0.349	9.409	7.106	7.832
	MID			0.00	0.00	0.00		1.972	3.838	4.250	4.259	0.349	6.159	6.571	6.580
	OFF			0.00	0.00	0.00		1.972	1.022	1.022	1.022	0.349	3.343	3.343	3.343
	OFF														
	TOU-8-SOP-I-A-SUB:		279.25	24.80	*	*	0.25	1.493	5.504	*	*	0.349	7.346	*	*
	ON			0.65	0.30	0.30		1.493	5.504	3.715	4.286	0.349	7.346	5.557	6.128
	MID			0.00	0.00	0.00		1.493	2.971	3.293	3.301	0.349	4.813	5.135	5.143
	OFF			0.00	0.00	0.00		1.493	1.501	1.501	1.501	0.349	3.343	3.343	3.343
	OFF														
	TOU-8-SOP-I-B-SEC:		287.00	28.35	*	*	3.10	1.892	7.434	*	*	0.349	9.675	*	*
	ON			0.70	0.35	0.35		1.892	7.434	5.114	5.864	0.349	9.675	7.355	8.105
	MID			0.00	0.00	0.00		1.892	4.051	4.563	4.571	0.349	6.292	6.804	6.812
	OFF			0.00	0.00	0.00		1.892	1.121	1.121	1.121	0.349	3.362	3.362	3.362
	OFF														
	TOU-8-SOP-I-B-PRI:		290.15	28.75	*	*	2.25	1.991	7.099	*	*	0.349	9.439	*	*
	ON			0.70	0.35	0.35		1.991	7.099	4.792	5.519	0.349	9.439	7.132	7.859
	MID			0.00	0.00	0.00		1.991	3.845	4.259	4.266	0.349	6.185	6.599	6.606
	OFF			0.00	0.00	0.00		1.991	1.022	1.022	1.022	0.349	3.362	3.362	3.362
	OFF														
	TOU-8-SOP-I-B-SUB:		279.25	26.15	*	*	0.25	1.512	5.514	*	*	0.349	7.375	*	*
	ON			0.70	0.30	0.30		1.512	5.514	3.721	4.293	0.349	7.375	5.582	6.154
	MID			0.00	0.00	0.00		1.512	2.977	3.301	3.308	0.349	4.838	5.162	5.169
	OFF			0.00	0.00	0.00		1.512	1.501	1.501	1.501	0.349	3.362	3.362	3.362
	OFF														
AGRICULTURAL & PUMPING:	TOU-PA-SOP:		34.95 3/	38.40	*	*	1.35	1.802	6.996		*	0.349	9.165		*
	ON			0.00	0.00	0.00		1.802	4.483		4.673	0.349	6.636		6.826
	OFF			0.00	0.00	0.00		1.802	1.349		1.349	0.349	3.500		3.500
	OFF														

1/ Maximum Demand Charge kW
2/ Additional Meter charge at $7.00 /customer/month.
3/ Additional Meter charge at $6.00 /customer/month.

	AER	CLMABF	ERABF	MAABF
4/ Other Offsets = (¢/kWh)	0.000	0.000	0.333	0.016

5/ The following charges are in addition to total rates: LIS= 0.075 ¢/kWh
MICEF = 0.012 ¢/kWh

(END ATTACHMENT E)

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

LS-1
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A - ALL NIGHT SERVICE 1992

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)	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
INCANDESCENT LAMPS														
103	1,000	0.01327	0.02920	35.535	0.47166	1.03765	6.24	7.75	2,655	35,119	37,774	5,840	43,614	199.991
202	2,500	0.01327	0.02920	69.690	0.92501	2.03501	6.24	9.20	2,609	17,597	20,206	5,739	25,945	196.526
327	4,000	0.01327	0.02920	112.815	1.49742	3.29430	6.25	11.04	25,786	107,625	133,411	56,728	190,139	1,942.674
448	6,000	0.01327	0.02920	154.560	2.05151	4.51329	6.20	12.76	8,961	27,082	36,043	19,714	55,757	675.118
MERCURY VAPOR LAMPS														
100	4,000	0.01327	0.02920	45.195	0.59988	1.31973	6.23	8.15	4,089	42,464	46,553	8,995	55,548	308.049
175	7,900	0.01327	0.02920	74.520	0.98912	2.17605	6.20	9.37	40,451	253,555	294,006	88,992	382,978	3,047.570
250	12,000	0.01327	0.02920	103.845	1.37836	3.03236	6.23	10.64	5,855	26,465	32,320	12,881	45,201	441.134
400	21,000	0.01327	0.02920	163.530	2.17057	4.77522	6.61	13.56	34,252	104,306	138,558	75,353	213,911	2,580.503
700	41,000	0.01327	0.02920	277.035	3.67715	8.08966	6.67	18.44	1,897	3,442	5,339	4,174	9,513	142.950
1,000	55,000	0.01327	0.02920	391.575	5.19746	11.43433	6.67	23.30	249	320	569	549	1,118	18.796
HIGH PRESSURE SODIUM														
50	4,000	0.01327	0.02920	20.010	0.26560	0.58431	6.23	7.08	94,825	2,224,260	2,319,085	208,613	2,527,698	7,144.050
70	5,800	0.01327	0.02920	28.635	0.38008	0.83617	6.20	7.42	752,615	12,276,967	13,029,582	1,655,741	14,685,323	56,701.767
100	9,500	0.01327	0.02920	40.365	0.53577	1.17869	6.20	7.91	1,132,808	13,108,908	14,241,716	2,492,158	16,733,874	65,345.334
150	16,000	0.01327	0.02920	66.585	0.88380	1.94434	6.24	9.07	321,879	2,272,608	2,594,487	708,129	3,302,616	24,250.257
200	22,000	0.01327	0.02920	84.870	1.12650	2.47828	6.60	10.20	789,410	4,625,042	5,414,452	1,736,688	7,151,140	59,473.841
250	27,500	0.01327	0.02920	107.985	1.43331	3.15326	6.62	11.21	143,755	663,960	807,715	316,259	1,123,974	10,830.464
400	50,000	0.01327	0.02920	167.325	2.22094	4.88604	6.70	13.81	53,489	161,363	214,852	117,675	332,527	4,029.855
LOW PRESSURE SODIUM														
35	4,800	0.01327	0.02920	21.735	0.28849	0.63468	6.77	7.69	3	81	84	8	92	0.261
55	8,000	0.01327	0.02920	28.980	0.38466	0.84624	6.77	8.00	33,304	586,147	619,451	73,268	692,719	2,509.088
90	13,500	0.01327	0.02920	45.195	0.59988	1.31973	7.70	9.62	785	10,072	10,857	1,726	12,583	59.115
135	22,500	0.01327	0.02920	62.790	0.83343	1.83352	7.97	10.64	11,321	108,264	119,585	24,907	144,492	852.939
180	33,000	0.01327	0.02920	79.005	1.04865	2.30702	7.72	11.08	0	0	0	0	0	0.000
						TOTAL ALL NIGHT			3,460,998	36,655,647	40,116,645	7,614,137	47,730,782	260,750.282

* : Includes PUC Reimbursement fee

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

LS-1
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B - MIDNIGHT SERVICE 1992

WATTS	LUMENS	BASE ENERGY RATE (1)	OFFSET ENERGY RATE (2)	KWH PER MONTH (3)	BASE ENERGY CHG. (1)*(3) (4)	OFFSET ENERGY CHG. (2)*(3) (5)	NON-ENERGY CHARGE RATE (6)	TOTAL ($/LAMP-MO) (4+5+6) (7)
INCANDESCENT LAMPS								
103	1,000	0.02072	0.02920	17.943	0.37184	0.52395	6.24	7.14
202	2,500	0.02072	0.02920	35.188	0.72921	1.02752	6.24	8.00
327	4,000	0.02072	0.02920	56.963	1.18046	1.66337	6.25	9.09
448	6,000	0.02072	0.02920	78.042	1.61728	2.27889	6.20	10.10
MERCURY VAPOR LAMPS								
100	4,000	0.02072	0.02920	22.820	0.47290	0.66636	6.23	7.37
175	7,900	0.02072	0.02920	37.627	0.77975	1.09874	6.20	8.08
250	12,000	0.02072	0.02920	52.434	1.08660	1.53112	6.23	8.85
400	21,000	0.02072	0.02920	82.571	1.71114	2.41115	6.61	10.73
700	41,000	0.02072	0.02920	139.883	2.89883	4.08471	6.67	13.65
1,000	55,000	0.02072	0.02920	197.717	4.09733	5.77351	6.67	16.54
HIGH PRESSURE SODIUM								
50	4,000	0.02072	0.02920	10.104	0.20939	0.29505	6.23	6.73
70	5,800	0.02072	0.02920	14.459	0.29964	0.42222	6.20	6.92
100	9,500	0.02072	0.02920	20.381	0.42236	0.59514	6.20	7.22
150	16,000	0.02072	0.02920	33.621	0.69674	0.98176	6.24	7.92
200	22,000	0.02072	0.02920	42.853	0.88805	1.25135	6.60	8.74
250	27,500	0.02072	0.02920	54.525	1.12993	1.59218	6.62	9.34
400	50,000	0.02072	0.02920	84.487	1.75084	2.46709	6.70	10.92
LOW PRESSURE SODIUM								
35	4,800	0.02072	0.02920	10.975	0.22744	0.32048	6.77	7.32
55	8,000	0.02072	0.02920	14.633	0.30324	0.42730	6.77	7.50
90	13,500	0.02072	0.02920	22.820	0.47290	0.66636	7.70	8.84
135	22,500	0.02072	0.02920	31.704	0.65701	0.92578	7.97	9.55
180	33,000	0.02072	0.02920	39.892	0.82669	1.16488	7.72	9.71

WATTS	LUMENS	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
INCANDESCENT LAMPS							
103	1,000	0	0	0	0	0	0.000
202	2,500	0	0	0	0	0	0.000
327	4,000	0	0	0	0	0	0.000
448	6,000	0	0	0	0	0	0.000
MERCURY VAPOR LAMPS							
100	4,000	0	0	0	0	0	0.000
175	7,900	0	0	0	0	0	0.000
250	12,000	0	0	0	0	0	0.000
400	21,000	0	0	0	0	0	0.000
700	41,000	0	0	0	0	0	0.000
1,000	55,000	0	0	0	0	0	0.000
HIGH PRESSURE SODIUM							
50	4,000	0	0	0	0	0	0.000
70	5,800	0	0	0	0	0	0.000
100	9,500	0	0	0	0	0	0.000
150	16,000	0	0	0	0	0	0.000
200	22,000	0	0	0	0	0	0.000
250	27,500	0	0	0	0	0	0.000
400	50,000	0	0	0	0	0	0.000
LOW PRESSURE SODIUM							
35	4,800	0	0	0	0	0	0.000
55	8,000	0	0	0	0	0	0.000
90	13,500	0	0	0	0	0	0.000
135	22,500	0	0	0	0	0	0.000
180	33,000	0	0	0	0	0	0.000
TOTAL MIDNIGHT		0	0	0	0	0	0.000

TIMED AUXILLIARY POWER DEVICE

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG.	OFFSET ENERGY CHG.	NON-ENERGY CHARGE RATE	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
DEVICE CHARGES	0.02072	0.02920	44	0.911822015	1.284838474	11.09	1,368	16,635	18,003	1,927	19,930	66.000
CUSTOMER CHARGES						65.00	0	1,950	1,950	0	1,950	0.000
TOTAL LS-1							3,462,366	36,674,232	40,136,598	7,616,064	47,752,662	260,816.282

* : Includes PUC Reimbursement fee

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

LS-2
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A - MULTIPLE SERVICE/ALL NIGHT 1992

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)	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
INCANDESCENT LAMPS														
103	1,000	0.01327	0.02920	35.535	0.47166	1.03765	0.79	2.30	583	976	1,559	1,283	2,842	43.921
202	2,500	0.01327	0.02920	69.690	0.92501	2.03501	0.79	3.75	2,209	1,887	4,096	4,860	8,956	166.420
327	4,000	0.01327	0.02920	112.815	1.49742	3.29430	0.79	5.58	6,738	3,555	10,293	14,824	25,117	507.668
448	6,000	0.01327	0.02920	154.560	2.05151	4.51329	0.79	7.35	1,403	540	1,943	3,087	5,030	105.719
690	10,000	0.01327	0.02920	238.050	3.15969	6.95127	0.79	10.90	1,024	256	1,280	2,252	3,532	77.128
MERCURY VAPOR LAMPS														
100	4,000	0.01327	0.02920	45.195	0.59988	1.31973	0.79	2.71	13,368	17,604	30,972	29,409	60,381	1,007.125
175	7,900	0.01327	0.02920	74.520	0.98912	2.17605	0.79	3.96	24,214	19,339	43,553	53,270	96,823	1,824.250
250	12,000	0.01327	0.02920	103.845	1.37836	3.03236	0.79	5.20	9,742	5,584	15,326	21,433	36,759	733.976
400	21,000	0.01327	0.02920	163.530	2.17057	4.77522	0.79	7.74	135,756	49,410	185,166	298,661	483,827	10,227.820
700	41,000	0.01327	0.02920	277.035	3.67715	8.08966	0.79	12.56	66,498	14,286	80,784	146,293	227,077	5,009.901
1,000	55,000	0.01327	0.02920	391.575	5.19746	11.43433	0.79	17.42	8,545	1,299	9,844	18,798	28,642	643.749
HIGH PRESSURE SODIUM														
50	4,000	0.01327	0.02920	20.010	0.26560	0.58431	0.79	1.64	4,156	12,362	16,518	9,143	25,661	313.116
70	5,800	0.01327	0.02920	28.635	0.38008	0.83617	0.79	2.01	51,698	107,456	159,154	113,735	272,889	3,894.933
100	9,500	0.01327	0.02920	40.365	0.53577	1.17869	0.79	2.50	50,971	75,157	126,128	112,136	238,264	3,840.165
150	16,000	0.01327	0.02920	66.585	0.88380	1.94434	0.79	3.62	78,375	70,057	148,432	172,424	320,856	5,904.758
200	22,000	0.01327	0.02920	84.870	1.12650	2.47828	0.79	4.39	216,180	151,604	367,784	475,592	843,376	16,286.892
250	27,500	0.01327	0.02920	107.985	1.43331	3.15326	0.79	5.38	232,987	128,416	361,403	512,568	873,971	17,553.178
310	37,000	0.01327	0.02920	132.135	1.75386	3.85846	0.79	6.40	17,805	8,020	25,825	39,171	64,996	1,341.435
400	50,000	0.01327	0.02920	167.325	2.22094	4.88604	0.79	7.90	146,955	52,273	199,228	323,299	522,527	11,071.561
LOW PRESSURE SODIUM														
35	4,800	0.01327	0.02920	21.735	0.28849	0.63468	0.79	1.71	1,485	4,067	5,552	3,267	8,819	111.892
55	8,000	0.01327	0.02920	28.980	0.38466	0.84624	0.79	2.02	28,789	59,127	87,916	63,336	151,252	2,168.979
90	13,500	0.01327	0.02920	45.195	0.59988	1.31973	0.79	2.71	842	1,109	1,951	1,853	3,804	63.454
135	22,500	0.01327	0.02920	62.790	0.83343	1.83352	0.79	3.46	24,333	23,065	47,398	53,532	100,930	1,833.217
180	33,000	0.01327	0.02920	79.005	1.04865	2.30702	0.79	4.15	10,860	8,181	19,041	23,891	42,932	818.176
									1,135,516	815,630	1,951,146	2,498,117	4,449,263	85,549.433

* : Includes PUC Reimbursement fee

A.91-05-050 ALJ/RAB *
CACO/MEB/5

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

LS-2
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B - MULTIPLE SERVICE/MIDNIGHT 1992

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)	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
INCANDESCENT LAMPS														
103	1,000	0.02072	0.02920	18.633	0.38614	0.54410	0.79	1.72	0	0	0	0	0	0.000
202	2,500	0.02072	0.02920	36.542	0.75727	1.06706	0.79	2.61	0	0	0	0	0	0.000
327	4,000	0.02072	0.02920	59.154	1.22586	1.72735	0.79	3.74	0	0	0	0	0	0.000
448	6,000	0.02072	0.02920	81.043	1.67947	2.36653	0.79	4.84	0	0	0	0	0	0.000
690	10,000	0.02072	0.02920	124.821	2.58669	3.64488	0.79	7.02	0	0	0	0	0	0.000
MERCURY VAPOR LAMPS														
100	4,000	0.02072	0.02920	23.698	0.49110	0.69200	0.79	1.97	0	0	0	0	0	0.000
175	7,900	0.02072	0.02920	39.074	0.80974	1.14099	0.79	2.74	68	66	134	96	230	3.282
250	12,000	0.02072	0.02920	54.451	1.12840	1.59002	0.79	3.51	68	47	115	95	210	3.267
400	21,000	0.02072	0.02920	85.747	1.77695	2.50389	0.79	5.07	362	161	523	511	1,034	17.492
700	41,000	0.02072	0.02920	145.263	3.01032	4.24181	0.79	8.04	0	0	0	0	0	0.000
1,000	55,000	0.02072	0.02920	205.322	4.25493	5.99558	0.79	11.04	0	0	0	0	0	0.000
HIGH PRESSURE SODIUM														
50	4,000	0.02072	0.02920	10.492	0.21743	0.30638	0.79	1.31	0	0	0	0	0	0.000
70	5,800	0.02072	0.02920	15.015	0.31116	0.43845	0.79	1.54	146	370	516	205	721	7.027
100	9,500	0.02072	0.02920	21.165	0.43861	0.61804	0.79	1.85	576	1,033	1,607	808	2,415	27.684
150	16,000	0.02072	0.02920	34.914	0.72353	1.01952	0.79	2.53	52	57	109	73	182	2.514
200	22,000	0.02072	0.02920	44.501	0.92220	1.29947	0.79	3.01	476	408	884	671	1,555	22.963
250	27,500	0.02072	0.02920	56.622	1.17339	1.65341	0.79	3.62	56	38	94	79	173	2.718
310	37,000	0.02072	0.02920	69.285	1.43581	2.02318	0.79	4.25	0	0	0	0	0	0.000
400	50,000	0.02072	0.02920	87.737	1.81819	2.56200	0.79	5.17	0	0	0	0	0	0.000
LOW PRESSURE SODIUM														
35	4,800	0.02072	0.02920	11.397	0.23618	0.33280	0.79	1.36	0	0	0	0	0	0.000
55	8,000	0.02072	0.02920	15.196	0.31491	0.44374	0.79	1.55	91	228	319	128	447	4.376
90	13,500	0.02072	0.02920	23.698	0.49110	0.69200	0.79	1.97	0	0	0	0	0	0.000
135	22,500	0.02072	0.02920	32.924	0.68229	0.96141	0.79	2.43	41	47	88	58	146	1.975
180	33,000	0.02072	0.02920	41.426	0.85848	1.20968	0.79	2.86	0	0	0	0	0	0.000
									1,934	2,455	4,389	2,724	7,113	93.298
							TOTAL LS-2 MULTIPLE		1,137,450	818,085	1,955,535	2,500,841	4,456,376	85,642.731

* ‡ Includes PUC Reimbursement fee

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

LS-2
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C - SERIES SERVICE/ALL NIGHT 1992

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)	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
INCANDESCENT LAMPS														
103	1,000	0.01327	0.02920	29.528	0.39193	0.86224	3.55	4.80	4,416	40,001	44,417	9,716	54,133	332.722
202	2,500	0.01327	0.02920	64.567	0.85701	1.88541	3.55	6.29	18,974	78,597	97,571	41,743	139,314	1,429.513
327	4,000	0.01327	0.02920	97.638	1.29597	2.85111	3.55	7.70	11,057	30,289	41,346	24,326	65,672	833.047
448	6,000	0.01327	0.02920	136.614	1.81331	3.98925	3.55	9.35	5,875	11,502	17,377	12,925	30,302	442.629
690	10,000	0.01327	0.02920	227.559	3.02044	6.64492	3.55	13.22	254	298	552	558	1,110	19.115
MERCURY VAPOR LAMPS														
100	4,000	0.01327	0.02920	51.675	0.68589	1.50896	3.55	5.74	17,992	93,124	111,116	39,583	150,699	1,355.539
175	7,900	0.01327	0.02920	85.574	1.13584	2.49884	3.55	7.18	14,543	45,454	59,997	31,995	91,992	1,095.689
250	12,000	0.01327	0.02920	117.819	1.56384	3.44042	3.55	8.55	6,061	13,760	19,821	13,335	33,156	456.666
400	21,000	0.01327	0.02920	183.963	2.44178	5.37188	3.55	11.36	210,999	306,763	517,762	464,195	981,957	15,896.611
700	41,000	0.01327	0.02920	314.184	4.17024	9.17445	3.55	16.89	115,749	98,534	214,283	254,646	468,929	8,720.491
1,000	55,000	0.01327	0.02920	442.338	5.87125	12.91666	3.55	22.34	11,484	6,944	18,428	25,265	43,693	865.213
HIGH PRESSURE SODIUM														
50	4,000	0.01327	0.02920	30.746	0.40810	0.89781	3.55	4.86	22,013	191,487	213,500	48,428	261,928	1,658.439
70	5,800	0.01327	0.02920	40.834	0.54200	1.19239	3.55	5.28	27,018	176,960	203,978	59,438	263,416	2,035.493
100	9,500	0.01327	0.02920	58.128	0.77155	1.69739	3.55	6.02	14,267	65,647	79,914	31,388	111,302	1,074.903
150	16,000	0.01327	0.02920	83.590	1.10951	2.44090	3.55	7.10	14,113	45,156	59,269	31,048	90,317	1,063.265
200	22,000	0.01327	0.02920	111.933	1.48571	3.26854	3.55	8.30	51,382	122,773	174,155	113,039	287,194	3,871.091
LOW PRESSURE SODIUM														
35	4,800	0.01327	0.02920	24.225	0.32154	0.70739	3.55	4.58	675	7,455	8,130	1,486	9,616	50.873
55	8,000	0.01327	0.02920	34.200	0.45394	0.99867	3.55	5.00	59,599	466,087	525,686	131,117	656,803	4,490.186
90	13,500	0.01327	0.02920	61.750	0.81962	1.80315	3.55	6.17	2,105	9,116	11,221	4,630	15,851	158.574
135	22,500	0.01327	0.02920	87.875	1.16638	2.56603	3.55	7.28	39,568	120,430	159,998	87,050	247,048	2,981.072
180	33,000	0.01327	0.02920	104.025	1.38075	3.03762	3.55	7.97	8,467	21,769	30,236	18,627	48,863	637.881
									656,611	1,952,146	2,608,757	1,444,538	4,053,295	49,469.012

* : Includes PUC Reimbursement fee

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

LS-2
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D - SERIES SERVICE/MIDNIGHT 1992

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)	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
INCANDESCENT LAMPS														
103	1,000	0.02072	0.02920	15.488	0.32096	0.45226	3.55	4.32	0	0	0	0	0	0.000
202	2,500	0.02072	0.02920	33.866	0.70181	0.98892	3.55	5.24	34	170	204	47	251	1.626
327	4,000	0.02072	0.02920	51.212	1.06128	1.49544	3.55	6.11	0	0	0	0	0	0.000
448	6,000	0.02072	0.02920	71.656	1.48494	2.09242	3.55	7.13	0	0	0	0	0	0.000
690	10,000	0.02072	0.02920	119.357	2.47346	3.48533	3.55	9.51	0	0	0	0	0	0.000
MERCURY VAPOR LAMPS														
100	4,000	0.02072	0.02920	27.113	0.56187	0.79172	3.55	4.90	0	0	0	0	0	0.000
175	7,900	0.02072	0.02920	44.898	0.93043	1.31106	3.55	5.79	0	0	0	0	0	0.000
250	12,000	0.02072	0.02920	61.817	1.28105	1.80511	3.55	6.64	676	1,874	2,550	953	3,503	32.639
400	21,000	0.02072	0.02920	96.521	2.00023	2.81850	3.55	8.37	0	0	0	0	0	0.000
700	41,000	0.02072	0.02920	164.844	3.41610	4.81359	3.55	11.78	0	0	0	0	0	0.000
1,000	55,000	0.02072	0.02920	232.083	4.80951	6.77703	3.55	15.14	0	0	0	0	0	0.000
HIGH PRESSURE SODIUM														
50	4,000	0.02072	0.02920	16.134	0.33435	0.47113	3.55	4.36	217	2,300	2,517	305	2,822	10.455
70	5,800	0.02072	0.02920	21.429	0.44408	0.62575	3.55	4.62	0	0	0	0	0	0.000
100	9,500	0.02072	0.02920	30.504	0.63214	0.89074	3.55	5.07	0	0	0	0	0	0.000
150	16,000	0.02072	0.02920	43.865	0.90902	1.28090	3.55	5.74	949	3,706	4,655	1,337	5,992	45.795
200	22,000	0.02072	0.02920	58.739	1.21726	1.71523	3.55	6.48	102	298	400	144	544	4.934
LOW PRESSURE SODIUM														
35	4,800	0.02072	0.02920	12.709	0.26337	0.37111	3.55	4.18	0	0	0	0	0	0.000
55	8,000	0.02072	0.02920	17.942	0.37182	0.52392	3.55	4.45	4,663	44,517	49,180	6,570	55,750	224.993
90	13,500	0.02072	0.02920	32.396	0.67135	0.94599	3.55	5.17	48	256	304	68	372	2.333
135	22,500	0.02072	0.02920	46.102	0.95538	1.34622	3.55	5.85	871	3,238	4,109	1,228	5,337	42.045
180	33,000	0.02072	0.02920	54.575	1.13097	1.59364	3.55	6.27	0	0	0	0	0	0.000
									7,560	56,359	63,919	10,652	74,571	364.820
							TOTAL LS-2 SERIES		664,171	2,008,505	2,672,676	1,455,190	4,127,866	49,833.832
NON STANDARD LAMPS														
ALL NIGHT MULT		0.01327	0.02920	74.421	0.98781	2.17316	0.79	3.95	43,278	34,611	77,889	95,210	173,099	3,260.533
ALL NIGHT SERIES		0.01327	0.02920	113.793	1.51040	3.32286	3.55	8.38	72,771	171,039	243,810	160,095	403,905	5,482.547
MIDNIGHT MULT		0.02072	0.02920	38.887	0.80586	1.13553	0.79	2.73	1,518	1,488	3,006	2,139	5,145	73.263
MIDNIGHT SERIES		0.02072	0.02920	59.077	1.22427	1.72510	3.55	6.50	0	0	0	0	0	0.000
							TOTAL LS-2 NONSTD		117,567	207,138	324,705	257,444	582,149	8,816.343
POWER FACTOR REVENUES					RATE PER KVAR		0.30		-	157,396	157,396	-	157,396	-
								TOTAL LS-2	1,919,188	3,191,124	5,110,312	4,213,475	9,323,787	144,292.906

* : Includes PUC Reimbursement fee

A.91-05-050 ALJ/RAB *
CACD/MEB/S

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

LS-3 1992

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH ANNUAL GWH	BASE ENERGY CHG. (1 * 3)	OFFSET ENERGY CHG. (2 * 3)	CUSTOMER CHARGE RATE	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
	(1)	(2)										
TOTAL ENERGY	0.01327	0.02920	50.993	676,842	1,489,040		676,842	0	676,842	1,489,040	2,165,882	50,993.000
CUSTOMER CHARGE												
MULTIPLE	0.00000	0.00000	0			8.65	0	370,462	370,462	0	370,462	
SERIES	0.00000	0.00000	0			109.35	0	111,537	111,537	0	111,537	
TOTAL ENERGY AND CUSTOMER CHARGE							676,842	481,999	1,158,841	1,489,040	2,647,881	50,993.000
RELAMPING	0.00000	0	0	0	0	0.41	0	787	787	0	787	
TOTAL LS-3							676,842	482,786	1,159,628	1,489,040	2,648,668	50,993.000

* : Includes PUC Reimbursement fee

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

OL-1 1992 — 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)	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
MERCURY VAPOR LAMPS														
175	7,900	0.01327	0.02920	74.520	0.98912	2.17605	5.09	8.26	131	672	803	287	1,090	9.837
400	21,000	0.01327	0.02920	168.460	2.23601	4.91918	5.50	12.66	27	66	93	59	152	2.022
HIGH PRESSURE SODIUM														
70	5,800	0.01327	0.02920	28.635	0.38008	0.83617	5.09	6.31	23,170	310,286	333,456	50,973	384,429	1,745.590
100	9,500	0.01327	0.02920	40.365	0.53577	1.17869	5.09	6.80	48,863	464,208	513,071	107,497	620,568	3,681.288
200	22,000	0.01327	0.02920	84.870	1.12650	2.47828	5.49	9.09	83,744	408,127	491,871	184,235	676,106	6,309.236
							TOTAL ALL NIGHT		155,935	1,183,359	1,339,294	343,051	1,682,345	11,747.973

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)	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
MERCURY VAPOR LAMPS														
175	7,900	0.02072	0.02920	37.627	0.77975	1.09874	5.09	6.97	0	0	0	0	0	0.000
400	21,000	0.02072	0.02920	82.571	1.71114	2.41115	5.50	9.62	0	0	0	0	0	0.000
HIGH PRESSURE SODIUM														
70	5,800	0.02072	0.02920	14.459	0.29964	0.42222	5.09	5.81	0	0	0	0	0	0.000
100	9,500	0.02072	0.02920	20.381	0.42236	0.59514	5.09	6.11	0	0	0	0	0	0.000
200	22,000	0.02072	0.02920	42.853	0.88805	1.25135	5.49	7.63	0	0	0	0	0	0.000
							TOTAL MIDNIGHT		0	0	0	0	0	0.000
							OL-1 LAMP TOTAL		155,935	1,183,359	1,339,294	343,051	1,682,345	11,747.973
OL-1 POLE CHARGE														
	STANDARD POLES						2.20		0	171,917	171,917	0	171,917	
							TOTAL OL-1		155,935	1,355,276	1,511,211	343,051	1,854,262	11,747.973

* : Includes PUC Reimbursement fee

ATTACHMENT E
SOUTHERN CALIFORNIA EDISON COMPANY
EFFECTIVE DATE: JANUARY 20, 1992

DWL 1992

	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)	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
	(1)	(2)	(3)	(4)	(5)	(6)	(7)						
RATE A	0.01327	0.02920	32.341	0.42927	0.94439	6.55	7.92	30,866	470,971	501,837	67,905	569,742	2,325.447
RATE B	0.01327	0.02920	32.341	0.42927	0.94439	2.15	3.52	2,004	10,036	12,040	4,408	16,448	150.968
RATE C	0.00000	0.00000	0.000	0.00000	0.00000	0.40	0.40	0	1,867	1,867	0	1,867	0.000
TOTAL DWL								32,870	482,874	515,744	72,313	588,057	2,476.415

(END ATTACHMENT E)

	BASE ENERGY REVENUES	NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL MWH
STREETLIGHT TOTAL	6,247,201	42,186,292	48,433,493	13,733,943	62,167,436	470,326.576

	FACILITIES REVENUES	OFFSET REVENUES	TOTAL REVENUES
STREETLIGHT TOTAL (1)	42,186,292	13,733,943	62,167,436
LESS FACIL. ADJ.(2)	(9,814,029)		
SUB TOTAL	32,372,263	13,733,943	62,167,436
REVENUE REQUIREMENT	32,372,263	13,733,947	62,167,694
RATE SHORTFALL	0	(4)	(258)

* : Includes PUC Reimbursement fee

(END ATTACHMENT E)

ATTACHMENT F

Edison's Proposed Changes to Preliminary Statement

A. Historical Energy Cost Adjustment Billing Factors (ECABF)

Edison proposes that Preliminary Statement, Part G.5, be modified to remove: (1) the table entitled "Energy Cost Adjustment Billing Factors Per KWh Applicable to Domestic Service Rate Schedules"; and (2) the sentence prior to the table which references it.

B. Historical Annual Energy Rates (AER)

Edison proposes that Preliminary Statement, Part G.8.k, be modified to show only the AERs for the last five rate change effective dates.

C. Electric Revenue Adjustment Mechanism

Edison proposes that the following section be added to Edison's Preliminary Statement, Part J.4:

> g. Plus: Intervenor compensation payments authorized by the Commission, recorded during the month, increased to provide for Franchise Fees and Uncollectible Accounts.

D. Interim Major Additions Billing Factor

Edison proposes that Section J.4.b be deleted.

E. Ratemaking Adjustment Associated with Palo Verde Nuclear Generating Station

Edison proposes that Preliminary Statement, J.4.d, in its currently effective tariffs, be deleted.

F. Conservation Load Management Adjustment Clause

Edison proposes that Preliminary Statement, Part I, be deleted in its entirety.

(END OF ATTACHMENT F)