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Decision 88 09 031 SEP 14 1988

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of the Southern California Edison Company (U 338-E) for: (1) Authority to Increase Its Energy Cost Adjustment Billing Factors, Increase Its Annual Energy Rate, and Increase Its Electric Revenue Adjustment Billing Factor Effective June 1, 1988; (2) Authority to Implement Modifications to its Energy Cost Adjustment Clause as More Specifically Set Forth in this Application; (3) Authority to Revise the Incremental Energy Rate, the Energy Reliability Index, and Avoided Cost Pricing; (4) Review of the Reasonableness of Edison's Operations During the Period from December 1, 1986, through November 30, 1987; and (5) Review of the Reasonableness of Edison Payments to Qualifying Facilities Under Nonstandard Contracts During the Period from December 1, 1984, through November 30, 1987.	Application 88-02-016 (Filed February 11, 1988)

(See Appendix A for appearances.)

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O P I N I O N

Phase I: Forecast Phase
Revenue Requirements and QF Payments

A. Summary

This decision authorizes an increase of $382 million in the Energy Cost Adjustment Clause (ECAC) of the Southern California Edison Company (Edison). This increase is comprised of a $424 million increase in ECAC, a zero increase in Edison's Annual Energy Rate (AER), and a $42 million decrease in Edison's Electric Revenue Adjustment Mechanism (ERAM). This increase is based on present rate revenues before the $200 million interim increase adopted in this proceeding in D.88-05-074.

Because this decision also adjusts base rate and other rate elements to reflect increased sales, the overall authorized revenue increase is $376 million. With the $200 million increase authorized in D.88-05-074, net customer rates will increase by $176 million.

Additionally, the rate increase resulting from this order will reflect the new baseline and Tier II residential rates adopted today in Order Instituting Investigation (I.) 88-07-009. This investigation was instituted for the purpose of implementing Senate Bill 987 which requires realignment of residential rates by November 1, 1988. To ensure compliance with this legislation and to coincide with seasonal changes in most of Edison's rates, the effective date of the rate increase authorized by this decision is October 1, 1988.

The Commission concludes that the petition to set aside submission and reopen hearings in the forecast phase filed by Edison on August 31, 1988, should be denied. We find, however, that some relief should be accorded Edison based on the changes in gas availability occurring after the issuance of the Administrative

Law Judge's (ALJ's) proposed decision on August 12, 1988. This relief is in the form of the continued suspension of Edison's AER until November 1, 1988. The AER was originally suspended on May 25, 1988, in D.88-05-074. The reinstatement of Edison's AER on November 1, 1988, coincides with the termination of this Commission's emergency order in I.88-08-052 which adopted emergency measures designed to assist Edison, among others, to meet their gas needs before November 1.

Effective November 1, 1988, Edison's AER mechanism will be reinstated by advice letter filing. AER revenues will be $217 million, offset by a $217 million reduction to ECAC revenues. There will be no immediate effect on customer rates.

This decision adopts a revenue allocation based on a weighted average of 1/3 Equal Percent of Marginal Cost and 2/3 System Average Percentage Change with a 2.5% cap over the system average percentage change for all customer groups. The total percentage increase for Edison's domestic customers is 9.5%, resulting in a 5.6% increase over the interim rates adopted in D.88-05-074.

B. Background

By this application, the Southern California Edison Company (Edison) originally requested an increase of $627.9 million in its electric rates on an annualized basis effective June 1, 1988. This requested increase of approximately 11.6 percent above present rate levels was based on revenue requirement increases related to Edison's Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), and Electric Revenue Adjustment Mechanism (ERAM). Additionally, Edison sought approval of the reasonableness of its operations for the 1987 reasonableness review period and the reasonableness of its nonstandard contracts with qualifying facilities for a three-year period beginning December 1, 1984.

In revisions to its ECAC filing based on more recent resource mix, energy price, and recorded balancing account information, Edison first reduced its requested revenue requirement to $484.1 million on March 28, 1988. On May 14, 1988, Edison submitted additional prepared testimony further reducing this request to $479.4 million. In a brief filed on June 24, 1988, Edison states that its final proposed annual revenue increase is $456 million, a system average percentage increase of 8.4%.

Following a prehearing conference on February 26, 1988, an Administrative Law Judge (ALJ) ruling was issued on March 2, 1988, bifurcating this proceeding into two phases. The first phase was to consider those issues relating to the forecasts of fuel costs and resource mix and variable payments to qualifying facilities. The second phase, to be heard following the issuance of the forecast decision, was to focus on issues related to the reasonableness of Edison's operations.

The ALJ ruling also indicated that the Commission would consider, following comments by the parties, Edison's request for interim relief by its June 1, 1988, revision date. Edison had argued, among other things, that due to several issues new to the ECAC, the delay in a decision by its revision date would be detrimental to Edison. Specifically, Edison proposed that interim relief involve either adoption of Edison's proposed AER or its suspension on an interim basis. It was Edison's opinion that such relief would mitigate the risks to ratepayers and shareholders from either understatement or overstatement of AER revenues during periods of changing energy prices.

On May 25, 1988, the Commission issued Decision (D.) 88-05-074 in this proceeding. By that decision, Edison was authorized to increase, on an interim basis, its Energy Cost Adjustment Clause revenue requirement by $200 million. This change was to result in a 3.7% system average percentage increase over present rates to all customer classes, except streetlighting for

which a 1.9% increase was authorized. Prior to the decision being issued, the Commission's Division of Ratepayer Advocates (DRA) had completed its forecast evaluation report recommending a revenue increase for Edison of $382.5 million.

D.88-05-074 also provided for the temporary suspension of Edison's Annual Energy Rate (AER) procedure. By D.88-07-066, issued July 22, 1988, D.88-05-074 was modified to provide greater specificity as to how the temporary AER suspension adopted in D.88-05-074 was to be implemented in rates.

Ten days of hearings in the forecast phase of this proceeding were held between May 23 and June 6, 1988, in San Francisco, California. This matter was submitted upon the filing of concurrent opening briefs on June 24, 1988, and concurrent reply briefs on July 1, 1988. The parties filing briefs in this proceeding included Edison, DRA, the California Cogeneration Council and the Cogenerators of Southern California (CCC/CSC), the Federal Executive Agencies (FEA), the California Manufacturers Association (CMA), the California Large Energy Consumers Association (CLECA), the Industrial Users (IU), the California City-County Street Light Association (CAL-SLA), and Toward Utility Rate Normalization (TURN).

Following the close of hearings, but before the receipt of briefs, several parties submitted late-filed exhibits indicating their proposed revenue allocations based on the most recent revenue requirements updates. Additionally, at the ALJ's direction, the Division of Ratepayer Advocates (DRA), on June 22, 1988, mailed a set of updated tables reflecting DRA's current recommendations on the Incremental Energy Rate (IER), revenue requirements, and revenue allocation.

As stated previously, Edison's final proposed annual revenue increase as of the submission of the forecast phase was $456 million. The components of this rate increase request, without consideration of the interim rate relief authorized in

D.88-05-074, included the following: an increase of $454 million for the Energy Cost Adjustment Billing Factors (ECABF), an increase of $44 million for Edison's AER, and a decrease of $42 million for the Electric Revenue Adjustment Billing Factor (ERABF).

The updated tables provided by DRA on June 22, 1988, have been included in the record as late-filed Exhibit 77. According to this document, DRA's final recommended revenue increase was $384 million. The components of this increase included an increase of $389 million in ECAC, an increase of $37 million in the AER, and a decrease of $42 million in ERAM.

In the ALJ's proposed decision issued in this proceeding on August 12, 1988, a procedure was adopted for developing a final revenue requirement and Incremental Energy Rate (IER) during the comment period following the issuance of that decision. The procedure which was followed is explained in full in this order.

Briefly, however, the procedure required DRA to "re-run" the ELFIN computer model to produce a final revenue requirement based on the forecasts and input assumptions adopted in the ALJ's proposed decision. Similarly, the parties who presented IER results during hearings were given the opportunity to "re-run" the ELFIN model based on the adopted input assumptions and modelling conventions and submit their final IER recommendations in their comments. These final revenue requirement and IER recommendations have been included as late-filed exhibits in this record.

On September 1, 1988, comments on the ALJ's proposed decision were filed by Edison, DRA, the CCC/CSC, and IU. These comments have been reviewed and carefully considered by the Commission. Any changes required by the comments have been incorporated in this final decision.

Based on its recalculated revenue requirement and IER presented in its comments, DRA proposed a $388 million increase in ECAC/AER/ERAM revenue requirement. The components of this increase

included an increase of $393 million in ECAC, an increase of $37 million in the AER, and a decrease of $42 million decrease in ERAM.

DRA also proposed an annual IER of 9,763 Btu/kWh, to which CCC/CSC concurred given the adopted assumptions. Edison included a final IER recommendation of 9,759 Btu/kWh.

The revenue requirement and IERs proposed by the parties in their comments were based on the consistent application of an ERI value of 0.43 for all months, to which the parties had stipulated. The proposed ALJ decision had adopted this stipulation, but included language suggesting that the ERI be increased to 1.0 for two months of the year. This language has been deleted in this order, and we find that the parties correctly applied the ERI value of 0.43 for all months of the forecast period.

In addition to the comments, on August 31, 1988, Edison filed a "Petition to Set Aside Submission and Reopen Hearings for the Forecast Phase." This petition is considered below.

C. Edison's Petition to Set Aside Submission

On August 31, 1988, Edison filed a petition to set aside submission of this proceeding and reopen hearings in the forecast phase. Edison's basis for this request is that "material, unforeseen events have occurred subsequent to the close of hearings which will significantly increase Edison's fuel and purchased power expense for the Forecast Period above that which Edison or [DRA] had forecast at the close of hearings on June 6, 1988." (Edison Petition, at p. 1 - 2.)

Edison includes in these events the following: (1) gas curtailment by Southern California Gas Company (SoCal) which began on August 16, 1988; (2) an increase in the priority of gas service to SoCal's Enhanced Oil Recovery customers over its Utility Electric Generation (UEG) customers on August 10, 1988; (3) the Federal Energy Regulatory Commission's implementation of an increase in El Paso Natural Gas Company's gas transportation rate

on July 1, 1988; (4) a change in Edison's ECAC balancing account from a $90 million overcollection on June 1, 1988, to a $2 million overcollection on August 1, 1988, and (5) the Commission's issuance of I.88-08-052 on August 25, 1988, which included an emergency order authorizing waiver of certain curtailment tariffs. On this last point, Edison acknowledges that this order was intended to increase gas availability to Los Angeles basin UEG customers prior to November 1, 1988. Edison states, however, that the additional gas and purchased power may be priced at or in excess of Edison's cost of oil generation.

In response to these circumstances, Edison requests that the following relief be granted: (1) the setting aside of submission of this proceeding and the holding of further hearings to hear evidence on these changed circumstances; (2) prior to a decision based upon the reopened record, the authorization to increase the ECAC revenue requirement by $88 million to reflect the August 1, 1988 balance in the ECAC balancing account; and (3) the continuation of the suspension of Edison's AER until a decision on the reopened record is issued. The revenue impact of these changes would be to increase DRA's final proposed ECAC revenue requirement from $388 million to $476 million, $20 million above Edison's final request in this proceeding of $456 million. DRA and CCC/CSC oppose Edison's petition.

While we share Edison's concerns with the changes in gas availability which have occurred since the issuance of the ALJ proposed decision, we are not persuaded to set aside the submission of this proceeding and reopen hearings. The purpose of the ECAC proceeding is to provide an opportunity for a utility to reflect in its rates forecasted changes in its fuel and purchase power expenses on an annual basis outside of the three-year rate case cycle. To effectively administer this annual rate change, a forecast period has been established for each utility which is

intended to be the focus of the ECAC proceeding and to provide a timely resolution of each ECAC application.

It is obviously impossible to forecast "unforeseen" circumstances occurring after submission of any ECAC which might alter the forecasts presented during the scheduled hearings. Because of this situation, the Commission, as in this case, has permitted updating of forecasts up to the point of submission. Further, ECAC expenses are recorded in a balancing account which can be reflected in the following forecast period. Additionally, it is possible that short-term fluctuations in fuel availability or price can balance out over the entire forecast period.

Under these circumstances, we find that to reopen the record in this case would defeat the purpose of the ECAC proceeding. Edison has had a full and fair opportunity to present its testimony on the current forecast period and will have the opportunity to file its next ECAC application early next year.

We also find that the Commission has already attempted to address the gas supply concerns expressed by Edison in the emergency order issued on August 25, 1988, in I.88-08-052. In that order, we stated that SoCal had "represented to the Commission that in order to attempt to meet its storage targets for the November 1 commencement of the winter heating season, SoCal has curtailed utility electric generation (UEG) service on non-episode days". (I.88-08-052, at p. 2.) In order to prevent the necessity of burning oil in the Los Angeles basin through November 1, the Commission by its order authorized the utilities to take several steps designed to alleviate this situation. In addition, the Commission scheduled expedited hearings to consider further any modifications or refinements to these emergency measures.

In the August 25 order, we concluded that the adopted emergency program "should ensure that Edison and the municipal electric utilities will receive substantial additional supplies of gas between now and November 1, 1988." (I.88-08-052, at p. 12.)

In keeping with SoCal's estimate of meeting its winter storage targets by November 1, the order directs that each of the adopted emergency measures will remain in effect until November 1, 1988. The order is to terminate on that date unless modified by the Commission by subsequent order. (Id., Ordering Paragraph 6.)

While we do not find it reasonable to reopen hearings in this proceeding, we do find that the existence of the gas supply shortage identified in our emergency order suggests that additional relief for Edison is appropriate in the context of this decision. We believe, however, that this relief should be limited to the identified period of the "emergency" -- from the present to November 1 -- and should relate to the economic risk to which Edison is actually exposed in the event that forecasted expenses do not match reality. That risk takes the form of the reinstitution of Edison's AER.

The AER is a fixed rate, a percentage of the ECAC, which is not subject to balancing account treatment and which makes a portion of fuel and purchased power costs recoverable on a fixed forecast basis. During periods of fluctuating fuel prices, Edison's AER has been suspended, but was recently reinstated at the 10% level in Edison's 1987 ECAC. In D.87-11-013 in that proceeding, we concluded that, given the then existing stability in fuel prices, reinstatement of the AER was appropriate to "provide an incentive to the utility's management to reduce its fuel and purchased power expenses and to have a direct stake in its fuel management decisions." (D.87-11-013, at p. 11.)

Current circumstances affecting Edison's gas supply, however, reflect a situation over which Edison's management may have little control. We therefore find it reasonable to continue the suspension of Edison's AER until November 1 when SoCal predicts that it will have met its target gas storage level for the winter period.

We remain committed, however, to the reinstatement of the AER. Its suspension, both in the case of the interim decision and the present order, have been dictated by certain specific circumstances. In the case of our interim order, the suspension was required due, among other things, to delays in this proceeding caused by the addition of issues new to this ECAC and to the significant rate increase requested by Edison. The need for any further suspension of the AER should therefore be determined only when and if circumstances warranting its suspension actually exist.

Finally, we address Edison's request for the recorded June 1 through August 1 balances in the ECAC balancing account to be reflected in this decision. Our goal, as we have previously stated, is to base this decision on the forecasts presented during the hearings in this proceeding. Edison is now asking us to take notice and include an $88 million increase based on recorded information in two months of the forecast period. We decline to take this step. The addition of the $88 million would have the impact of not only increasing by 22% Edison's ECAC revenue requirement derived from the adopted forecasts in this proceeding, but also causing the final authorized revenue to exceed the level requested by Edison. We believe that substantial and adequate rate relief is afforded by this decision without the need for any further increase.

D. <u>ECAC Issues</u>

The focus and purpose of an ECAC proceeding has traditionally been to enable a utility's rates to reflect changes in its fuel and purchase power expenses on an annual basis outside of the three-year general rate case cycle. Edison's current ECAC continues the consideration of these "traditional" ECAC issues. In addition, however, this proceeding also marks the beginning of the regular annual updating in ECAC of key components in the calculation of prices paid for power sold to the utility by qualifying facilities (QFs).

These QF issues have been added to the ECAC as a result of D.88-03-026 in the generic standard offer proceeding, A.82-04-044, et al. In that decision, the Commission concluded that annual updating of variable QF payments should take place in a utility's ECAC proceeding. The Commission reasoned in D.88-03-026 that it was preferable "not to create a unique proceeding for QFs [for this purpose], but rather to make optimal use of ECAC by setting QF prices at the same time (and from the same assumptions) that we adjust utility rates." (D.88-03-026, at p. 3.)

Variable QF prices are actually the sum of two basic components: a variable payment for capacity and a variable payment for energy. Critical to the determination of these payments are the utility's Energy Reliability Index (ERI) and Incremental Energy Rate (IER). The ERI is used to adjust the value of a combustion turbine on which the QF's capacity payment is based. The IER, which reflects the utility's incremental efficiency in converting heat energy to electricity, is multiplied by the utility's incremental fuel cost to produce the price paid by the utility for the QF's energy output.

ERI and IER values are generally derived from the results produced by production cost models. These models are designed to simulate the manner in which utility resources meet system loads. This simulation is driven by the resource and load assumptions which are chosen as inputs into the model.

Edison's IER and ERI were most recently determined in its test year 1988 general rate case (A.86-12-047). In anticipation of the annual updating of these QF payment components, the Commission in D.87-12-066 in that proceeding adopted a procedure to be followed in developing and presenting testimony related to the IER and ERI. The purpose of this procedure was to ensure the full exchange and understanding of models and data used to develop the IER and ERI.

Specifically, the Commission required that all parties to future Edison ECAC and general rate case proceedings use the ELFIN production cost model in developing a "base case" run. (D.87-12-066, at p. 203.) The Commission reasoned that use of the same model "to present a base case will aid the Commission, as a starting point, in determining whether model, assumption, or methodological differences are causing the different results." (Id.) Each party, however, was also given the opportunity to present additional testimony using its model of choice. (Id.)

Additionally, the Commission directed that "a workshop be held no later than one week following Edison's ECAC filing to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which Edison used to calculate its IER." (D.87-12-066, at p. 205.) The workshop was also to serve as a forum for the parties to agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission Advisory and Compliance Division (CACD) was to appoint an arbiter for the workshop to resolve any issues related to the development of a common data set upon which agreement could not be reached.

In compliance with these directives, on January 25, 1988, the CACD noticed a workshop to develop common data set assumptions for ELFIN computer model runs to be used in this proceeding. The workshops were held on February 17 and 18 and March 3, 1988, with Linda Gustafson of the CACD serving as arbiter. On March 16, 1988, the common data set for a base case ELFIN run to which the workshop participants had agreed was served on all parties by the CACD.

The issues litigated in this phase of Edison's ECAC therefore have included not only Edison's revenue requirement for the ECAC forecast period, but also the development of the IER and ERI used in determining variable QF payments. As directed by

D.87-12-066 and D.88-04-026 in Edison's most recent general rate case, revenue allocation, but not rate design, was also considered in this proceeding.

In reviewing these issues, we will first examine the method for determining revenue requirement and IERs. In this regard, Edison and DRA did not agree on the need for a common methodology to determine both revenue requirement and IERs.

The need to "re-run" programs or computer models during the comment period following the issuance of the ALJ's proposed decision based on our adopted forecast expenses and assumptions is also examined. This discussion is followed by an examination of the individual assumptions and ratemaking approaches at issue which directly affect not only the revenue requirement forecast for Edison, but, with respect to certain assumptions, variable QF payments as well. We then examine the calculation of variable QF payments, including the recommended IERs and the stipulated ERI. The final section of this decision addresses the issue of revenue allocation.

Before proceeding with our discussion, we wish to remark, as DRA has done in its brief, on the need for updates in an ECAC proceeding. There appeared to be some concern during the hearings regarding the updating of Edison's and DRA's final revenue requirement and IER recommendations. As stated by DRA in its brief, however, every change in an expense number related to expected generation or resource availability requires the development of a new revenue requirement, a new IER, and new revenue allocation recommendations.

We concur with DRA's statements. Our effort in an ECAC proceeding is to reflect the most up-to-date data for any adopted forecast expense or IER. This effort, which protects the utility, its ratepayers, and QFs alike, becomes more critical when the requested relief will result in a significant rate increase, as is the case in this proceeding. As DRA points out, although both

Edison's and DRA's final recommendations were far below Edison's original request of $628 million, ratepayers still faced the possibility of a system average rate increase of between 7.1% (based on DRA's $384 million) and 8.4% (based on Edison's $456 million). In authorizing such an increase, the Commission should be confident that the required revenue is based on the most recent data and reliable forecasting expertise presented prior to submission of the case. We therefore find that in this proceeding it was reasonable for Edison and DRA to update their recommendations.

E. Method for Determining Edison's Revenue Requirements and IER

The forecast used to develop Edison's revenue requirement is derived from the estimated production and expense levels related to hydro, coal, nuclear, purchased power, alternative/renewable power, and oil and gas resources. The forecasts of energy production and availability impact the determination of Edison's generating efficiency at the margin as measured by the IER.

In this proceeding Edison used its Fuel and Purchase Power (FPP) spreadsheet computer model to determine its forecast energy mix and expense for purposes of determining its revenue requirement and the ELFIN production cost computer model for determining its IER. In contrast to Edison, DRA used the ELFIN model to determine both its forecast of generation and expense, as well as its recommended IER. ELFIN was also chosen by the CCC/CSC to provide their recommended IER. No party relied on a production cost computer model other than ELFIN to develop its recommended IER.

In this section, we will examine the arguments of Edison and DRA regarding the merits or need to use ELFIN to determine Edison's forecasted generation and expense, as well as its IER. Both Edison and DRA requested that if the Commission were to adopt only certain specific components of either forecast, DRA and Edison be permitted to rerun either the FPP or ELFIN model during the

comment period following the issuance of the ALJ's proposed decision to derive a revenue requirement.

1. Parties Positions

As stated previously, in this proceeding Edison used its FPP spreadsheet program to determine resource mix and average heat rates, and ELFIN to determine its IER used in QF energy payments. According to Edison, the FPP spreadsheet program uses a deterministic energy balance algorithm to calculate energy production for each resource or resource type. Edison states that the deterministic equations are based upon historical performance, forecast gas prices, hydro conditions, and known contractual obligations among other input. Once the resource mix and average heat rate for gas-fired units have been determined, the total revenue requirement may be calculated.

Edison believes that its FPP spreadsheet program is preferable to ELFIN due to its relative ease of use, ability to verify study results, historical accuracy, and stability of output. It was Edison's testimony that FPP results could be generated in a maximum of two days. Edison also notes that the Commission has relied on the FPP spreadsheet in determining Edison's revenue requirement in past Edison ECAC proceedings.

In contrast, Edison finds the following shortcomings in using ELFIN to derive its revenue requirement:

1. The time required to produce ELFIN results. Edison states that ELFIN results, produced only after multiple iterations, reasonableness reviews, and extensive post-processing, are yielded only after several weeks.

2. ELFIN's need for modeler's judgment. Edison states that the reasonableness checks for each ELFIN iteration are largely dependent upon the modeler's judgment of how well the model mimics expected system operation.

3. ELFIN's inherent "lumpiness". Edison defines this phrase as referring to small changes in the input assumptions causing large and unpredictable changes in ELFIN results.

4. The propriety of using ELFIN in forecasting revenue requirement. According to Edison, for forecasts of one year or less production cost models such as PROMOD or ELFIN are no more appropriate or accurate than any other method. Edison also states that there is no requirement that ELFIN be used to determine both revenue requirement and IERs and that a model suitable for one purpose may not be suitable for another.

Edison notes that its use of ELFIN for developing IERs also does not indicate its acceptance of that model, but rather its need to respond in a timely fashion to the dictates of D.87-12-066.

Edison therefore urges the Commission to continue its reliance on Edison's FPP spreadsheet program for forecasting revenue requirement. In its brief, however, Edison does recognize the possibility of the Commission adopting ELFIN for forecasting revenue requirement, but relying upon input assumptions different from those used by DRA in its ELFIN run. Edison asks that under those circumstances Edison be given the opportunity to submit its own results of the ELFIN model or the FPP spreadsheet program or both based on the final adopted input assumptions. Edison believes that this process would be particularly useful in verifying ELFIN results.

It is DRA's opinion that for this ECAC the Commission should rely on ELFIN for both revenue requirements and IERs. DRA states that it is the only party to this proceeding that has presented a single, consistent set of integrated assumptions and conclusions that can be adopted by the Commission and used to determine both Edison's revenue requirement and IER in this proceeding.

In support of its position, DRA states that ECAC revenue requirements flow from a forecast of how the utility system will operate in the coming year. According to DRA, the most appropriate method to forecast system operation is a production cost model, such as ELFIN, that simulates system operation. DRA states that this simulation of system operation, not possible on a spreadsheet program such as Edison's FPP, reflects the dispatch of resources and optimization of system operation based on resources and load conditions expected during the forecast period.

DRA acknowledges that ELFIN may not be a perfect model of system operation, but asserts that it is a significant step beyond a spreadsheet program. According to DRA, at this time, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Sierra Pacific all use some type of production cost model to forecast their resource mix and revenue requirements.

DRA also argues that consistency requires the use of ELFIN to produce Edison's revenue requirement when it has been used exclusively by the parties to produce IER recommendations. In DRA's view, the Commission should not permit the use of different forecast resource mixes for different purposes in the same proceeding. DRA states that such an approach reduces the benefits of uniformity and efficiency that should result from using a combined proceeding to determine both revenue requirements and IERs.

In response to Edison's criticism of ELFIN, DRA cites Edison's own testimony indicating that ELFIN had produced reasonable results in Edison's in-house attempts to develop a revenue requirement based on ELFIN. DRA further notes that a comparison of FPP and ELFIN results showed a maximum difference of 4% between those results.

DRA believes that Edison's main concern is its desire to verify the results of ELFIN if adopted. DRA believes that this concern can be adequately addressed in comments following the issuance of the ALJ's proposed decision. DRA suggests that comments be limited in scope to noting errors in entering the input assumptions or offering corrections to outputs that are demonstrably erroneous given the adopted input assumptions.

2. Discussion

In our effort to determine a meaningful and efficient way in which to update variable QF payments, we chose in D.88-03-026 to undertake those updates in the utilities' ECAC proceedings. In making this choice, we specifically rejected the use of an annual proceeding separate from ECAC as it "would not be orderly or administrable, nor would it properly integrate QF pricing within the regulatory framework." In particular, we found as follows:

> "If we were to require the use of ECAC assumptions in a subsequent single proceeding for QF pricing, QFs would appear in ECACs to litigate those assumptions, and the subsequent proceeding would have little point. If we were to update those assumptions in the later proceedings, we would have essentially a new ECAC proceeding, just for QFs, but involving all three major electric utilities." (D.88-03-026, at p. 3.)

We concluded that the "solution to this problem is not to create a unique proceeding for QFs, but rather to make optimal use of ECAC by setting QF prices at the same time (and from the same assumptions) that we adjust utility rates." (D.88-03-026, at p. 3.) For similar reasons, we rejected PG&E's proposed quarterly adjustment of IERs based on a narrower review of input assumptions than that performed in ECAC. In this regard, we found that "selective updating, even where the assumptions to be updated are specified in advance, [seemed] susceptible to 'gaming' by the parties." (Id., at p. 4.) We also questioned whether the selected

assumptions could fairly or reasonably be changed without re-examination of all other inputs.

This decision makes clear our intent to provide a consistent approach to the development of both a utility's rates and QF prices. A review of QF standard offer decisions reflects that this goal has long been embraced by the Commission to ensure accurate prices to QFs as well as ratepayer indifference to the source of a utility's power.

Edison is correct in stating that the propriety of using a production cost model or ELFIN in particular for developing IERs may not necessarily extend to forecasting revenue requirement. Edison is also correct in stating that its FPP program was used to develop its revenue requirement in its 1987 ECAC proceeding.

Reliance on these factors by Edison to support its continued use of the FPP spreadsheet, however, ignores changes in this Commission's and other utilities' approaches to ECAC proceedings. Specifically, Edison's most recent ECAC did not consider the updating of the utility's IER or ERI used in variable QF payments. Further, as DRA notes, both PG&E and SDG&E have chosen to use a production cost model, namely PROMOD, in forecasting resource mix and revenue requirements in their most recent ECAC proceedings.

In PG&E's current ECAC (A.88-04-057), PG&E states in Exhibit 1 at page 3-3 that "[f]orecast area loads as well as forecasts of the various resource availabilities and prices are input to PROMOD along with data pertaining to electric system reserve and reliability requirements, operating constraints, and contractual requirements." PG&E's approach seems to recognize that the simulation of system operation provided by a production cost model is as necessary to determining IERs as it is to developing the resource mix in forecasting revenue requirement.

Embracing the computer age should also not be a selective process. While Edison may have had questions about ELFIN, the requirement for Edison to use ELFIN in this proceeding was limited to using that model to produce a base case run for the IER calculation. Edison was free, however, to rely on a different, preferred computer model on which to base its revenue requirement or IER recommendations. We are aware that Edison owns PROMOD and has consistently relied on its results in other rate and standard offer proceedings, including its most recent general rate case.

It should be clear to Edison, following our issuance of D.87-12-066 and D.88-03-026, that it is our goal to ensure that updates and forecasts of a utility's resource mix and expense, IERs, and ERIs are made on a consistent and uniform basis. Such consistency not only "integrate[s] QF pricing within the regulatory framework", but assures that we are "setting QF prices at the same time (and <u>from the same assumptions</u>) that we adjust utility rates." (D.88-03-026, at p. 3, emphasis added.)

As we stated in D.88-03-026, this approach also alleviates any possible "gaming" by the parties. In this regard, we note that the times of traditional ECAC participation being limited to the utility and DRA are behind the Commission. Instead, we face an era when ECAC issues have extended to include not only QFs, but also interested parties concerned with rate design and revenue allocation.

In our review of the arguments presented by Edison regarding ELFIN, we find Edison's misgivings center for the most part on the efficiency of using ELFIN. We do not find in those arguments, or for that matter Edison's discussion of the specific assumptions, any evidence that ELFIN produces unreasonable forecast results or results substantially at odds with the FPP spreadsheet program. Further, the use of the production cost model to forecast both revenue requirements and the components of variable QF payments best achieves our regulatory goal of consistency in the

development of utility rates and QF prices, reflects the growing reliance on computer modeling in ratemaking, and ensures consistent results. The fact that ELFIN is the sole model upon which we can rely is merely a circumstance of this particular ECAC, and one which the parties need not repeat in Edison's next ECAC.

For these reasons, we will adopt DRA's recommendation to use ELFIN to develop both Edison's revenue requirement and IERs. With respect to updating the revenue requirement during the comment period following the issuance of the ALJ's proposed decision, a procedure discussed below, we concur with the ALJ's proposed decision that it was not necessary for Edison to "re-run" its FPP spreadsheet or develop a new ELFIN run.

Specifically, the ALJ had noted that Edison's and DRA's most significant disagreement on forecast assumptions centered on the forecasted gas price. Both parties agreed that this difference was in turn largely responsible for differences in their other forecast recommendations.

In this regard, we concur with the ALJ's adoption of DRA's forecasted gas price and, in turn, the ALJ's adoption of most of DRA's other revenue requirement recommendations. Under these circumstances, it was necessary only for DRA, and not Edison, to "re-run" the ELFIN model in the comment period and present its results as a late-filed exhibit. Even if DRA's recommendations had not been adopted, we still do not believe that it would have been appropriate for Edison to "run" ELFIN for the first time or present its FPP spreadsheet again during the comment period to produce a revenue requirement. If we permitted Edison to take such a step, we would be allowing Edison to present a revenue requirement methodology which either it had never presented during hearings (ELFIN) or the Commission had rejected (FPP spreadsheet).

In contrast, DRA has already presented, and had subject to cross-examination, its approach to developing Edison's revenue requirement. Though Edison expressed misgivings about ELFIN

itself, Edison presented no significant challenges or objections to the way in which DRA ran the model or applied its judgment to any post-processing required to obtain reasonable results.

In the case of the IER, we note that the ALJ did not uniformly adopt the assumptions of any single party. This circumstance therefore necessitated the parties' "re-running" ELFIN during the comment period following the issuance of the ALJ's proposed decision and presenting their final recommendations as late-filed exhibits. The parties making ELFIN runs during the comment period to develop final revenue requirement (DRA) or IER (Edison, DRA, and CCC/CSC) recommendations were directed in the ALJ's proposed decision to serve each other with all supporting work papers at the same time their comments were filed.

The ALJ's proposed decision expressed the hope that, with the use of the same model and adopted assumptions, the IER results produced by the parties would not vary greatly. The ALJ also believed that the adopted procedure for considering these results, necessitated by time constraints in this proceeding, was appropriate since all parties had used the same model and would now be using the same assumptions. Additionally, each party would have had an equal opportunity through many days of workshops and hearing to discuss and cross-examine each party's use of ELFIN.

In fact, the ALJ's views have proved to be correct. The final recommended IERs of the parties, based upon assumptions which we also endorse, vary little from each other. Edison proposes an IER of 9,759 Btu/kWh, and DRA and CCC/CSC support an IER of 9,763 Btu/kWh.

We note that consideration of final revenue requirement and IER recommendations in the comment period following the issuance of the ALJ's proposed decision may not ultimately be the preferred method of litigating ECAC assumptions and results. As DRA has stated in its brief, however, this forecast period is in effect for only one year and, like any forecast, is marked by some

uncertainty. To meet legitimate regulatory goals in a timely fashion, we believe that it was inappropriate to lengthen this ECAC forecast phase unnecessarily.

Specifically, we note that meeting this mid-September issuance date for the final decision in the forecast phase was critical to assure that the IER and ERI adopted in this decision would be reflected in the QF price filings to be made by the utilities on November 1, 1988. (D.88-03-026, at p. 6.) Failure to meet this deadline would have meant that QF prices adopted for this forecast period would not have gone into effect until February, 1989, a period just short of the commencement of Edison's next forecast period. Such a result defeats the purpose of the updating contemplated by D.88-03-026.

It is our hope that the parties will have sufficiently adjusted to new ECAC issues and procedures this year to result in greater efficiency in completing the 1989 ECAC. This effort should be aided by changes to ECAC time schedules being reviewed by the Commission in Rulemaking (R.) 87-11-012.

F. Forecast of Energy Expense and Resource Mix

In this section we will examine the parties' recommended forecasts of energy expense and resource mix. Certain of these forecasts impact Edison's revenue requirement only, while others impact both revenue requirement and IER recommendations. The majority of the issues were addressed only by Edison and DRA with the CCC/CSC focusing on those issues, including gas dispatch price and resource mix, directly related to the determination of Edison's IER.

In reviewing assumptions related to the development of Edison's IER, we wish to note the value of the IER workshops which preceded hearings in this proceeding. These workshops enabled parties to achieve a timely exchange of data and to clearly identify those issues upon which agreement could not be reached. Such a result is not a minor, but a significant achievement,

especially in a proceeding which must be heard in a limited time. We appreciate the efforts of all of the parties in participating in this workshop and encourage the continued use of this forum to enhance the efficiency and value of the ECAC hearing process.

- The following table excerpted from DRA's late-filed Exhibit 77, submitted on June 22, 1988, provides a comparison of Edison's and DRA's forecast ECAC revenue requirements absent consideration of the interim rate relief granted on May 25, 1988. This table reflects differences between Edison and DRA on the following issues: (1) natural gas generation and expense, (2) oil generation and expense, (3) purchased power generation and expense, (4) coal generation and expense, (5) fuel oil inventory carrying costs, and (6) franchise fees and uncollectible accounts expense and resale accounts allocation.

Comparison of DRA and SCE ECAC Revenue Requirement Prior to Interim Rate Relief
Update Based on April 1, 1988 Snow Survey; Revised June 1988
($ Thousands)

Ln	Item Description	DRA 5/ (a)	SCE 6/ (b)	SCE - DRA (c) = (b)-(a)	Percent Diff. (c)/(a)
1	Oil	324,837	348,143	323,306	93.8%
2	Gas	613,251	628,991	15,740	2.6%
3	Coal	108,720	108,968	248	0.2%
4	Nuclear	165,052	165,052	0	0.0%
5	Purchased Power	1,267,557	1,300,728	33,171	2.6%
6	Less: Off-System-Sales	19,067	20,996	1,929	10.1%
7	Subtotal	2,160,350	2,230,886	70,536	3.3%
8	Less: Resale	12,523	12,932	409	3.3%
9	Total Subject to ECA&F	2,147,827	2,217,954	70,127	3.3%
10	Less: 10 percent AER	214,783	221,795	7,012	3.3%
11	Subtotal Energy Expenses	1,933,044	1,996,159	63,115	3.3%
12	Plus: Fuel Oil Inventory	5,626	6,938	1,312	23.3%
13	Carrying Costs				
14	Coal Inv. C.C.	686	649	(37)	-5.4%
15	Nuclear Fuel C.C.	25,229	25,384	155	0.6%
16	Subtotal	1,964,585	2,029,130	64,545	3.3%
17	Plus: Fr. Fees & Uncoll.	18,722	19,338	615	3.3%
18	ECAC Fuel & P.P. Costs	1,983,308	2,048,468	65,160	3.3%
19	Est ECAC Bal. at 6/1/88 1/	(89,491)	(89,491)	0	0.0%
20	Plus: Fr. Fees & Uncoll.	(853)	(853)	0	0.0%
21	Subtotal	1,892,964	1,958,124	65,160	3.4%
22	Plus: LSFO Write-down	54,862	54,862	0	0.0%
23	Dist. Write-down	4,572	4,572	0	0.0%
24	Chevron Settle.	204,427	204,427	0	0.0%
25	Uran. Contr. Term.	77,722	77,722	0	0.0%
26	Total ECAC Rev. Req.	2,234,547	2,299,707	65,160	2.9%
27	Present ECAC Revenue 2/	1,845,000	1,845,000	0	0.0%
28	Change in ECAC Rev. Req.	389,547	454,707	65,160	16.7%
29	Sales (gWh)	65,312	65,312	0	0.0%
30	Pres. ECAC Rate (c/kWh) 3/	2.825	2.825	0.000	0.0%
31	Proposed Rate (c/kWh) 4/	3.421	3.521	0.100	2.9%
32	Rate Change (c/kWh)	0.596	0.696	0.100	16.7%

1/ From Exhibit 39.
2/ From Exhibit 52.
3/ Line 27 divided by line 28.
4/ Line 26 divided by line 29.
5/ Reflects updated CA hydro and PNW forecast from Exh. 66, and 1RT pp.174-176.
6/ Reflects hydro and coal expense corrections shown in 1RT pp.27 and 5RT pp. 467-469. Related expense changes translated into rev. rqmts. based on a 6/8/88 data transmittal from SCE to DRA.

The parties did reach agreement on the (1) sales forecast, (2) Edison hydro generation, (3) nuclear generation and expense, and (4) the estimated ECAC and ERAM account balances. The following summarizes those areas of agreement:

1. Sales Forecast. DRA agrees with Edison's net off-system sales projection of 1,003 million kWh, as well as the forecast sales to customers of 65,312 gWh.

2. Edison Hydro Generation. DRA agrees with Edison's forecasted total hydro production of 3,327 gWh and the results of the April 1, 1988, snow survey.

3. Nuclear Generation and Expense. DRA and Edison agree on the forecasted nuclear generation and expense with the exception of a minor difference in energy production due to ELFIN dispatch. DRA concurs with Edison's request that, in order for such expenses to receive consistent ratemaking treatment, the uranium portion of nuclear fuel expenses be subject to the ECABF/AER percentage allocation.

   In addition, DRA and Edison agree that 25 basis points should be added to the appropriate interest rate for financing issuance costs in calculating in-core nuclear fuel inventory carrying costs. DRA has no objection to Edison financing its in-core nuclear fuel with a mixture of short-term and intermediate term debt. DRA agreed that if Edison issues intermediate term debt financing for nuclear fuel, the forecast should reflect the intermediate-term debt.

4. Estimated ECAC and ERAM Balancing Accounts. DRA agrees with Edison's estimated June 1, 1988, ECAC Balancing Account balance. DRA and Edison agree on the estimated June 1, 1988, ERAM Balancing Account balance and resultant ERAM revenue change for a June 1, 1988 Revision Date.

We find that the areas of agreement between Edison and DRA are reasonable and should be adopted. With respect to disputed issues, the difference between Edison's and DRA's revenue requirement recommendations is largely attributable to the difference in their gas price forecasts and the effect such forecasts have on the quantity and price of Edison's power purchases.

1. **Forecast of Fuel and Purchased Power Generation and Expense**

a. **Gas Generation Expense**

The forecast price of gas not only determines the cost of running many of Edison's own resources, but is also used in forecasting economy energy quantities and prices and in determining QF payments. The DRA forecast of gas generation is approximately $16 million less than that forecasted by Edison. This difference stems from differences in the parties' forecasts of the spot gas price, oil burn, and quantity of purchased power resulting from the parties' different forecast gas prices.

It is Edison's opinion that it effectively demonstrated that gas prices likely to occur during the forecast period are going to be higher than those forecast by DRA. According to Edison, its forecast was based on the following factors: (1) recent historical prices paid by Edison for spot gas prices, (2) the continuance of seasonal price trends in which winter prices are higher than summer prices, (3) the decrease in the national gas deliverability surplus, (4) the current gas production selling at prices below the cost to develop new gas reserves, and (5) the increased likelihood of winter gas curtailment to the Utility Electric Generation (UEG) market. Edison further states that its forecasted increase in the spot market price of natural gas represents only an increase of 6% in comparison with the most recent 12 months of experience.

According to Edison, its forecast reflects industry experts' opinions and present market conditions. This analysis includes a reasonable projection of an increased gas requirement by Edison due to dry hydro conditions and longer gas curtailments of the UEG market due to higher gas demand.

While not a part of the evidentiary record in this proceeding, Edison also requests that the Commission take official notice of a recent Federal Energy Regulatory Commission (FERC) filing by El Paso Natural Gas Company (El Paso). This filing requests significant increases in the transportation price for gas to the California/Arizona border. (Docket RP 88-44 (May 31, 1988).) Edison states that the new gas price, effective July 1, 1988, would cause the transportation rate and the price of spot gas to increase, on average, by 40 cents to 50 cents per million Btu.

With respect to the forecast spot market gas price, Edison notes that there is essentially no difference in Edison's and DRA's forecasts for the first six months of the forecast period. Edison urges recognition, however, of an increase in the spot market price for the December 1988 to May 1989 forecast period greater than that forecast by DRA. In support of its position, Edison points to the prolonged gas curtailment during December 1987 through February 1988. Edison believes that, based on its curtailment during three of the last four winters, seasonal curtailment is highly probable despite overall annual gas supply adequacy. For the spring period, Edison states that its May 1989 price represents only a conservative 20 cent per million Btu increase over the forecasted June 1988 price.

Edison objects to DRA's assertion that DRA's forecast is more reliable than Edison's forecast due to DRA's greater accuracy in predicting actual prices in Edison's prior ECAC. Edison states that the accuracy of one particular forecast is insufficient to prove that a methodology is reliable and reasonable. Edison

therefore asks that the reasonableness of its forecast in this proceeding be judged in the context of the regulatory and market circumstances that currently exist, not upon prior forecast accuracy.

As described by DRA, its forecast gas price was based on three components. These components included: (1) the UEG transportation and demand charges based on recent advice letter filings by Southern California Gas Company (SoCal) and PG&E in response to D.87-12-039, (2) commodity costs for gas supplies purchased from SoCal based on the estimated SoCal border price for gas, and (3) the P5 or bulk burn price based on DRA's estimated mix of SoCal Tier II volumes and Edison's independently obtained spot supplies.

In explaining its approach, DRA states that the Tier II price of gas is the key determinant of DRA's forecast of the dispatch price of gas. According to DRA, the dispatch price is used in making economic choices about what energy sources to utilize in system operation. DRA determined the dispatch gas price by weighting the price of expected spot gas purchases from SoCal Gas and the price of purchases from other sources during the forecast period. DRA asserts that Edison's recent spot gas purchasing history and the major changes that flow from the unbundling of the gas market support DRA's projection that Edison will purchase 60% of its spot gas from SoCal Gas and 40% from other sources. DRA priced this independently procured gas at 96% of the Tier II price. DRA states that this method of forecasting the dispatch price was not challenged by Edison in either its cross-examination of DRA's witness or in Edison's brief.

In further support of its showing, DRA states that testimony in this proceeding shows that the recorded average spot gas price for the 1987 ECAC period was $1.86. DRA's average forecast gas price for the 1988 ECAC period is $1.87, a level slightly higher than the previous forecast period. In contrast,

DRA notes that Edison's $2.04 annual average represents an approximate 9% increase over last year's recorded average.

Additionally, DRA states that its gas price forecast appropriately reflects seasonal variations, with prices approximately 20 cents higher in the winter time. DRA notes that its witness stated on cross-examination that if he were to alter his forecast to reflect current conditions, he would lower the June and July 1988 prices by 10 to 15 cents. This circumstance reflects, in DRA's view, that its forecast is actually somewhat conservative. DRA also notes that the actual spot gas prices in April and May of 1988 went below any of the 1987 ECAC forecasts for May 1988 and below the Summer 1988 forecast for the 1988 ECAC by both Edison and DRA.

In support of the accuracy of its forecast, DRA states that, in the first nine months of the last ECAC period, its witness's forecast was within $0.04/MMBtu of the weighted average ECAC price based on Edison's actual spot purchases. This forecast was also within $0.05/MMBtu of the weighted average ECAC price based on Edison's actual total gas purchases. In contrast, DRA states that Edison's forecast errors were nearly double DRA's. Based on these circumstances, DRA asserts that its methodology and recommendations have proven to be reliable and reasonable.

DRA objects to Edison's methodology for its selective use of its consultants' forecasts. DRA states that in forecasting oil prices, Edison used the arithmetic average of the forecasts of the three consulting firms which it retained. For its gas price forecast, however, DRA notes that Edison used the arithmetic average of only the two highest of the three forecasts produced by these firms. For its updated gas price forecast, DRA states that Edison's witness chose to rely on none of the retained firms, and chose instead to rely on the published reports of other experts.

DRA also argues that the evidence in this proceeding does not support Edison's claim of severe UEG gas curtailments during the winter. DRA believes that the circumstances leading to the lengthy gas curtailment during last winter, including an unusual cold spell, structural changes in the gas industry, and unusual storage problems on the SoCal Gas system, are unlikely to reoccur this winter. DRA further notes that its gas price forecast takes into account DRA's forecast 15-day curtailment period.

Finally, DRA rejects Edison's reliance on the recent El Paso filing with FERC. DRA believes that Edison jumps too quickly to the gloomy conclusion that the result of this filing will be to increase the price of spot gas by 40 to 50 cents per million Btu. Even assuming that FERC approves this prices increase, DRA states that its effect on Edison's gas prices is a matter of pure speculation. In practice, DRA states that El Paso may charge some, all, or none of that increased authorized transportation rate.

CCC/CSC supports DRA's modeling of the dispatch gas price. CCC/CSC states that Edison has offered no basis for rejecting DRA's forecast. Additionally, in CCC/CSC's opinion, Edison showed a systematic disregard of its own experts reflected finally in a forecast update which relied on none of those experts.

CCC/CSC also objects to Edison's reliance on the El Paso filing. CCC/CSC asserts that this filing has not been the subject of any meaningful review in this proceeding nor has yet to be adjudicated.

We find DRA's arguments in support of its gas price forecast to be persuasive. Inconsistencies in Edison's forecast approach, as well as an exaggerated response to seasonal curtailments, undermine the reliability of Edison's forecast. Further discussion of the parties' estimates of gas curtailment are included in the following section on oil generation expense.

Based on our review of the record, we find that DRA has examined all of the elements necessary to provide a reasonable gas

price forecast and in turn a reasonable level of gas generation expense. DRA has appropriately considered recorded data and made allowances for seasonal variations in gas prices. We also concur with DRA and the CCC/CSC that reliance on the El Paso filing is premature and that its impact on gas prices can not yet be quantified.

Finally, while DRA's accuracy in forecasting last year's gas price is alone not sufficient to adopt its current forecast, it does act as further support of the experience of the forecaster and the soundness of the methodology. We therefore find reasonable and adopt DRA's forecast of Edison's gas generation expense.

b. Oil Generation Expense

Edison's oil generation expense depends primarily on estimates of two factors: the quantity of oil expected to be consumed and the replacement cost of the oil. In this proceeding, Edison and DRA offer different forecasts of both these factors. Their estimates of the quantity of low sulfur fuel oil (LSFO) expected to be burned during the forecast period differs primarily as a result of different forecasted gas curtailment.

Edison estimates 1.58 million barrels of LSFO burn due to gas curtailment, while DRA estimates 390,000 barrels of burn. The price per barrel of LSFO is forecast at $20.05 per barrel by Edison and $18.23 per barrel by DRA. Based on these estimates, Edison forecasts a level of oil generation expense at $48.1 million while DRA recommends an expense level of $24.8 million.

Edison states that its estimate of LSFO burn is based upon Edison's most recent historical experience and Edison's judgment as to the potential effect recent market and regulatory changes will have on the amount of gas available to Edison. Edison believes that its 1.5 million barrel estimate is reasonable following a winter where 1.2 million barrels of LSFO were burned. Edison notes that last winter's LSFO burn would have been greater

had Edison not been able to purchase an unanticipated amount of firm electric energy.

With respect to LSFO prices, Edison states that it based its forecast on a consensus forecast of low sulfur waxy residue (LSWR) prices which was used as a proxy for the price of LSFO to Edison. Edison states that it obtained LSWR price forecasts from three industry experts, each with a knowledge of the market forces affecting low sulfur oil. Each consultant's LSWR price forecast was then reviewed for reasonableness by Edison and was weighted equally in Edison's consensus forecast.

Edison believes that DRA erred in its forecast by multiplying the 1984-86 gas curtailment data by the 1987-88 oil burn rate. According to Edison, this approach mismatches the burn rate and curtailment days from different time periods and should be rejected.

DRA states that the issues of forecasted oil burn and gas curtailment are intertwined. In making its recommendation DRA states that it accepted all of Edison's LSFO oil burn figures except the amount of oil to be burned during November, December, and January. In those months, Edison predicts 1.58 million barrels will be burned, while DRA forecasts that only 470,200 barrels of LSFO will be burned.

DRA states that its estimate is based on two factors: (1) a forecast of 15 days of gas curtailment in the forecast period, which is multiplied by (2) a forecast daily oil burn rate of 26,000 barrels. DRA's forecast of 15 days of gas curtailment is based on the 1987 California Gas Report as well as information supplied by SoCal Gas, Edison's chief supplier. As noted in the previous section on gas generation expense, DRA believes that, despite the severe curtailment last winter, the circumstances causing that curtailment (i.e., unusual cold snap coupled with SoCal's extraordinary storage problems) are unlikely to be

repeated. DRA also notes that, based on a 5-year average including last winter's curtailment, only an 18 day curtailment would result.

DRA notes that Edison did not provide its estimated days of curtailment. DRA found, however, that, in applying methodology to Edison's oil burn forecast, Edison was predicting about 59 days of curtailment. DRA asserts that this period is well beyond even the unusual six weeks of curtailment Edison experienced last winter.

DRA disputes Edison's assertion that it is inappropriate to pair a curtailment period derived from historical data with a burn rate derived from current data. In DRA's opinion, the best forecast of curtailment does not rely on a single curtailment period, but includes some historical average adjusted if necessary to reflect current conditions. DRA states that it therefore appropriately relied on the burn rate that most closely matched the generation units that were likely to be generating next year. Following this approach, the appropriate burn rate was the most recent burn rate.

According to its testimony, DRA made its own independent forecast of oil prices for the forecast period. DRA's forecast of fuel oil price is based on its estimate of LSWR prices and marine transportation rates. DRA believes that its LSWR price forecast compares favorably with the range of prices forecast by the federal government.

In reviewing Edison's and DRA's forecasts, we note that it is our intention to maintain consistency in the forecasts of both gas and oil expenses with respect to all common components. In this case, the issue of the estimated period of gas curtailment impacts both gas and oil generation expenses. As we stated earlier, we find that DRA has made reasonable assumptions concerning the level of curtailment which Edison can anticipate this winter.

Specifically, we share DRA's conclusion that factors leading to last winter's severe curtailment should be non-repeating this year. Even including consideration of last year's curtailment, however, we find that DRA has demonstrated that the maximum curtailment period would be 18 days. We find, therefore, that under these circumstances the 15-day curtailment period forecast by DRA is reasonable.

With respect to LSFO oil prices, we again find DRA's testimony to be persuasive. DRA's independent forecast was well-supported and is not dramatically different from that asserted by Edison. Having adopted DRA's estimates of the two components determining oil generation expense, we therefore adopt DRA's forecast of $24.8 million for the forecast period.

c. Purchased Power Generation and Expense

Edison and DRA differed in their forecasts of purchased power generation and expenses by approximately $33 million. This difference is largely attributable to differences in their forecast gas prices. CCC/CSC, however, took issue with the approaches used by both Edison and DRA in forecasting economy energy availability.

(1) QF Purchases and Expense

With respect to the quantity of QF power estimated for this forecast period, DRA and Edison eventually agreed to a level of 14,446 gigawatt-hours (gWh) for the forecast period. On the issue of the capacities projected for four large QF projects, DRA and Edison reached a compromise between their original estimates. CCC/CSC remained supportive of Edison's original projections of capacity factors for the four QF facilities, but neither provided nor cited any evidence in support of this position.

Based on the record, we find the agreement between DRA and Edison related to the quantity of QF power and the capacity factors projected for the four large QF projects to be a reasonable

compromise of the forecasts presented. We therefore adopt the stipulated quantity and capacity factors.

Despite this agreement between Edison and DRA, in its brief DRA recites its concerns with Edison's record-keeping related to the level of QF generation. Specifically, DRA states that due to the size of this expense item, approximately 40% of Edison's total forecast energy expenses, DRA closely examined the assumptions underlying Edison's forecast of QF generation. DRA states that its witness found that in this proceeding, as in other recent Edison ECAC proceedings, Edison had failed to adequately determine the status of QFs not on line. DRA also states that reliable information about individual QF projects was difficult to obtain.

Of particular concern to DRA was that Edison had no written record of each QF contract nor a systematic method of keeping a record of their status. Specifically, DRA found discrepancies in the dates of operation assumed by Edison and the actual operating dates expected by the QFs.

Based on this history, DRA had originally recommended in this proceeding that Edison be required "to provide all QFs with a written data request regarding [their] operational data and to make such data available to DRA with its ECAC data response each year." (Exhibit 23, at p. 11-9.) In its testimony, DRA had included an outline of and timetable for the survey to be provided to QFs. Because of Edison's agreement during this proceeding to work with DRA to develop a mutually acceptable survey, however, DRA concluded that a Commission order on this issue was no longer necessary.

In the ALJ's proposed decision in this proceeding, the development of a QF survey like that originally proposed by DRA was included as an ordering paragraph. In their comments on the proposed decision, however, Edison, DRA, and CCC/CSC each objected to this approach. Edison states that the proposed order was an

unnecessary abrogation of an agreement between itself and DRA. Edison and CCC/CSC assert that because of the agreement they did not raise objections which each had to the survey form during hearings. DRA also questions the loss of flexibility in implementing such a survey. IU, however, endorses the ALJ's proposed order as a means of holding Edison to a more exacting level of accountability relative to QF expense data.

Because of the parties' inability during hearings to fully address DRA's proposed survey format due to Edison's and DRA's agreement, we will not include the ALJ's proposed order directing the implementation of the survey in this decision. We remain concerned, like IU, however, with the need to ensure the most accurate information regarding QF generation and costs. For this reason, we strongly urge Edison and DRA to work toward the development and completion of an appropriate QF survey format for Edison's next ECAC proceeding.

(2) Firm Purchases and Expenses

DRA and Edison agree on purchased power quantities from SCE Hoover, Mexico geothermal, Pacific Northwest firm purchases, California, SCE-renewable/alternative sources, and PURPA purchases. DRA forecast slightly lower Cholla generation (34 gWh) due to ELFIN dispatch. Edison's and DRA's forecasts of firm purchased power expenses differed due to the difference in forecast Cholla generation and the impact of different gas price forecasts on Pacific Northwest firm purchase contracts and PURPA expenses. DRA forecasts approximately $12.5 million less PURPA expense than Edison due to its lower gas price forecast and lower IER.

As previous discussion has made clear, we have adopted DRA's gas price forecast and approved DRA's use of ELFIN for determining revenue requirement. Given those circumstances, we find that the final firm purchase power expense level should be closer to that forecasted by DRA than by Edison. The final IER figure which we will adopt in this proceeding, however, may not

mirror DRA's because of assumptions which we have adopted in this decision (infra) which differ from DRA's. For this reason, DRA will be required to re-examine this forecast to determine the change in revenue impact, if any, caused by any change in its IER value resulting from the assumptions adopted in this decision. This change should be reflected in DRA's ELFIN run undertaken during the comment period to develop Edison's final revenue requirement.

(3) Non-Firm Purchases and Expenses

The determination of non-firm purchases and expenses are based on forecasts of Pacific Northwest (PNW) and Pacific Southwest (PSW) economy energy availability and cost. In developing the prices for PNW and PSW economy energy, DRA and Edison agreed to an algorithm that describes the relationship between the natural gas price and the expected quantity of energy that would be purchased. In making its recommendation, Edison relied solely upon the algorithm as set forth in Exhibit 37, while DRA used the result of the algorithm as an input to ELFIN and relied upon the resulting ELFIN output.

In addition to DRA and Edison, the CCC/CSC participated on the issue of PNW economy energy availability. The CCC/CSC made its own evaluation of this availability.

(i) Pacific Northwest Economy Energy

DRA and Edison agree on the quantity of PNW economy energy purchases. These parties also agree that the quantity of energy available from the Pacific Northwest should be capped to reflect a dry hydro year. The difference in Edison's and DRA's forecast of PNW non-firm purchased power quantity and expense is due solely to the impact of the differences in DRA's and Edison's gas price forecasts. For PNW power, the parties believe that the algorithm contained in Exhibit 37 and DRA's ELFIN run should produce the same results once the same gas price forecast is used.

CCC/CSC disputes the availability of PNW economy forecasted by DRA and Edison. CCC/CSC notes that DRA and Edison have projected a three-month period of economy energy availability, while CCC/CSC forecasts that PNW economy energy will be unavailable for a seven month period from June 1988 through January 1989. CCC/CSC argues that its evaluation of PNW economy energy availability is based on an expert understanding of both the operating requirements and current conditions in the Pacific Northwest. In contrast, CCC/CSC finds the substance of DRA's and Edison's algorithm to be that the "present will be reflective of the past." (Exhibit 32, at p. 40.)

In reviewing the record on this issue, we are not convinced that CCC/CSC has adequately demonstrated that a seven-month period of zero-availability of economy energy power is likely to occur. Neither do we find that CCC/CSC demonstrated that the algorithm relied upon by DRA and Edison was seriously flawed. We find, under these circumstances, that the three-month period of zero-availability projected by DRA and Edison is a more reasonable forecast of future availability of PNW power.

Given our adoption of DRA's forecast gas price and use of ELFIN to develop Edison's revenue requirement, we find DRA's forecast of PNW economy energy availability and expense to be reasonable. The record does not support rejection of either the algorithm relied upon by Edison and DRA or its use in the ELFIN model.

(ii) <u>Pacific Southwest Economy Energy</u>

DRA and Edison differ on both forecast quantity and expenses for Pacific Southwest purchases. The difference in price is again due to a difference in gas price forecasts. The parties agree, however, that the difference in forecasted quantity would not be great if the same gas price forecast were used. CCC/CSC disagrees with DRA's and Edison's

approaches for their failure to impose a ceiling on PSW economy energy availability.

According to CCC/CSC, the algorithm developed by Edison is designed to determine the amount of PSW economy energy which can reasonably be expected at various gas and fuel prices. CCC/CSC states that the formula, based upon historical data, was developed in theory as a basis for determining the ceiling level of PSW economy purchases which the ELFIN model could "take" in its determination of available resources.

CCC/CSC adopted the Edison regression formula as the basis for determining the ceiling for PSW availability. However, CCC/CSC asserts that a review of the Edison and DRA base case ELFIN runs reveal that neither party maintained the ceilings resulting from this formula. CCC/CSC states that reflecting availability in excess of the regression ceiling is to suggest that the system can purchase power at a favorable price when the regression formula indicates that such power does not exist.

CCC/CSC also is concerned that while DRA alternatively embraced and repudiated the regression formula, it preferred to let ELFIN model the availability of PSW. CCC/CSC states that DRA apparently supported their ELFIN "QF-Out" takes of PSW economy because they were relatively close to the regression's results. CCC/CSC argues, however, that DRA's final base case recommendation revealed a dramatic difference between the regression at the DRA gas price and the ELFIN model output--2,329 gWh versus 2,688 gWh.

Edison states that it attempted to model PSW economy energy to reflect market-determined incremental cost conditions and then permitted ELFIN to determine the quantity of PSW economy energy "to take" based on economics. In contrast, Edison asserts that CCC/CSC's imposition of a ceiling has the effect of "hardwiring" the model so that it takes as much PSW economy energy as the regression equations imply. Edison believes

that CCC/CSC has offered little support for pegging the price of PSW economy energy in each month to be exactly proportional to the dispatch price of gas. Edison believes that its approach is more appropriate, especially given concerns expressed about "hardwiring" during the workshops preceding hearings in this proceeding.

DRA objects to CCC/CSC's claim that DRA's ELFIN-generated results are in error because DRA's "QF-Out" ELFIN run (2,688 gWh) differed from the PSW algorithm result of 2,329 gWh. DRA believes a more appropriate comparison would be between the algorithm and DRA's updated "QF-In" run. DRA notes that its updated "QF-In" run (2,401 gWh) resulted in only a 72 gWh difference from the PSW purchases (2,329 gWh) predicted by the algorithm. Furthermore, DRA states that its PSW purchase forecasts are well within the benchmark range of 3,000 to 3,200 gWh identified by DRA witness Lafrenz as a test of the reasonableness of the ELFIN modeling results.

Based on our adoption of DRA's gas price forecast and the use of the ELFIN model to develop Edison's revenue requirements, we find reasonable DRA's forecast of PSW economy energy availability and expense. The apparent small difference in quantity between ELFIN and use of the algorithm alone do not suggest flaws in either methodology.

We do not share, however, CCC/CSC's insistence on a ceiling for PSW economy energy availability. Specifically, we do not find sufficient support in this record for adopting such an approach at this time. We suggest, however, that the parties continue to explore the efficacy of "hardwiring" the ELFIN model in the IER workshops held in future ECACs.

We note that CCC/CSC's request for a ceiling on PSW economy energy availability is part of its overall argument for "audit controls" on ELFIN results. This argument is discussed at greater length in our review of QF payment issues.

d. Coal Generation and Expense

Edison's and DRA's forecast of coal generation and expense are very close, separated by a difference of only $248,000. This minor difference is attributable to different gas prices and ELFIN dispatch of Mohave. Given our adoption of DRA's forecast gas price and DRA's use of ELFIN to determine Edison's revenue requirement, we find reasonable DRA's forecast of coal generation and expense.

Edison and DRA also agree on the recommended coal inventory level for the forecast period. In addition DRA and Edison agree that coal inventory carrying costs should be calculated using the latest DRI forecast of three-month commercial paper rates plus 25 basis points. Edison's and DRA's agreement on these issues is reasonable and should be adopted.

2. Fuel Inventory Levels, Carrying Costs, and Ratemaking Treatment

a. Fuel Oil Inventory

(1) Fuel Oil Inventory Level

Edison and DRA forecast oil inventory levels of 6.3 million barrels and 4.4 million barrels respectively. Specifically, Edison and DRA agree on a dead storage inventory requirement of 1.0 million barrels, but differ on station inventory requirement and system inventory requirement.

The station inventory requirement refers to the amount of oil necessary to maintain adequate distribution logistics for Edison's oil pipeline, storage, and receiving facilities. The system inventory requirement is composed of (1) displacement oil, required for supporting oil movement through the pipelines, (2) oil required to float tank roofs, and (3) potential oil burn (POB), that component of oil inventory needed to meet forecast oil burn requirements prior to replenishment. For station inventory requirement, Edison forecasts a level of 2.0 million barrels, while

DRA forecasts 1.5 million barrels. With respect to system inventory requirement, Edison forecasts 3.3 million barrels and DRA forecasts 1.9 million barrels.

Edison asserts that an adequate level of oil inventory is required to ensure reliable electric service to its customers. Edison states that its oil inventory recommendation of 6.3 million barrels provides a reliability of 96 percent while DRA's recommended oil inventory level of 4.4 million barrels would provide a reliability of less than 45 percent. In Edison's opinion, this level of reliability creates an unacceptable risk to Edison's customers. Additionally, Edison notes that it has never carried an average oil inventory at the level recommended by DRA.

Edison states that its forecast of 2.0 million barrels for station inventory is the minimum level of oil needed on site at Edison's generating stations to guarantee uninterrupted operation of Edison's oil/gas-fired facilities when gas service is curtailed. Edison's forecasted POB comprises 86% of its system inventory forecast of 3.3 million barrels.

DRA states that its recommended 4.4 million barrel fuel oil inventory is the same inventory level that was approved less than a year ago in D.87-11-013, at which time Edison had requested a 6.0 million barrel inventory. It is DRA's opinion that Edison has not demonstrated the need for an increase over that authorized level even though it now requests a 6.3 million fuel inventory.

Specifically, DRA believes that neither reason offered by Edison (i.e., expected level of gas curtailment and alleged changes in Edison's oil resupply strategy) supports the increase in fuel oil inventory requested by Edison. DRA states that its gas availability analysis indicates that adequate gas supplies will be available and the 1.9 million barrels authorized for last year will be sufficient. DRA adds that Edison still has contractual rights under the Chevron Option Agreement to purchase

up to 2 million barrels per month, which has the effect of lowering Edison's LSFO inventory.

DRA also asserts that its direct testimony and cross-examination of Edison's witness in this proceeding demonstrated that Edison was using the same resupply strategy as it had in the last ECAC period, and that any intended changes had not as yet actually taken place. DRA notes that Edison also testified that the intended changes would result in less rapid delivery of oil. DRA asserts that slower delivery will decrease, not increase, reliability.

In response to Edison's assertion that the 4.4 million barrel level recommended by DRA would yield only a 45% reliability level, DRA states that a comparison with a similar analysis used by Edison in its 1987 ECAC is instructive. Specifically, DRA states that from the 1987 ECAC to the 1988 ECAC, Edison's predicted reliability for 6.3 million barrels dropped less than 2% (from near 98% to near 96%). By contrast, DRA notes that, according to Edison's testimony, the 4.4 million barrel level recommended by DRA is predicted to drop a precipitous 24% in reliability from the 1987 ECAC to the 1988 ECAC. DRA states that Edison failed to substantiate the basis for this dramatic change in projected reliability.

As stated in previous sections, we have found DRA to have made a reasonable forecast of gas curtailment in the current ECAC forecast period. We do not find sufficient evidence in this record supporting the changes which Edison asserts require fuel oil inventory level over the level adopted in its 1987 ECAC. DRA has noted the many portions of Edison's testimony where Edison has failed to adequately demonstrate this increased need. We therefore find reasonable and adopt DRA's forecast of a 4.4 million barrel fuel oil inventory level.

(2) Fuel Oil Inventory Carrying Costs

The difference between DRA's and Edison's fuel oil inventory carrying costs is attributable to differences in their forecasts of the appropriate fuel oil inventory level for the forecast period. Both parties forecast carrying costs using short-term interest rate forecasts plus 0.25 percent for administrative costs. Having adopted DRA's fuel oil inventory level for the 1988 forecast period, we will therefore similarly adopt DRA's fuel oil inventory carrying costs.

(3) Fuel Oil Inventory Ratemaking Treatment

DRA and Edison agree on the ratemaking treatment for fuel oil carrying costs, variations from adopted levels, and gains or losses. Specifically, the parties agree that treatment of these items should remain the same as adopted in D.87-11-013. That order provided as follows:

> "Consequently we will treat Edison's oil inventory levels and cycling amounts as follows. Edison will be authorized ECAC-AER rates at the 4.4 million barrel level. Edison will establish a memorandum account that will debit 90% of carrying costs, at the short-term interest rate, on the difference between recorded inventory levels and the authorized 4.4 million barrel level. It will also debit 90% of any losses (or credit 90% of any gains) incurred in cycling fuel oil. The account balance will be considered in Edison's next ECAC case with Edison bearing the burden of proof that the actual inventories and purchases and sales were reasonable, for possible recovery of the memorandum account balance through ECAC rates." (D.87-11-013, at p. 30.)

Consistent with the preceding approach, DRA and Edison recommend that any fuel oil sale loss be recorded in the memorandum account with the opportunity for future recovery.

Edison notes, however, that it had first requested that fuel oil inventory carrying costs be made subject to the

ECABF/AER percentage allocation so that such expenses would be given ratemaking treatment consistent with other fuel and purchased power expenses. However, due to time constraints, it ultimately agreed with DRA to follow the ratemaking treatment adopted in D.87-11-013. Edison asks, however, that to the extent that the Commission establishes different accounting procedures for fixed oil inventory carrying costs in PG&E's 1988 ECAC proceeding (A.88-04-005, A.88-04-035), the same procedures be adopted for Edison.

Consistent with the DRA's and Edison's agreement, we will continue in effect the ratemaking treatment adopted in D.87-11-013 for Edison's fuel oil inventory carrying costs. The fact that different procedures might be adopted for PG&E, however, does not necessarily warrant or require their mandatory application to Edison. In Edison's next ECAC, hopefully sufficient time will exist for Edison to demonstrate the need for an accounting approach different from that adopted in this proceeding, if one is warranted.

b. Coal and Nuclear Inventory Carrying Costs and Ratemaking Treatment

DRA and Edison agree that the forecast coal inventory should be approximately 392,000 tons at Mohave and 226,000 tons at Four Corners. DRA and Edison agree that coal inventory carrying costs should be calculated based upon the estimated short-term debt interest rate plus financing issuance costs of 0.25 percent. DRA recommends use of the latest Data Resources Inc. three-month commercial paper rate.

DRA and Edison also agree that nuclear inventory carrying costs should be approximately $25.3 million. Edison states that DRA did not object to Edison's proposal that nuclear fuel inventory should be financed with a blend of short-term and intermediate-term debt.

With respect to the ratemaking treatment of coal and nuclear inventory, the Commission in D.87-12-066 transferred the rate recovery of coal and nuclear inventory carrying costs from base rates to ECAC rates effective January 1, 1988. The Commission ordered that coal inventory carrying costs should be calculated using short-term debt interest rates and be included 100 percent in the ECAC balancing account. For nuclear inventory carrying costs, the Commission ordered that these costs be calculated using ECAC interest rates and included 100 percent in the ECAC balancing account.

Initially, Edison proposed further ECAC tariff modifications so that coal and nuclear inventory carrying costs would be subject to the ECABF/AER percentage allocation commencing June 1, 1988. Later Edison agreed to withdraw this request if the presently authorized 100% ECAC balancing account treatment of coal carrying costs remained in effect. Because DRA recommended "lump sum" ratemaking, rather than 100 percent balancing account, treatment, however, Edison returned to its original request that the recorded and adopted carrying costs associated with nuclear fuel inventory and coal inventory be subject to the ECABF/AER percentage allocation.

In the alternative, Edison proposed that, for consistency with the present fuel oil inventory ratemaking treatment adopted in D.87-11-013, a memorandum account could be authorized to record variations in carrying costs due to inventory level changes and gains or losses on sales. Edison believes, however, that Commission authorization is required to create such an account.

DRA believes that Edison's adopted carrying costs should be fully recoverable through the ECAC balancing account. However, in DRA's view, the authorized carrying costs should be considered as the "lump sum" total of Edison's authorized carrying costs. DRA proposes a "true-up" of the interest rate at the end of the forecast period. According to DRA, this "true-up" would permit

Edison to recover its authorized carrying costs based on the actual interest rate over the forecast period. DRA states that if Edison's actual carrying costs differ from the authorized level, then Edison may apply for recovery of the shortfall or return of the excess. DRA states, however, that it would not oppose authorization of memorandum accounts for coal and nuclear fuel inventory carrying costs.

Edison believes that DRA's "lump sum" proposal is inconsistent with the ratemaking treatment adopted for Edison's fuel oil carrying costs in D.87-11-013 and for San Diego Gas and Electric Company (SDG&E) in D.87-12-049 in its 1987 ECAC proceeding. Edison notes that the Commission rejected DRA's "lump sum" approach in D.87-12-049 because it would single out fuel oil inventory for different ratemaking treatment. Edison states that the Commission in that decision also concluded that such isolated treatment could result in perverse incentives for utility management to focus on inventory costs more than other energy costs.

As Edison correctly points out, the Commission in D.87-12-069 declined to adopt DRA's "lump sum" approach for fuel oil inventory carrying costs. We took this step not because of some inherent flaw in such an approach, but rather because we could find no explanation why this particular energy expense should be segregated from other expenses and given different treatment. We expressed concern, as noted by Edison, that such an approach could "create perverse incentives for utility management." (D.87-12-069, at p. 11.)

Given our continuation of a memorandum account for fuel oil inventory carrying costs, we find that the only reasonable approach is to direct Edison to create similar accounts for its nuclear fuel carrying cost and coal inventory carrying costs. Edison will therefore be entitled to recover 100% of its adopted nuclear fuel and coal inventory carrying costs in ECAC and will be

authorized to record in memorandum accounts, for later potential recovery through ECAC variations in these carrying costs due to differences in inventory levels from the authorized levels and gains or losses on sales. Consistent with the agreement between Edison and DRA in this proceeding, Edison is also authorized to finance nuclear fuel with a blend of short- and intermediate-term debt.

3. Franchise Fees and Uncollectible Accounts Expense and Resale Accounts Allocation

A $1.0 million difference between DRA and Edison for franchise fees and uncollectible accounts expense and resale accounts allocation is due solely to differences in forecast fuel, purchased power, and energy-related expense. Based on our adoption of DRA's forecasts and its use of the ELFIN model to develop Edison's revenue requirement, we find reasonable DRA's methodology for calculating franchise fees and uncollectible accounts expense and resale accounts allocation.

G. QF Payment Components

This ECAC marks the beginning of the Commission's regular annual updating of variable QF payments in the utilities' ECAC proceedings. In this section, we will focus on the calculation of the utility's variable QF capacity and energy payments and, in particular, the ERI and IER used in determining those payments.

With the aid of the workshops held in advance of hearings in the forecast phase, the parties were able to reach agreement on many of the resource assumptions and modeling issues impacting the calculation of Edison's IER. This procedure has greatly enhanced consideration of these complex issues in this hearing process and should be continued.

Nevertheless, several issues related to QF energy payments remained in dispute. With respect to resource assumptions used to determine both Edison's IER and revenue requirements, those issues have been addressed in the previous section. In this

section, we will therefore focus on the remaining issues in dispute impacting the IER calculation and QF energy payments. These issues include the selection of a commit target variable, the substitution of cold-standby units in the "QFs-Out" run, and consideration of forced outages in determining system capacity.

In our discussion of QF energy payments, we will also consider the more generalized debate among the parties regarding the efficacy of each party's approach to ELFIN, the validity of proposed reasonableness tests of ELFIN produced results, and the introduction by the CCC/CSC of new IER runs in its opening brief. In addition, we will also examine Edison's avoided cost of gas and the fixed gas component reflected in QF energy payments.

Testimony on these issues was presented by Edison, DRA, and the CCC/CSC. During the course of hearings, these parties reached agreement on the value of Edison's ERI. No agreement, however, was reached with respect to the IER.

1. ERI Stipulation

During hearings in this proceeding, Edison, DRA, and the CCC/CSC stipulated that 0.43 was a reasonable value for Edison's ERI. We understand that these parties had a full opportunity to review the bases for each of their recommendations. We have in turn reviewed the stipulation and conclude that 0.43 is a reasonable value for Edison's ERI and should be adopted. Late-filed Exhibit 77, DRA's updated revenue requirements showing, incorporates this stipulated value.

2. IER and QF Energy Payment Issues

The Commission has determined that IERs are to be calculated using the "QFs In /QFs Out" methodology. (D.88-03-079, at pp. 29-32.) The "QFs In/QFs Out" simulation involves two model runs. The first or "QFs In" run "represents system dispatch with all variably priced QFs anticipated to be on-line during the forecast period." (Id., at p. 23.) The second or "QFs Out" run "represents the projected dispatch of the system with all variably

priced QFs removed." (Id.) The IER is based upon the difference in costs between the two runs, divided by the quantity of variable priced QFs.

While the Commission in D.87-12-066 required that ELFIN be used by each party for a "base case" IER calculation, the parties were also entitled to present IER recommendations based on production cost models of their choice. In this proceeding, however, no party chose to present results from a production cost model other than ELFIN.

a. **Parties' Positions on Overall IER Development and Recommendations**

With gas as the marginal fuel, the parties' annual average IER recommendations are as follows:

Edison	9,650 Btu/kWh
DRA	9,533 Btu/kWh
CCC/CSC	10,116 Btu/kWh

These IER recommendations reflect each party's resource assumptions, rather than those adopted by the Commission in this decision. Additionally, DRA's presently recommended IER of 9,533 Btu/kWh represents a reduction from DRA's previous IER of 9,661 Btu/kWh.

In its opening brief, CCC/CSC criticized DRA's and Edison's approach and expertise in using ELFIN. Specifically, CCC/CSC asserts that Edison's and DRA's analyses are based upon flawed or inconsistently applied input assumptions and modeling conventions, a failure to reflect the operating realities of the Edison system, and a continued historical pattern of systematically overestimating forecast average system heat rates and underestimating forecast IERs.

The source of these problems, in CCC/CSC's view, lies primarily in DRA and Edison failing to conduct reasonableness reviews of their ELFIN results and to impose "audit controls" to ensure consistency in ELFIN's outputs with actual system operation.

In particular, CCC/CSC argues that ELFIN results should be reviewed (1) to ensure that forecast IERs reflect historical IERs and heat rates, (2) to ensure that concerns with revenue requirement do not dictate IER results, (3) to constrain the ELFIN run in providing estimates of PSW economy power, and (4) to ensure that IER levels vary with a decrease in resources between the "QFs-In" and "QFs-Out" runs. We have previously discussed the constraint of PSW economy energy results in our section on Edison's adopted resource mix.

In its opening brief, CCC/CSC sought to show the impact on the parties' IER results of its "audit controls" and the assumptions which CCC/CSC identified as the "benchmark standards" (i.e., the commit target value, the treatment of substitution units, PSW modeling, and gas dispatch prices). To this end, CCC/CSC presented the results of sensitivity runs on ELFIN using the varying positions of the parties. Using the values it assigned to the "benchmark standards", CCC/CSC recited IER values for DRA and Edison significantly increased over those recommended by the parties.

CCC/CSC states that it is offering these sensitivity runs as "additional arguments" and "extensions of the theories presented in the evidentiary record." (CCC/CSC Opening Brief, at p. 7.) CCC/CSC further states that "these integrated assessments [are] offered to show and support the 'robustness' of CCC/CSC's result", but not "as alternative recommendations to the evidentiary record." (CCC/CSC Opening Brief at pp. 7 & 28.)

In its opening brief, Edison challenges the CCC/CSC's choice of using the 1987 recorded IER data to judge the reasonableness of the IER forecasts of Edison, DRA, and CCC/CSC. Such a comparison, according to Edison, is misleading in that it implicitly assumes that conditions during 1987 will be the same as the 1988 ECAC forecast period. Edison states that, in fact, conditions during 1987 were very unusual and are not expected to be

repeated during the forecast period. In making its comparison, Edison charges that CCC/CSC has chosen only to look at the highest recorded value for IERs in the last three years.

Edison also believes that, in judging the reasonableness of ELFIN results, it is erroneous to compare average heat rates to incremental heat rates. Similarly, Edison asserts that it is erroneous to assume that the IER level must change in response to a decrease in available resources.

Edison also objects to CCC/CSC's offering new ELFIN runs in its brief to "prove" the efficacy of CCC/CSC's approach to ELFIN modeling or the assumptions upon which it relied. Edison states that CCC/CSC's proposals go well beyond sensitivity analyses and are a blatant example of CCC/CSC introducing improper, invalidated computer runs in its briefs. In Edison's view, CCC/CSC's analyses are facts, not legal theories, requiring cross-examination. In this regard, Edison observes that it has been unable to duplicate CCC/CSC's results and therefore must assume that CCC/CSC's IERs are supported by assumptions which are not part of the record.

DRA similarly responded not only to CCC/CSC's new sensitivity runs, but also to its claims that DRA's IER was "unaudited" and "a classic counter-intuitive model result." (CCC/CSC Brief, p. 9.) DRA states that CCC/CSC's "attack" on DRA's model results is without any basis in the record. According to DRA, CCC/CSC has not explained what is meant by "unaudited" ELFIN results and has failed to demonstrate any errors in DRA's methodology.

DRA joins Edison in objecting to CCC/CSC's claim that forecasted IERs should reflect recorded IERs or that the IER should necessarily have increased "because of the need to start up additional oil and gas fired units to meet the increased need for capacity." (CCC/CSC Brief, p. 9.) According to DRA, of the total reduction in energy between the "QF In" and QF Out" runs, a significant part was due to decreased PNW economy energy. DRA

states that there would not necessarily be an increased need for capacity when economy energy is reduced since economy energy does not count toward spinning reserve.

Like Edison, DRA challenges CCC/CSC's attempt in its opening brief to offer new, totally unsubstantiated "sensitivity" analyses of both Edison's and DRA's latest IER figures. DRA notes the impropriety and fundamental lack of fairness of CCC/CSC's tactics. DRA and Edison both note that no work papers supporting these runs were offered to either party nor was there any notice of CCC/CSC's intent to submit new "evidence" in its brief. DRA states that it was therefore denied an opportunity to cross-examine CCC/CSC on this new evidence or to make timely data requests or analyses.

We are constrained in this proceeding by the limited amount of time available to hear and resolve Edison's 1988 ECAC forecast phase. This circumstance has produced procedural results which we hope may be avoided in Edison's next ECAC. It obviously would have been preferable to split the forecast phase into two parts--one for the adoption of resource mix and IER assumptions and the second for reviewing and adopting results based on parties' recommendations using those assumptions. In this way, the parties would have had an opportunity during the second hearings to discuss any "reasonableness tests" or "control audits" which should be applied to their ELFIN results based on the adopted assumptions. While such an approach was not feasible in this proceeding, we believe that our adopted procedures provided all parties a full and fair opportunity to litigate the issues in this proceeding.

Unlike the revenue requirement and resource mix assumptions previously discussed, the ALJ's proposed decision, with which we are in agreement, did not uniformly adopt any single party's position for each of the remaining disputed issues related to QF payments. It was therefore necessary for the parties to "re-run" their ELFIN models using the adopted values and provide

their updated IER recommendations during the comment phase following the issuance of the ALJ's proposed decision. Each of these runs have been made a late-filed exhibit in this proceeding.

Although there was not an opportunity to examine these revised recommendations in a hearing setting, we believe that such "testing" of these results was not necessary. Specifically, through several days of workshops and many days of hearings, the parties became well-acquainted with the modeling approaches each had used. CCC/CSC's brief appears to suggest that post-processing "reasonableness tests" would have altered DRA's and Edison's IERs. However, a closer examination of CCC/CSC's "new evidence" reflects that the changes in DRA's and Edison's IERs were dependent on the values assigned to the four "benchmark standards." These standards are no more than four of the values at issue in this proceeding. Once these issues were resolved in the ALJ's proposed decision, we find, as even CCC/CSC suggested would occur, that only slight differences in the final IERs have resulted.

The latitude which we lose in this proceeding due to its short time-frame is the ability to adopt methodologies, as suggested by CCC/CSC, instead of absolute values and to permit individual "reasonableness" tests of end-results. As an example, we have in fact chosen commit target values in this proceeding instead of a methodology as urged by CCC/CSC. This conclusion, however, does not mean that in future ECACs a methodology or an "iterative" approach might not be selected by the Commission followed by hearings which would permit the examination of each party's application of that methodology.

Until that time, however, we believe that the record in this proceeding supports our adopted values and our consideration during the comment phase of IER recommendations based on those values. If there were concerns regarding the way in which a particular party used a model in this proceeding, the hearings which have already been held were the appropriate forum for raising

those concerns. In this regard, we find insufficient evidence, despite CCC/CSC's innuendos to the contrary, that Edison, DRA, or even CCC/CSC used the ELFIN model in an inappropriate way.

We also find that DRA and Edison have adequately responded and rebutted CCC/CSC's challenge to their modeling judgment. The only concrete suggestion offered by CCC/CSC as a means of judging the reasonableness of the parties' overall IER recommendations is how closely they mirror the past year's recorded IER. We find irony in CCC/CSC's reliance on the past in this instance, when it so strenuously objected to Edison's and DRA's algorithm used to develop economy energy quantities for its reflection of the past in the present.

Obviously, sole reliance on the past is not appropriate in any forecasting effort. While we would question an IER in one year which was significantly different from the previous year, we would logically look first to the assumptions made leading to that result. If the ultimate results presented by the parties during the comment phase using the adopted assumptions had differed considerably from each other or from the previously adopted IER, the Commission might have considered a need for additional hearings. In this case, however, the final proposed IERs of 9,759 Btu/kWh for Edison and 9,763 Btu/kWh for DRA and CCC/CSC were nearly identical and were very similar to Edison's currently adopted annual IER of 9,775 Btu/kWh. We find therefore that no further hearings or Commission action is required to adopt a final IER result in this proceeding.

As a final point, we concur with Edison and DRA regarding the impropriety of CCC/CSC introducing new sensitivity analyses in its opening brief. Whether CCC/CSC wished us to adopt the actual results presented in its brief or not is irrelevant to the issue of whether the material is evidence. Specifically, we find that any factual matter or expert opinion upon which a party intends the

Commission to rely as support for or a challenge to a particular position is evidentiary in nature.

We wish to distinguish CCC/CSC's actions from our decision to permit the parties to include final IER recommendations in their comments. We believe that, in the latter case, we attached sufficient procedural safeguards to this process to have permitted our consideration of these recommendations. In particular, we established that (1) each party would have the same opportunity to present their recommendations at the same time and under the same circumstances, (2) each of these submissions would be accorded the same status (late-filed exhibit), (3) the same assumptions would be used, (4) supporting work papers would be served on each party performing a model run, and (5) each party would have the opportunity to address the revised recommendations in their comment responses.

b. Remaining IER and QF Energy Payment Issues

(1) Addition of Standby Units in the "QFs Out" Run

At issue in this proceeding is whether cold standby units should be included in the "QFs-Out" run in calculating the IER, and, if so, what units are appropriately reflected in that run. Both Edison and DRA returned two cold standby units (Alamitos 3 and Huntington 3) to service for the forecast period in the "QFs-Out" run, while CCC/CSC objected to any standby units being added. CCC/CSC asserts that even if standby units could be added to the "QFs Out" run, Etiwanda 1 and 2 and San Bernardino 1 and 2 are the appropriate units to add. Further, CCC/CSC argues that their addition should be limited to the two-month period in which a capacity shortfall is projected.

Edison asserts that its approach in its "QFs-Out" run of adding the two standby units and valuing as-available capacity at less than 100 percent is justified. Edison states that logic dictates that as-available capacity is not worth the full cost of a combustion turbine (CT) as long as there are units on

cold-standby reserve that can be brought back to service for less than the cost of constructing CTs.

In support of its returning cold-standby units to service, Edison states that removing all variably priced QFs from the resource base without adding some resources to the "QFs Out" resource base would result in inadequate spinning reserve margins. Edison therefore concludes that, if these QFs were removed from the Edison system, its response would not be to run the existing system harder, but rather to return cold standby units to service.

According to Edison, in this scenario it chose to return Alamitos 3 and Huntington Beach 3 to service since both facilities can be returned to service quickly and at a fraction of the cost of constructing new generating facilities. In Edison's view, the addition of these two units to the "QFs-Out" run, results in an adequate spinning reserve margin for the "QFs-Out" run and correctly accounts for commitment costs in the IER calculation. In the long-term, Edison states that the Alamitos 3 and Huntington 3 units are more appropriate to return to service than the units suggested by CCC/CSC because they are more efficient. Edison also believes that it is reasonable to include these units in the "QFs Out" run each month of the forecast period.

As stated above, DRA agrees with Edison's position on the addition of Alamitos 3 and Huntington 3 as replacement units in the "QFs Out" run. DRA states that forcing ELFIN to assume that no units were available in months of capacity shortfall would not reflect the way the system would actually operate under those conditions, particularly when those units can be brought on-line within five days.

Both DRA and Edison assert that D.88-03-079 permits the inclusion of cold-standby units in the "QFs-Out" run. According to these parties, that order prohibits "substitute," and not "existing," resources from being added to this run. In Edison's and DRA's opinion, the prohibition in D.88-03-079

therefore applies to resources which have not yet been built as opposed to those already on the utility system, but placed on standby status until needed.

In contrast to this position, CCC/CSC specifically equates the "substitution units" excluded by D.88-03-079 from the "QFs-Out" run with the standby units included by DRA and Edison in their "QFs Out" run. CCC/CSC therefore asks the Commission to reject the inclusion of these units by DRA and Edison.

CCC/CSC states, however, that, if Edison and DRA are correct in their interpretation of D.88-03-079, changes must be made to their approach. Specifically, CCC/CSC recommends the following: (1) if there is a shortage of capacity as the infusion of substitution units suggests, then as-available capacity must be valued at 100%, (2) substitution units should only be brought back for the two months (August and September) during which Edison's testimony reflects a model projection of a possible shortage of capacity, and (3) the choice of units should be Etiwanda 1 and 2 and San Bernardino 1 and 2.

With respect to this last point, CCC/CSC notes that, while Edison chose to bring back Alamitos 3 and Huntington 3, in actual practice Edison has relied on Etiwanda 1 and 2 and San Bernardino 1 and 2 as standby units. CCC/CSC states that these units are far less efficient than the two chosen for the model runs.

In D.88-03-079, we concluded that the "QFs In/QFs Out" methodology should be used by all utilities for calculating variable energy payments for QFs. In reviewing that methodology, the Commission rejected the proposal to include "substitute" units in the "QFs Out" run. The Commission in defining this issue was referring to the circumstance in which "a utility will incur energy-related capital costs to add a new resource (in order to lower its operating costs) rather than run its existing system harder." (D.88-03-079, at pp. 25-26.) Specifically, the Commission

rejected the placing of "a cap on variable energy prices whenever a utility has so many short-run QFs on its system that it would substitute a new resource to lower its operating costs if all these QFs were removed from its resource plan." (Id., at p. 26; emphasis added.)

The meaning which we intended to give the phrase "substitute units" in D.88-03-079 has therefore been correctly interpreted by DRA. A substitute unit is a "new" resource added in response to the absence of short-run QFs and not an "existing" unit returned from cold standby to fill an intermittent loss of capacity. We anticipate, and expect, those performing a "QFs Out" run to return cold standby units to service in response to such a shortage in capacity.

While we believe that it is appropriate to include standby units in the "QFs Out" run to mirror reality, we similarly believe that the type of unit returned to service and the length of time for which it is returned should also reflect actual system operations. We find that CCC/CSC has demonstrated that the units which should be returned under these circumstances should not be Alamitos 3 and Huntington 3 and that the need for standby units exists in only two, and not twelve, months of the forecast period. In this regard, we are concerned that Edison would be keeping any "efficient" unit on standby status. Further, while Edison argued that the efficiency of the unit was important because of the "long-term" resource need, we question the necessity of reflecting a long-term resource need in variable QF energy payments.

We therefore adopt CCC/CSC's recommendation to return to service Etiwanda 1 and 2 and San Bernardino 1 and 2 in the two-month period in which a capacity shortage was forecast. However, because the parties have stipulated to an annual IER value of 0.43, we will not adopt CCC/CSC's proposal that, during this period of capacity shortfall, as-available capacity should be valued at 100%.

(2) Accounting for Forced Outages

Both DRA and Edison reduced or "derated" system capacity to account for forced outages as well as maintenance. In challenging DRA's and Edison's approach, CCC/CSC states that derating capacity for both maintenance and forced outages artificially and inappropriately lowers the reasonably expected availability of Edison capacity.

In contrast, CCC/CSC states that its approach, to derate capacity for maintenance outages only, reflects Edison's actual system operations. CCC/CSC believes that its method also avoids double counting for forced outages--once in the available capacity and again in the spinning reserve commitment. In using its approach, CCC/CSC further states that there will be ample spinning reserve to cover Edison's spinning reserve requirements in the CCC/CSC base case.

DRA states that ELFIN, in modeling the future, is unlike a real system operator who will actually know whether a resource is subject to a forced outage at the time a commitment decision must be made. DRA asserts that the duration of capacity to reflect forced outage rates provides ELFIN with the next best (and only) information which can be provided a model-it describes the probability of a forced outage at any given time. In DRA's view, failure to provide ELFIN with information on the forced outage rates of the resources it commits will systematically overstate the probable capacity available to the system at a given time based on a given mix of committed resources.

Edison similarly finds CCC/CSC's approach flawed for its failure to recognize forced outages and its assumption that all committed units are available at 100 percent capacity for 100 percent of the forecast period. According to Edison, the result is that costs that would be incurred to bring additional units on-line when the committed units sustain a forced outage are ignored in the CCC/CSC modeling and in turn produce unrealistic results.

We find that CCC/CSC has made a valid point regarding the need to reflect the realities of Edison's system operations as closely as possible in forecasting the future through ELFIN. This reality, however, includes the "probability" of forced outages. We therefore find that it is reasonable for ELFIN to reflect this probability and its impact on the availability of Edison's system capacity.

In this proceeding, the only approach before us which achieves this end is that proposed by DRA and Edison. We therefore adopt DRA's and Edison's recommendation to de-rate capacity for forced outages and maintenance. CCC/CSC is, of course, welcome in Edison's next ECAC to develop and propose a different approach which it believes more precisely reflects this impact in an ELFIN run.

(3) Commit Target Variable Values

In determining Edison's IER, it is necessary for the production cost model that is used to accurately assess the costs of serving load. To this end, it must achieve about the same level of spinning reserves as maintained by system operators.

All parties in this proceeding relied on the ELFIN production cost computer model. In using ELFIN, the modeler cannot directly input a spinning reserve level, but instead relies on a "commit" variable to influence spinning reserves. This "commit target variable" is intended to tell ELFIN when to commit additional resources and permits the ELFIN modeler to specify a reserve margin. A commit value which is too high or too low results in either an over-commitment or under-commitment of units, respectively, to meet system load and spinning reserve requirements.

The monthly ELFIN commit target values relied upon by the parties are illustrated in the following table reproduced from Appendix A of DRA's concurrent opening brief. The table reflects DRA's changed commit target values resulting from the changed assumptions incorporated into the post-hearing ELFIN runs included in DRA's late-filed Exhibit 77.

Comparison of ELFIN Commit Target Values

	CCC/CSC (1)	DRA (2)	Edison (1)
1. June 1988	1.12	1.14	1.16
2. July	1.11	1.13	1.15
3. August	1.11	1.13	1.16
4. September	1.11	1.18	1.21
5. October	1.12	1.18	1.22
6. November	1.13	1.23	1.26
7. December	1.12	1.22	1.24
8. January 1989	1.22	1.24	1.26
9. February	1.24	1.28	1.29
10. March	1.24	1.26	1.29
11. April	1.22	1.25	1.27
12. May	1.19	1.21	1.23

(1) From Exhibit 64
(2) From DRA's late-filed exhibit (mailed June 17, 1988), Table 6-3L

Edison states that in determining its commit values it took into consideration the following two flaws which it found in the ELFIN commit logic: (1) the failure of the ELFIN commit logic to distinguish between firm resources and economy resources, and (2) the counting of all quick-start resources (combustion turbines) as contributing toward the commit target variable. Due to these deficiencies, Edison states that the ELFIN modeler must set the commit target higher than the desired spinning reserve target because some of the resources that ELFIN counts as contributing toward meeting the commit target do not in fact contribute toward spinning reserve.

Given these circumstances, Edison states that it developed its commit values by summing for each month the peak load, the spinning reserve requirement (7 percent of peak load or the largest single contingency, whichever is greater), the capacity of economy energy, and the capacity of combustion turbines. The resulting monthly sums were then divided by the peak load for each month to arrive at the monthly commit values. Edison states that this approach yields values which result in the spinning reserve target being achieved with those resources that properly contribute to spinning reserve.

Edison states that DRA and CCC/CSC followed a similar approach, but neither included the capacity associated with combustion turbines in setting their commit values. Additionally, Edison notes that DRA included an additional component omitted by both Edison and CCC/CSC. This component was the addition of 40 percent of the capacity associated with smaller QFs. Edison states that the result of both approaches are commit values lower than Edison, with CCC/CSC's being the lowest.

Edison asks the Commission to reject the CCC/CSC approach. In Edison's opinion, the absence of combustion turbines and non-spinning QF capacity in CCC/CSC's determination of its commit variable results in an undercommitment of spinning reserves.

Edison further states no work papers were produced by CCC/CSC reflecting a separate spinning reserve analysis which CCC/CSC had asserted supported the reasonableness of its results.

DRA states that its commit target is based on a ratio of two capacities. According to DRA, the numerator is the sum of peak capacity, seven percent of the peak capacity or the largest single contingency for spinning reserve, the total capacity of economy energy available during the peak hours, and forty percent of the forecast capacities of QFs under 40 megawatts. The denominator is the system peak capacity. DRA believes that its methodology for determining the commit value is straightforward and reasonable and should be adopted.

In developing a commit target value, it is CCC/CSC's position that the most important aspect is whether the value used creates model outputs which reflect the reality of the operating system. CCC/CSC therefore asks the Commission to endorse a methodology for deriving the commit value as opposed to the adoption of a specific commit value figure. CCC/CSC also requests that the Commission require verification that the model outputs commit system units in a manner which meets, but does not exceed, system load and spinning reserve requirements. In the absence of a commit value audit, CCC/CSC asserts that the Edison and DRA ELFIN models dramatically over-commit units resulting in high system heat rates and depressed IERs.

With respect to methodology, CCC/CSC states that its iterative methodology is different than and superior to the formalistic calculation used by DRA and Edison. CCC/CSC states that its methodology first requires determination of an initial value. This value is equal to the weekly peak load divided into the sum of the weekly peak load plus spinning reserve, the ELFIN capacity representation for PNW and PSW economy energy purchases, and 45% of the nonfirm purchases associated with resale load. The CCC/CSC then examines the initial commit number to determine if a

sufficient amount of capacity is committed to meet system peak load plus spinning reserve requirements.

Given the time constraints presented in this proceeding, we are not in a position to adopt a methodology for determining and adjusting the commit target variable like that proposed by CCC/CSC. As explained previously, the procedure which was required to be followed in this case, with ELFIN runs being performed during the comment period, would not have presented a sufficient opportunity for examination of each of the party's application of the methodology upon which two of the parties did not originally rely.

We find, however, that each of the parties' approaches to achieving a commit target value is similar and designed to meet the same goals--the determination of a reasonable system load projection. The only significant differences appear to be in the treatment of certain sources of capacity.

We therefore find that the record is sufficient to adopt specific commit target values in this proceeding. In our review of the parties' recommendations, we find that DRA's method includes those resource capacities which most appropriately should be considered in this calculation. Given this circumstance, and our adoption of DRA's resource mix assumptions, DRA's commit target values for the forecast period are reasonable and should be adopted.

(4) Post-Processing Adjustments

With respect to post-processing adjustments to ELFIN's output, DRA accounted for "general optimization" and start-up costs by escalating the heat rates flowing from ELFIN by 1.44 percent. CCC/CSC proposed a model adjustment of 30 Btu/kWh to account for start-up costs.

Edison states that while it does not disagree with a post-processing adjustment to reflect start-up costs, Edison believes that it is superfluous to add 30 Btu/kWh to account for

these costs. In Edison's opinion, ELFIN already overstates a reasonable level of start-up and no load in its no load estimate.

In D.87-12-066, the Commission concluded that any adjustment of ELFIN to account for start-up costs should not result in any "double-counting" of those costs. (D.87-12-066, at p. 207.) To avoid this result, which Edison apparently asserts could flow from CCC/CSC's approach, we will adopt DRA's recommendation to escalate ELFIN heat rates by 1.44 percent.

3. Gas Costs Reflected in QF Energy Payments

In our earlier section on revenue requirements, we adopted a gas price forecast which dictates the dispatch price of gas impacting the calculation of the IER. In addition, however, we must also consider the determination of the fixed gas cost and avoided cost of gas, both of which are reflected in QF energy prices.

In this proceeding, Edison and DRA used different methods for calculating the fixed gas cost included in QF energy prices. DRA calculated the average fixed gas costs by dividing the allocated fixed costs from the SoCal CAM proceeding by the gas volumes forecast in this ECAC proceeding. Instead of using the ECAC gas volumes as the denominator in calculating fixed gas costs, Edison used the gas sales forecast from the SoCal CAM proceeding.

It is Edison's position that to determine the average fixed gas costs, it is more consistent to divide the allocated fixed gas costs developed in the SoCal CAM proceeding by the gas sales volume which were developed in that same proceeding. In Edison's opinion, DRA's proposed methodology could cause QF prices to vary erratically if the gas sales forecast changes between the SoCal CAM proceeding and the ECAC proceeding.

Edison also believes that DRA's approach is premature and philosophically unsound. Edison states that it is unreasonable and unfair to reward QFs with higher payments when it is the unexpected increase in QF production, resulting in a decline in gas purchases

and an increase in average fixed gas cost, which causes the payments to be higher. Edison states that DRA has not yet provided Edison with a quantification of the amount of additional payments resulting from the higher prices paid to QFs.

DRA states that its approach is based on the methodology adopted by the Commission in D.86-10-045. In that decision, we ordered PG&E to use "the most recent forecast of gas burn adopted," which would be the more recent of the ECAC or the CAM forecasts. (D.86-10-045, at p. 3.) While DRA recognizes that D.86-10-045 involved PG&E's and not Edison's fixed gas costs, DRA asserts that QF payment methodologies under the standard offer contracts are intended to be uniformly administered among the three utilities that have such contracts. Based on this consideration, DRA urges the Commission to order Edison to conform to the methodology in D.86-10-045.

CCC/CSC believes that DRA's reliance on D.86-10-045 is reasonable. DRA's recommendation, in CCC/CSC's view, has the effect of making a consistent application of the Commission policy to use "the latest forecast gas burn adopted" for QF gas pricing.

We concur with DRA and CCC/CSC that, for consistency, the same approach for determining fixed gas costs announced in D.86-10-045 should be applied to Edison, as well as PG&E. Although this decision involved PG&E, Edison was fully aware of DRA's proposed application of the adopted methodology to Edison in this proceeding. Under these circumstances, Edison has therefore had an adequate opportunity to address the methodology and its application to Edison. In this regard, we do not find Edison's arguments sufficiently persuasive to adopt different approaches for the two utilities.

With respect to the reflection of avoided gas costs in QF energy payments, we note that the parties agreed to follow the approach adopted in the generic standard offer proceeding (A.82-04-044, et al.). On July 8, 1988, in that proceeding, the

Commission issued D.88-07-024 addressing gas costs avoidable by QFs.

In D.88-07-024, the Commission concluded that the variable energy payments to QFs should be calculated as follows:

> "Except for the customer costs, all gas utility fixed costs allocated to the UEG [utility electric generation] customer are avoidable. Also, the UEG customer's gas commodity costs are 100% avoidable by QFs. For an electric utility that takes noncore procurement service, the energy payment to QFs is calculated using the LDC's noncore portfolio WACOG. For an electric utility that elects service from both the core and noncore portfolios, the energy payment to QFs is calculated using an average of the two WACOGs, considering the relative volumes purchased by the electric utility from each portfolio." (D.88-07-024, Conclusion of Law 3, at p. 24.)

We adopt this approach in this proceeding and will direct Edison to determine its QF energy payments consistent with D.88-07-024.

H. Adopted ECAC Revenue Requirement and IER

We wish to commend the parties on their efforts during the comment phase to comply with the procedures outlined in the ALJ's proposed decision in this proceeding. As the ALJ predicted in that order, applying the adopted assumptions, DRA's revised revenue requirement was only slightly higher than its final recommendation during hearings, and the final IER recommendations were nearly identical.

In this regard, DRA proposes an approximate $388 million increase in the ECAC revenue requirement. Based on an ERI value of 0.43 and the adopted assumptions, CCC/CSC accepts DRA's final annual IER value of 9,763 Btu/kWh, while Edison proposes a final IER of 9,759 Btu/kWh.

We find reasonable and adopt DRA's final IER recommendations. We find that DRA has properly interpreted the ALJ's proposed decision and properly applied the adopted

assumptions and forecasts. This approach included the consistent application of an ERI of 0.43 in all twelve months of the forecast period and the weighting of the gas dispatch price by the number of days in the month.

Additionally, we concur with the time-differentiation factors applied by DRA to its annual IER. This approach resulted in the following IERs by time period:

	Summer	Winter
	(Btu/kWh)	
Peak	15,295	
Mid-Peak	9,184	11,271
Off-Peak	8,722	8,538
Super Off-Peak		8,038

We also find reasonable and adopt the level of fuel and purchased power costs calculated by the DRA in its September 1, 1988, comments on the ALJ's proposed decision, but with two modifications. First, we must recognize our conclusion in this decision to continue the suspension of Edison's AER to November 1, 1988 to mitigate the risk associated with the curtailment of Edison's natural gas supplies. Second, we are required to make minor modifications to adopted revenues in response to Edison's comments to the ALJ's proposed decision. Specifically, we have reflected in the adopted ECAC revenues Edison's requested adjustments for sales growth effects on certain writedowns and amortizations.

Prior to November 1, 1988, the net impact of this decision, relative to present rate revenues before the $200 million interim increase adopted in D.88-05-074, is therefore as follows: a $424 million increase in ECAC, a zero increase in the AER, and a $42 million decrease in ERAM. The total ECAC revenue increase resulting from this decision is $382 million.

Because we are also adjusting base rate and other rate elements to reflect increased sales, as reflected in our following discussion, the overall revenue increase is $376 million, of which

$200 million has been in place since June 1, 1988. This adopted revenue requirement will become effective October 1, 1988, at which time the net customer rates will increase by $176 million.

On November 1, 1988, the AER mechanism will be reinstated by advice letter filing. AER revenues will be $217 million, offset by a $217 million reduction to ECAC revenues. There will be no immediate effect on customer rates.

I. Revenue Allocation

In our discussion of revenue allocation in Edison's most recent general rate case, we examined the two primary methods of allocating revenue--the system average percentage change (SAPC) methodology and the equal percent of marginal cost (EPMC) methodology. In D.87-12-066 in that proceeding, we reiterated our support for marginal cost ratemaking as a means of achieving cost-based rates. To this end, we adopted an EPMC revenue allocation.

In adopting this methodology, however, we also recognized the need to mitigate negative impacts which might be caused by its use. We found that this consideration was of particular importance in the case of Edison for which an EPMC revenue allocation would result in a significant shift of revenue responsibility between Edison's customer groups. This impact was largely due to an historic allocation of Edison's revenues on bases other than EPMC which had caused Edison's rates to be quite far from EPMC. We therefore found that the move to EPMC would result in significant rate increases to the domestic class coupled with substantial rate decreases to the large power class.

With these factors in mind, in D.87-12-066 we adopted a modified version of Edison's proposal to allocate revenue on the basis of a weighted average of 2/3 SAPC and 1/3 EPMC in the first year of its three-year rate cycle. The modification of this approach involved placing a cap of 5% on increases over present rate revenues. Any remaining revenue decreases were to be spread to the large power classes in proportion to the deviation of each

class from full EPMC. We also concluded that our adoption of a 5% cap for residential customers would provide adequate relief from rate shock while still yielding significant rate reductions for large power customers. (D.87-12-066, at p. 262.)

For rate changes occurring between Edison's general rate cases, we indicated that we would "continue phasing-in to full EPMC, mitigating rate shock as required by using caps" and that we intended to achieve full EPMC revenue allocation for Edison "as soon as possible." (D.87-12-066, at p. 262.) We also stated the following:

> "For rate changes occurring between this rate case and Edison's 1989 ECAC, the rate schedule changes should consider both the system average percentage change methodology and the phased-in EPMC methodology. Edison should file proposals using both methods and indicating the utility's preferred approach. Similarly, the revenue allocation approach proposed in Edison's ECAC proceedings for the 1989 and 1990 periods should identify the methodology to be applied to Edison's intervening offset filings made after each of these proceedings if other than SAPC." (D.87-12-066 at p. 264.)

We concluded, however, that the consideration of revenue allocation issues in ECAC did not and should not include relitigation of the marginal cost structure and levels adopted in the general rate case. (Id.)

In D.88-04-026, modifying D.87-12-066, we reconfirmed our decision to require that Edison file both SAPC and phased-in EPMC proposals in its 1988 ECAC proceeding. Parties to this proceeding were also "permitted to comment on Edison's proposed revenue allocations and provide their own illustrations of an SAPC and a phased-in EPMC allocation." (D.88-04-026, at p. 8.) The testimony, however, was not to involve a re-examination of the revenue allocation policies which the Commission announced in D.87-12-066 nor to serve as a forum for the consideration of either marginal cost or rate design issues.

In our interim order in this proceeding (D.88-05-074), we adopted an SAPC revenue change of 3.7%. In doing so, however, we made clear that adoption of an SAPC revenue allocation in the interim order was "not intended to predetermine the issue of revenue allocation in this proceeding nor preclude the evidentiary showings permitted under D.87-12-066 and D.88-04-026." (D.88-05-074, at p. 24.) Rather, it had been our intent to select a revenue allocation which would minimize the possibility of any single customer class receiving an interim increase greater than its final rate change.

We also concluded that our adoption of an SAPC revenue allocation was not at odds with our stated goal of moving toward an EPMC revenue allocation for Edison. Specifically, we noted that at the time of issuance of D.87-12-066 the Commission had not considered nor anticipated the need for interim rate relief in Edison's 1988 ECAC proceeding.

Against this background, the parties presented the following revenue allocation proposals in this proceeding. These proposals also require consideration of the treatment of interruptible credits and Edison's off-peak energy charges and second block energy rate for GS-2 and PA-2. As our subsequent discussion makes clear, we must now also consider the impact of recent changes in baseline legislation and the current status of the Commission's investigation into ECAC scheduling changes.

1. Parties Positions

a. Basic Revenue Allocation Proposals

In this proceeding, Edison and TURN support a 100% SAPC revenue allocation. Edison states that its proposed SAPC revenue allocation is primarily aimed at mitigating the impact of 1988 revenue increases on residential customers. In support of its position, Edison argues that, if a phased-in EPMC revenue allocation were adopted in this proceeding, additional movement

toward EPMC would occur only eight months after the first phase-in of EPMC on January 1, 1988.

Due to the magnitude of the revenue requirement increase requested in this proceeding, Edison believes that it is more appropriate to follow an SAPC approach in this proceeding. Relying on its proposed revenue requirement, Edison states that this approach results in an 8.4% increase to residential customers. With respect to the phased-in EPMC revenue allocations proposed by other parties to this proceeding, Edison states that these proposals result in revenue changes for the domestic group 3.1% to 4.4% higher than proposed by Edison.

It is also Edison's position that D.87-12-066 limits any step toward EPMC in a single year to a 5% annual increase over the system average percentage change to any customer group. In Edison's opinion, such an approach requires consideration of both the increase to domestic rates resulting from D.87-12-066 (4.9%) as well as that adopted in this proceeding. Edison believes that it has complied with this annual cap by an overall increase to domestic rates in 1988 of approximately 17 to 18% as compared to the system increase for the same time period of 12 to 13% based on its recommended revenue requirement.

Edison rejects any allegations that its proposal results in movement away from EPMC. Edison states that, while its proposal results in customer groups moving further away from EPMC on a dollar basis, its approach in fact maintains the existing rate relationships of Edison's customer groups.

TURN's support for Edison's SAPC revenue allocation is based on several grounds. First, like Edison, TURN believes that mitigation of the impact of further rate increases in 1988 for Edison's domestic customers is critical. TURN states that, given the movement toward EPMC in the general rate case and other rate changes which could be reflected in this order, residential

customers could face an increase of as much as 10% greater than the system as a whole.

TURN believes that the Commission should proceed cautiously to avoid a high bill situation this summer as was experienced by SoCal's residential gas ratepayers during the cold snap of the past winter. Absent changes in baseline rates, TURN believes the same result could occur to Edison ratepayers in an unusually hot summer with heavy air conditioning usage. TURN also objects to movement toward EPMC today, which would impose "almost certain" rate shock, based on speculation of the "possibility" of rate shock in 1989 and 1990. (TURN Brief at p. 3.)

Additionally, TURN notes that the testimony in this proceeding reflected an increase in marginal energy cost revenues. TURN states that, if this circumstance reflects a change in marginal energy costs, the distance of each class from EPMC could also change. In TURN's opinion, this circumstance could result in Edison's EPMC target being closer than parties to this proceeding have assumed.

Except for Edison and TURN, all of the other parties to this proceeding uniformly endorsed some form of phased-in EPMC revenue allocation. These recommendations included the following:

1. DRA--DRA recommends a revenue allocation based on a weighted average of 1/3 EPMC, 2/3 SAPC.

2. CLECA--CLECA recommends the use of a 100% EPMC revenue allocation with a 5% cap on increases over the system average percentage change. Because TOU-8 subtransmission and street lighting would have received a rate reduction under its approach, CLECA also placed a floor of present rates on all classes.

3. IU--IU's approach is based on a smaller step toward EPMC in this proceeding with two larger steps in the next two ECACs. IU therefore proposes moving one-half of the way between the maintenance of existing

subsidy relationships and reduction of those subsidies by one-third.

4. FEA--FEA proposes that a 20 percent reduction of the dollar deviation from EPMC should apply to all classes, reducing the subsidy of the residential class by the large power customer class.

5. CMA--CMA supports CLECA's proposed revenue allocation.

6. CAL-SLA--CAL-SLA believes that DRA's revenue allocation proposal is consistent with D.87-12-066, but prefers a one-half EPMC revenue allocation with a 5% cap on increases above the system average percentage change. CAL-SLA opposes CLECA's proposal under which street light customers would receive no percentage increase or decrease in their rates.

While these parties' approaches to a phased-in EPMC revenue allocation vary, their grounds in support of such a revenue allocation do not. Primarily, these parties assert that an EPMC revenue allocation is consistent with current Commission policy and, despite increases over SAPC for the domestic class, must be realized in this rate case in order to achieve a full EPMC revenue allocation for Edison by 1990.

In this regard, DRA is joined by the other parties in arguing that any delay in movement toward EPMC will only mean that negatively-impacted customer classes will suffer "an even bigger jolt when rates suddenly move 50% or 100% of the way to EPMC." (DRA Opening Brief, at p. 26.) DRA believes that its approach best meets the Commission's goals of (1) achieving full EPMC by 1990, (2) moving rates toward the cost of service, and (3) minimizing negative bill impacts. DRA asserts that, in contrast, Edison's SAPC approach achieves none of these goals by postponing any further movement toward EPMC for over eighteen months (Edison's 1989 ECAC). DRA also believes its approach is

preferable to the other EPMC recommendations since a rate cap or present rate floor would distort the true EPMC relationships among ratepayer classes and slow down the progress to EPMC.

CLECA, IU, FEA, and CMA all support the Commission continuing its goal of achieving a fully cost-based revenue allocation for Edison by 1990. All of these parties agree that the movement toward EPMC in this proceeding is necessary to send proper price signals to Edison's customers and to reflect that the adoption of an EPMC-based revenue allocation in Edison's general rate case was not just a one-time occurrence.

These parties share DRA's belief that the best way to achieve an EPMC revenue allocation for Edison by 1990 is to utilize each ECAC proceeding between general rate cases. In this way, according to CLECA, rates can be moved in smaller and more regular increments toward full EPMC allocation. These parties also agree that Edison's proposal is unlikely to achieve full EPMC by 1990.

CLECA, FEA, IU, and CMA also assert that Edison's proposal is a step backward from EPMC. Specifically, each notes that Edison's proposal actually moves all customer classes farther away from EPMC in terms of the dollar distance to EPMC. In the opinion of these parties, this result will make it more difficult to achieve EPMC in 1990 and in turn will increase the rate impact on the residential class in subsequent ECACs. CLECA states that the use of SAPC to spread Edison's proposed increase could result in an increase of approximately $26 million in the dollar amount by which residential class revenues are below the residential class EPMC revenue requirement. Further, FEA argues that it is the dollar distance from cost-based rates which is what the Commission is trying to eliminate through its goal of moving rates to cost.

IU also notes that its testimony demonstrated that the residential class is the only one of Edison's major customer classes to receive a subsidy and that this subsidy ($252.7 million) continues to be largely paid by Edison's large power customers. IU

believes that these figures illustrate the need to take immediate steps toward EPMC in this rate proceeding.

CLECA and CMA dismiss Edison's and TURN's concern regarding the impact of multiple rate increases on residential customers in a short period of time. In this regard, CLECA notes that rate changes in this proceeding are unlikely before October 1, 1988. At that time, according to CLECA, the summer peak usage period would be over and any potential adverse impact on air conditioning loads caused by a rate increase would have been avoided.

This circumstance also means, according to CMA and CLECA, that the 17 to 18% increases for the residential class referenced by Edison would not be in effect for 1988, but only 3 or 4 months of 1988. CMA states that for 1988 as a whole, an additional 5% increase over SAPC for domestic rates in this case would produce an effective increase of only 6.7% above SAPC for the year as a whole. CMA bases this statement on a 5% GRC increase for 8 months coupled with a combined 10% GRC/ECAC increases for 4 months, averaging 6.7% for 12 months.

CMA is also concerned that, if no action is taken toward EPMC at this time, that the next opportunity for such movement will not be 18 months, but actually 24 months from the general rate case decision. CMA bases this argument on the statements contained in the ALJ ruling of May 26, 1988, in R.87-11-012, the Commission's rulemaking into rate case and fuel offset scheduling. In that ruling, CMA notes, the ALJ proposed a new time schedule for Edison's fuel offset proceedings which would defer the effective date of Edison's next ECAC rate change to the end of 1989. CMA states that, if the final step toward EPMC were to be made at the end of 1990, that rate change could be quite significant since it would coincide with any rate increase authorized in Edison's next general rate case.

CMA also rejects TURN's argument that the distance from EPMC will diminish simply by the Commission recognizing an increase in Edison's marginal energy costs. CMA states that such speculation ignores the potential of offsetting changes in marginal capacity costs and customer costs. Such changes, in CMA's view, would result in a reverse shift of the allocated revenue requirements share to the lower load factor domestic customers. CMA also states that, based on a larger share of total sales and changes in load patterns, updated marginal cost responsibility data show an increasing share of existing marginal costs are allocable to domestic sales.

In addition, CLECA rejects Edison's assertion that the 5% cap set forth in D.87-12-066 was meant to be applicable to all rate increases during the test year. CLECA notes that, when issuing D.87-12-066, the Commission had no way of knowing at the time what amount of revenue increase would be requested by Edison in its 1988 ECAC. In CLECA's view, it makes no sense to suggest that the Commission would foreclose its option to make additional progress toward EPMC when faced with a $400 million increase.

In support of CLECA's revenue allocation, CMA asserts that DRA's approach would perpetuate the existing disproportionate degrees to which other classes support the domestic subsidy. CMA similarly found that FEA's and IU's approach did not result in a significant enough change and retained the existing wide range of subsidization intact.

CAL-SLA joins those parties supporting a phased-in EPMC revenue allocation in this proceeding. CAL-SLA states that, because the street lighting customer's rates are presently the furthest from marginal costs, an EPMC-based revenue allocation in this proceeding is critical. CAL-SLA opposes the proposal of CLECA under which street light customers would receive no percentage increase or decrease and therefore no change in the subsidization by street lighting.

CAL-SLA also states that Edison has erred by not excluding facilities charges from the revenue allocation process. CAL-SLA disagrees with Edison's statements that facilities charges should be excluded only when an EPMC revenue allocation process is imposed. It is CAL-SLA's opinion that the Commission has made no distinction between revenue allocation methods as far as the exclusion of facilities charges. (CAL-SLA citing D.87-12-066, Conclusion of Law 137.) CAL-SLA further notes that facilities charges were excluded from the revenue allocation adopted by the Commission in the interim decision, in this proceeding. (D.88-05-074 at pages 23 and 23a.)

b. **Issues Related to Interruptible Credits and Off-Peak Energy Charge**

The two other revenue allocation issues addressed by the parties included (1) the treatment of interruptible credits in the revenue allocation process and (2) the level of the off-peak energy rate for rate schedule TOU-8 and the second block energy rate in Rate Schedules GS-2 and PA-2. The first issue surfaced as a result of the revenue allocations proposed by FEA and IU, while the second issue is a result of different interpretations of the Commission's rate design adopted in D.87-12-066.

With respect to the treatment of interruptible credits in the revenue allocation process, both FEA and IU have proposed EPMC-based revenue allocations in which interruptible credits are excluded from that process. Edison asks the Commission to reject this approach asserting that only street and area lighting facilities charges were authorized by D.87-12-066 to be excluded from the revenue allocation process. Further, Edison states that consideration of this exclusion is beyond the scope of this proceeding. Specifically, Edison notes that D.87-12-066, as reaffirmed in D.88-04-026, provided that marginal cost revenue responsibility levels should not be relitigated in this ECAC proceeding.

In response to Edison's criticism, IU asserts that its treatment of interruptible credits is not a recalculation of marginal cost revenue responsibility. IU states that its marginal cost revenue responsibility figures are no different than the figures used by other parties in their revenue allocation proposals. According to IU, its interruptible credit adjustments simply involve splitting out "below the line" the interruptible credit portion of large power revenues. IU states that this adjustment is necessary to ensure that large power revenues are shown exclusive of interruptible credits to allow for comparison of firm costs and firm revenues.

FEA concurs with IU that the exclusion of interruptible credits is necessary to overcome Edison's assumption, in determining the marginal cost share for the TOU-8 class, that all customers take firm service. By making this assumption, FEA states that Edison overstates TOU-8 cost responsibility. FEA therefore recommends allocating firm revenue responsibility based on EPMC to all classes and allocating the interruptible credits within the TOU-8 class on a basis parallel to the spread of interruptible credits in the calculation of sales revenue. FEA states that its proposal does not change the marginal costs as established in D.87-12-066, but merely treats interruptible credits in a different fashion.

In this proceeding, DRA proposes to increase the TOU-8 and TOU-GS off-peak energy rates from 5 cents/kWh to 5.2 cents/kWh based on its Class Equal Percent Change (CEPC) rate design. DRA did not offer a PA-2 rate design, but stated that it should also reflect a CEPC rate design. (Tr. at p. 664.)

In support of its position, DRA argues that if off-peak rates are held constant as on- and mid-peak rates rise, the potential for economic bypass on Edison's system increases. In DRA's opinion, the failure to increase off-peak rates also increases the potential for rate shock in the mid- and on-peak

rates. DRA therefore believes that holding the off-peak rate constant at 5 cents/kWh would unduly distort the price relationships established in the general rate case.

With respect to the off-peak energy rate, Edison asserts that this rate for the TOU rate schedules and the second block for GS-2 and PA-2 was set in D.87-12-066 at five cents per kilowatt-hour to ensure a stable rate level. In that decision, Edison notes that the Commission specifically did not employ a percentage relationship between the mid-peak and on-peak levels as assumed by DRA nor did it utilize DRA's proposed EPMC relationship for setting the off-peak rate level. Edison therefore objects to DRA's proposal to increase off-peak energy charges in this proceeding. While D.88-05-074 applied DRA's CEPC rate design to off-peak rates, Edison believes that this action was taken in the mistaken belief that it was consistent with the general rate case decision.

CMA supports Edison's proposed 5 cent/kWh off-peak TOU-8 energy rate. CMA states that as the 5 cent/kWh rate was chosen to provide a stable off-peak rate and to mitigate billing impacts from rate restructuring, it deserves to be maintained at this time without increase. In fact, CMA argues that, examined on a cost basis, the off-peak rate should in fact be lower than 5 cents/kWh. Having been set at higher than EPMC level for non-cost reasons, CMA urges that the rate remain at that level.

CMA also notes that DRA's assertion regarding the need to increase off-peak energy rates to avoid excessive increases to mid- and on-peak energy rates is only valid with respect to Edison's SAPC revenue allocation. CMA states that DRA did not demonstrate that these disproportionate increases occur under any other proposed revenue allocation.

2. Discussion

Since the issuance of our decisions in Edison's most recent general rate case and even the interim order in this proceeding, several events have occurred which directly impact our

determination of the appropriate revenue allocation to be adopted in this proceeding. Specifically, we must consider (1) the significant revenue increase which will result from this decision, (2) the enactment of Senate Bill (SB) 987 amending the baseline statute (Section 739 of the Public Utilities Code) and the implementation of that legislation by the Commission (I.88-07-009), and (3) finally, the Commission's rulemaking to revise the general rate case and fuel offset time schedules (R.87-11-012).

This decision results in authorizing a $382 million increase in Edison's ECAC revenue requirement. This sum is, of course, substantially less than the original $628 million requested by Edison in this proceeding, but is still significantly more than the $32.7 million decrease authorized in the general rate case. Such a revenue change will obviously have a significant impact on many of Edison's customers.

As explained earlier in this section, the Commission in adopting an EPMC-based revenue allocation for Edison in D.87-12-066 was faced with a significant shift of the revenue responsibilities of its customer classes. We concluded, however, that it was our goal to continue to move toward and achieve a revenue allocation based on "full EPMC" "as soon as possible." (D.87-12-066, at p. 262.)

The issue directly raised by Edison's and TURN's support of an SAPC allocation for this ECAC proceeding is how fast and how disruptive does this transition to EPMC needs to be. Edison and TURN express their concern with the rate shock to the domestic group which would result from a 4.9% increase from the general rate case being quickly followed by a potential 12 or 13% increase in this proceeding based on capped EPMC revenue allocation and Edison's proposed revenue requirement. Both seem to infer that delaying further movement to EPMC until Edison's 1989 ECAC will not have any demonstrably negative impact on that process.

While we agree that Edison's domestic customers will face multiple rate increases in a single year, we believe that the "shock" of those increases has been mitigated by several factors. These factors include: (1) the timing of this rate increase in terms of Edison's last general rate case, (2) the ALJ's proposed changes to Edison's ECAC schedule, and (3) the enactment of SB 987. As certain of the interested parties have pointed out, the rate changes resulting from this ECAC are unlikely to occur before October 1, 1988. This date is nine months after the rate changes in the general rate case and follows the summer peak period. Additionally, by issuing an interim order in this proceeding authorizing a 3.7% rate increase for all customer groups, Edison's domestic ratepayers will see a more gradual increase in their rates, rather than one significant rate increase.

With respect to planned changes in Edison's ECAC revision dates, we note, as did CMA, the issuance of an ALJ ruling in R.87-11-012 on May 26, 1988. In that ruling, the ALJ considered a "consensus" document submitted by the major parties to the rulemaking proposing schedules for the utilities' fuel offset proceedings. Additionally, the ALJ stated his agreement with the consensus proposal with the exception of the schedule for Edison.

Because of simultaneous hearings for Edison and SoCal resulting from that schedule, the ALJ proposed having "Edison's ECAC lag SoCal's ACAP by three months." The proposal had been for Edison's rates to become effective in late September; the change offered by the ALJ would result in this date being postponed to December. This proposal has yet to be adopted by the Commission.

Under these circumstances, CMA has correctly pointed out the potential for a rate change in Edison's 1989 ECAC not occurring until December, 1989, almost two years after the general rate case decision. Although we are concerned with "rate shock" to specific customer groups, it is still our intention to move toward EPMC and to achieve full EPMC for Edison by its next general rate case.

Given the possibility of a change in the proposed effective date in Edison's 1989 ECAC to December 1989, achieving full EPMC seems unlikely if some progress is not made in this proceeding. Alternatively, the impact of multiple rate increases at the time of Edison's next general rate case and its 1990 ECAC could impede further movement to EPMC at that time.

TURN has also expressed concern regarding the impact of an EPMC revenue allocation on residential customers using quantities above the baseline amounts. We believe that this concern has been somewhat mitigated by the enactment of SB 987 and our implementation of that legislation in I.88-07-009.

Specifically, the purpose of I.88-07-009 is to provide for the immediate realignment of baseline and nonbaseline residential rates by the start of the 1988-89 heating season or November 1, 1988, consistent with SB 987. Today the Commission issues its first decision in that investigation. In that order, we adopt the stipulation of Edison, DRA, and TURN to realign Edison's baseline and Tier II residential rates consistent with SB 987. Specifically, this stipulation provides that Edison's Tier II rate be reduced with the resulting shortfall in revenue offset by a modest increase in the baseline rate. Under this stipulation, Edison's baseline rate will rise from 85% to 87% of the system average rate.

Consistent with this order and SB 987, it is reasonable to direct Edison to make the rate changes required by that decision and reflected in Appendix D of this order effective concurrently with the ECAC revenue increase authorized in this decision. To ensure a rate change that coincides with the seasonal rate changes experienced by most of Edison's customers and to comply with the November 1, 1988, implementation date of SB 987, the rates adopted in this proceeding will be made effective October 1, 1988.

Under these circumstances, we believe that it is appropriate to take a further step toward a full EPMC revenue

allocation for Edison in this proceeding. D.87-12-066 does not prohibit such a step being taken in this ECAC and, despite other parties' contentions to the contrary, does not limit the percentage increase over the system average percentage change which can occur.

Specifically, Edison has argued that the Commission's 5% cap was an "annual" cap on rate increases. In fact, we find that D.87-12-066 not only did not provide for such a limitation, but makes clear that any revenue allocation adopted by the Commission in subsequent offset proceedings be determined by the circumstances existing at the time of the offset. (D.87-12-066, at p. 262.) In that decision, we also directed Edison and other parties to file SAPC and phased-in EPMC proposals without any limitation on the nature of their phase-in proposals.

Edison may have reached its conclusion based on references in D.87-12-066 to revenue allocation changes in the two years <u>following</u> the test year. These statements would seem to imply that no revenue allocation changes were intended during the test year (1988).

While this result may have been one for which the Commission had hoped, this expectation is not a reasonable one given the current circumstances of a significant rate increase and changes in the timing of intervening rate changes. Additionally, the fact that the Commission in part foresaw the need to reevaluate revenue allocation is reflected in our providing for consideration of revenue allocation in this proceeding in both D.87-12-066 and D.88-04-026.

We note TURN's arguments regarding changes to marginal energy cost revenue responsibility and speculation regarding future rate increases. In answer to these points, we again note that the issue of marginal cost structure was not to be considered in this proceeding. Even if we had considered new marginal energy costs, it is unlikely that these costs would have changed

marginal cost revenue responsibility sufficiently to change the percentage distance of residential rates from EPMC.

With respect to future rate increases, although they may be less than this request, the magnitude of rate increase adopted in this proceeding has the direct effect, as pointed out by many parties, of increasing the discrepancy in actual dollar terms between the revenue responsibilities of the large power and residential classes. We believe that some movement toward EPMC in this proceeding is preferable to permitting that situation to deteriorate.

In reviewing the various proposals of the parties, we therefore believe that a reasonable basis upon which to achieve further movement toward EPMC and mitigate any negative rate impact is a modified version of DRA's methodology. DRA's approach requires a weighted average of 1/3 EPMC and 2/3 SAPC. We will adopt this basic approach, but modify it to add a 2.5% cap over the system average percentage change for all customer groups. No floors on rate reductions, however, will be required. We believe that this approach has the positive effect of achieving some movement toward EPMC in this proceeding, mitigating rate shock to the domestic customer group, and providing a balanced treatment of all of Edison's customer classes.

Our adopted revenue allocation is shown on the following table. This allocation is based on Edison's total adopted revenue requirement as of October 1, 1988. Details are shown in Appendices B and C. This table also illustrates some of the proposed revenue allocation methodologies.

A.88-02-016 ALT/SWN/flo
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SOUTHERN CALIFORNIA EDISON COMPANY ECAC
ADOPTED REVENUE ALLOCATION 1/
EFFECTIVE OCTOBER 1, 1988

CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV PRIOR TO INTERIM 3/ ($000's)	PRESENT RATE REV 3/ 4/ ($000's)	TOTAL MC REVS 5/ ($000's)	FULL EPMC ($000's)	(%) INC.	(EDISON) SAPC ($000's)	(%) INC.	(DRA) 2/3 SAPC 1/3 EPMC ($000's)	(%) INC.	EPMC CAPPED AT 5% OVER SAPC ($000's)	(%) INC.	EPMC CAPPED AT 2.5% OVER SAPC ($000's)	(%) INC.	ADOPTED CHANGES: 2/3 SAPC 1/3 EPMC 2.5% CAP OVER SAPC 6/ ($000's)	(%) TOTAL INC.	(%) INC. OVER INTERIM	AVERAGE RATE ($/KWH)
DOMESTIC	20,162	1,726,096	1,789,992	1,611,300	2,115,733	22.6	1,874,522	8.6	1,954,926	13.3	1,960,813	13.6	1,917,667	11.1	1,917,667	11.1	7.1	0.095
SM/MED POWER																		
GS-1	4,187	434,915	451,017	363,200	476,842	9.6	472,319	8.6	473,826	8.9	494,065	13.6	483,192	11.1	478,816	10.1	6.2	0.114
GS-2	18,084	1,560,580	1,618,357	1,225,500	1,608,977	3.1	1,694,791	8.6	1,666,187	6.8	1,676,641	7.4	1,704,737	9.2	1,682,295	7.8	4.0	0.093
LARGE POWER																		
TOU-8:2ND	6,756	540,725	560,745	416,900	547,344	1.2	587,229	8.6	573,934	6.1	570,362	5.5	579,920	7.2	579,337	7.1	3.3	0.086
TOU-8:PRI	10,413	746,462	774,099	558,700	733,512	(1.7)	810,660	8.6	784,944	5.2	764,359	2.4	777,168	4.1	792,014	6.1	2.3	0.076
TOU-8:SUB	3,189	185,051	191,902	133,200	174,877	(5.5)	200,966	8.6	192,270	3.9	182,231	(1.5)	185,285	0.1	193,900	4.8	1.0	0.061
AGRICULTURE	2,073	172,010	178,376	139,600	183,345	6.6	186,798	8.6	185,647	7.9	191,053	11.1	191,097	11.1	187,528	9.0	5.1	0.090
STREETLIGHTING	475	70,321	71,671	20,000	60,113	(14.5)	73,457	4.5	69,009	(1.9)	61,217	(12.9)	61,676	(12.3)	69,186	(1.6)	(3.3)	0.146
TOTAL	65,338	5,436,160	5,636,159	4,468,400	5,900,742	8.5	5,900,742	8.5	5,900,742	8.5	5,900,742	8.5	5,900,742	8.5	5,900,742	8.5	4.7	0.090

1/ Although facilities charges and optional TOU meter charges have been excluded from the revenue allocation process, these amounts have been added to the figures in this table in order to obtain the correct percentage increases and average rate calculations. Facilities charges and TOU meter charges are expressed in thousands for the following classes: $273.6 for domestic; $30.6 for GS-2; $65.3 for agriculture; $33,855.2 for streetlighting.

2/ ECAC sales figures have not been adjusted for employee discounts; fringe and Sequoia sales have been excluded.

3/ Present rate revenues include optional TOU meter charges for test year 1988 per SCE general rate case decision D.87-12-066, and differ slightly from Interim D.88-05-074. Additional revenues for optional TOU meters will be reflected in attrition per D.87-12-066. Present rate revenues are adjusted for the Large Power class to reflect the difference between actual interruptible credits and credits allocated on an EPMC basis.

4/ Interim Decision 88-05-074 issued May 25, 1988.

5/ Based on marginal costs from SCE general rate case D.87-12-066. Marginal cost revenue responsibility has been updated for ECAC forecast sales, demand and customers.

6/ Interruptible credits are computed on an EPMC basis, based on D.87-12-066 as modified. Revenue deficiency from capping is spread to other classes on a 2/3 SAPC, 1/3 EPMC basis.

This table reflects authorization of expense revisions for only the ECAC/AER/ERAM portion of Edison's revenue requirement and adoption of a new revenue allocation. Under these circumstances, we have two choices for the treatment of base rates: (1) to leave base rates unchanged resulting in Edison's ERAM account becoming susceptible to overcollection because the sales forecast adopted in this proceeding exceeds the sales used in setting the current base rates, or (2) to leave base rate revenue requirement unchanged, except for authorized revenue changes since the interim decision, and revise base rates to reflect the new sales level.

In order to minimize fluctuations in the ERAM account balance, we find that it is reasonable to adopt the second of these options. We have recently adopted this approach in setting ECAC/AER/ERAM rates for PG&E in D.87-12-068. We further note that this rate adjustment has no impact on authorized base rate revenue requirement.

Although Edison's Major Additions Adjustment Clause (MAAC) and Conservation and Load Management Adjustment Clause (CLMAC) rates are not constructed in exactly the same way as base rates, we will also adjust those two rates for the new sales forecast to be consistent with our approach to base rates. The amortization rates included in ECAC for the Chevron Settlement, the Uranium Contract Termination, the LSFO Inventory Writedown will also be adjusted to reflect the new sales forecast adopted in this decision. The revenue impacts of this decision are minimal (see footnotes 4 and 5, Appendix C). By following this approach, all of Edison's rate elements will be determined using the most recently adopted sales forecast.

Finally, we address the treatment of interruptible credits and streetlight facilities charges in the revenue allocation process and the determination of Edison's off-peak energy charge and a second block energy rate for GS-2 and PA-2. We

find that D.87-12-066 makes clear that "[s]treetlight energy charges, but not facilities charges associated with an end-use, should be included in the revenue allocation process." (D.87-12-066, at p. 442.) We did not intend, contrary to Edison's conclusion, to limit this exclusion of facilities charges to EPMC-based revenue allocations. We therefore share CAL-SLA's conclusion that the exclusion of streetlight facilities charges is equally appropriate for both SAPC and EPMC revenue allocations.

We do not believe, however, that this proceeding is the appropriate forum for considering an alternative method of treating interruptible credits in the revenue allocation process. Consideration of revenue allocation issues was limited to SAPC or phased-in EPMC proposals. In all other ways, our treatment of marginal costs or a customer's usage patterns was to remain constant with our findings in D.87-12-066. We therefore will not adopt the alternative approach taken by IU and FEA with respect to interruptible credits, but suggest that the parties renew such suggestions in Edison's next general rate case.

With respect to Edison's off-peak energy charge, in D.87-12-066 we rejected DRA's proposal to set the off-peak energy rate at the full EPMC level. Instead, we adopted Edison's proposed 5 cent/kWh off-peak energy charge "to ensure consistency between the TOU-8 and TOU-GS schedules and to mitigate any adverse effect which might result from customers having to change schedules." (D.87-12-066, at p. 324.)

The result of this finding was effectively to insulate the off-peak energy charge from revenue increase changes which would require other charges to be increased toward their EPMC relationships. Our change to this rate resulting from the interim order in this proceeding (D.88-05-074) was, as Edison observes, inadvertent.

We therefore find that the off-peak energy charge contained in Edison's time of use schedules listed in Appendix D to

this decision and the second block energy rate for Rate Schedules GS-2 and PA-2 should be returned to the 5-cent/kWh level, but all other charges should be changed in accordance with DRA's proposed CEPC rate design.[1] As we found in D.88-05-074, this rate design proposed by DRA is consistent with D.87-12-066 and D.88-04-026.

Findings of Fact

1. Because Edison has had a full and fair opportunity to present testimony on the current ECAC forecast period and the Commission in its emergency order in I.88-08-052 has addressed gas supply concerns raised by Edison, it is unnecessary and unreasonable to set aside submission and reopen hearings in the forecast phase based on those concerns.

2. It is reasonable to afford relief to Edison due to the gas curtailment identified by the Commission in I.88-08-052 as a result of the action taken by this Commission and the unique nature of the event.

3. To minimize Edison's economic risk due to the gas curtailment referenced in the finding above, it is reasonable to continue the suspension of Edison's AER until the end of the Forecast Period.

4. It is reasonable to suspend Edison's AER only when and if circumstances warranting such action actually exist.

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1 Our application of DRA's CEPC rate design in the interim order D.88-05-074 effectively requires a reduction in the off-peak energy charge adopted in that order to the 5-cent/kWh level.

5. Substantial and adequate rate relief based on the adopted forecasts in this proceeding has been provided by this order, and no additional increase related to recorded information obtained after the submission of this proceeding and pertaining to the forecast period is therefore required.

6. Edison's current ECAC marks the beginning of the regular annual updating in ECAC of key components in the calculation of prices paid for power sold to the utility by qualifying facilities.

7. Because the ECAC proceeding is intended to reflect the most up-to-date data in any adopted forecast expense or IER, it was reasonable for Edison and DRA to update their recommendations in this proceeding.

8. It is the Commission's goal to develop both a utility's rates and QF prices on a consistent basis.

9. There is no evidence in this proceeding that the ELFIN production cost computer model produces unreasonable forecast results or results substantially at odds with the FPP spreadsheet program.

10. The use of a production cost model to forecast both revenue requirements and components of variable QF payments best achieves the Commission's regulatory goals, reflects the growing reliance on computer modeling in ratemaking, and ensures consistency in establishing both utility rates and QF payments.

11. Based on the preceding findings, it is reasonable to adopt DRA's recommendation to use ELFIN to develop both Edison's revenue requirement and its IER.

12. Due to the adoption of most of DRA's recommended forecast assumptions, it was necessary only for DRA to "re-run" its ELFIN computer model for revenue requirements purposes during the comment phase.

13. Because the ALJ's proposed decision did not uniformly adopt the assumptions of any single party with respect to the IER

calculation, it was necessary for the parties to "re-run" ELFIN during the comment period to provide their final recommendations.

14. It is reasonable to consider the revised IER and revenue requirement recommendations presented during the comment period as late-filed exhibits and to have required the parties offering those recommendations to serve each other with all supporting work papers at the same time their comments are filed.

15. The adopted procedure for considering revised IER and revenue requirement recommendations during the comment period, necessitated by time constraints in this proceeding, is appropriate given that all parties have used the same model and have had an equal opportunity through many days of workshops and hearing to discuss and cross-examine each party's use of ELFIN.

16. In their ELFIN runs performed during the comment period following the issuance of the ALJ proposed decision in this proceeding, all of the parties correctly applied the stipulated ERI value of 0.43 for all 12 months of the forecast period.

17. It is reasonable to adopt the agreement reached by Edison and DRA on the issues of sales forecast, Edison hydro generation, nuclear generation and expense, and the estimated ECAC and ERAM account balances as each is based on the most recent data and surveys.

18. Inconsistencies in Edison's approach in forecasting its gas price, as well as an exaggerated response to seasonal curtailments, undermine the reliability of Edison's forecast.

19. Because DRA considered all of the elements necessary to provide a reasonable level of gas generation expense and developed a reasonable gas price forecast, it is reasonable to adopt DRA's forecast of this expense item.

20. It is the Commission's intention to maintain consistency in the forecasts of both gas and oil expenses with respect to the components which these forecasts share in common.

21. DRA has made a reasonable forecast, based on the record in this case, concerning the level of gas curtailment which Edison can anticipate this winter.

22. It is reasonable to adopt DRA's forecast 15-day gas curtailment period, reflected in both its gas and oil generation expense forecasts, given the provisions we are making for continuing suspension of the AER.

23. DRA's well-supported independent forecast of LSFO oil prices is reasonable.

24. Having found reasonable DRA's estimates of the two components determining oil generation expense, it is reasonable to adopt DRA's forecast for this expense item of $24.8 million for the forecast period.

25. DRA's and Edison's agreement on the quantity of QF power and the capacity factors projected for the four large QF projects is a reasonable compromise of the forecasts presented and should be adopted.

26. DRA has established and Edison has recognized the need to develop better records reflecting the status of each of Edison's QF contracts and to provide this data in a timely fashion to DRA.

27. Given the adoption of DRA's gas price forecast and approval of DRA's use of ELFIN to determine revenue requirement, the final firm purchase power expense level is likely to be closer to that forecasted by DRA than by Edison.

28. During the comment period, DRA was required to re-examine its firm purchase power forecast to determine the change in revenue impact, if any, caused by any change to its recommended IER resulting from the assumptions adopted in this decision.

29. CCC/CSC failed to adequately demonstrate that a seven-month period of zero-availability of PNW economy energy power is likely to occur during the forecast period.

30. The three-month period of zero-availability of economy energy power projected by DRA and Edison is a reasonable forecast of the future availability of PNW power.

31. The differences between Edison's and DRA's non-firm power purchases and expense are largely attributable to the differences in the parties' gas price forecasts and DRA's use of ELFIN to determine Edison's revenue requirement.

32. Given the adoption of DRA's forecast gas price, PNW economy energy availability, and use of the ELFIN model for determining Edison's revenue requirement, it is reasonable to adopt DRA's forecast of PNW economy energy availability and expense.

33. Based on the adoption of DRA's gas price forecast and its use of the ELFIN model to develop Edison's revenue requirement, it is reasonable to adopt DRA's forecast of PSW economy energy availability and expense.

34. While there is insufficient support in this record to adopt a ceiling on PSW economy energy availability, the parties can continue to explore the efficacy of "hardwiring" the ELFIN model in the IER workshops held in future ECACs.

35. The difference between Edison's and DRA's coal generation expense forecasts is attributable to different gas prices and ELFIN dispatch of Mohave.

36. Given the adoption of DRA's forecast gas price and its use of ELFIN to determine Edison's revenue requirement, it is reasonable to adopt DRA's forecast of coal generation and expense.

37. DRA's and Edison's agreement on the coal inventory level and carrying costs is reasonable.

38. There is insufficient evidence in this record to support the changes in circumstance which Edison asserts require a fuel oil inventory level greater than the level adopted in its 1987 ECAC.

39. It is reasonable to adopt DRA's forecast of a 4.4 million barrel fuel oil inventory which maintains the inventory level adopted for Edison in D.87-11-013.

40. The difference between DRA's and Edison's fuel oil inventory carrying costs is attributable to differences in their forecast fuel oil inventory levels.

41. Having adopted DRA's fuel oil inventory level for the 1988 forecast period, it is reasonable to adopt DRA's fuel oil inventory carrying costs.

42. Consistent with D.87-11-013, it is reasonable to adopt the same ratemaking treatment for fuel oil inventory carrying costs, variations from adopted levels, and gains or losses as adopted in that decision.

43. The fact that different fuel oil inventory carrying cost procedures might be adopted for PG&E does not necessarily warrant or require their mandatory application to Edison.

44. In D.87-12-066, the Commission transferred the rate recovery of coal and nuclear inventory carrying costs from base rates to ECAC rates effective January 1, 1988, and directed that they be included 100 percent in the ECAC balancing account.

45. In D.87-12-069 in SDG&E's 1987 ECAC, the Commission declined to adopt DRA's "lump sum" approach for fuel oil inventory carrying costs.

46. Given the Commission's continuation of a memorandum account for fuel oil inventory carrying costs, it is reasonable to to create a similar account for nuclear fuel and coal inventory carrying costs for later potential recovery through ECAC and to direct Edison to include 100% of its adopted nuclear fuel and coal inventory carrying costs in ECAC.

47. It is reasonable to allow Edison to finance its nuclear fuel inventory carrying costs based on an interest rate which is a blend of short- and intermediate-term debt rates.

48. It is reasonable to adopt DRA's recommended methodology for calculating franchise fees and uncollectible accounts expense and resale accounts allocation based on the adoption of DRA's other forecast recommendations.

49. The workshops ordered by D.87-12-066 and held before the hearings in this forecast phase have greatly enhanced consideration of the many complex issues now included in ECAC and should be continued.

50. Because the parties have had the opportunity to review each other's recommendations, it is reasonable to adopt the parties' stipulation of an ERI value of 0.43 for Edison's forecast phase.

51. The procedures followed in this proceeding, including the IER workshops, the forecast phase hearings, and presentation during the comment phase of ELFIN model runs based on our adopted forecasts and assumptions related to Edison's revenue requirement and IER, have provided all parties a full and fair opportunity to litigate the issues in this proceedings.

52. The record in this proceeding supports the adoption of values, as opposed to methodologies, for the assumptions in dispute and the Commission's consideration during the comment phase of IER recommendations based on those values.

53. There is insufficient evidence in this record that any of the parties to this proceeding used the ELFIN model in an inappropriate way or applied poor judgment in reviewing ELFIN results for reasonableness.

54. Sole reliance on the past, and specifically, a single recorded IER, is not appropriate in any forecasting effort.

55. Factual matter or expert opinion upon which a party intends the Commission to rely as support for or a challenge to a particular position is evidentiary in nature and should not be presented in a post-hearing brief.

56. The revision of IER recommendations during the comment period is distinguishable from CCC/CSC's inclusion of sensitivity results in its brief for the following reasons: (1) each party had the same opportunity to present their recommendations at the same time and under the same circumstances, (2) each of these

submissions was accorded the same status (late-filed exhibit), (3) the same assumptions were used, (4) supporting work papers were served on each party performing a model run, and (5) each party had the opportunity to address the revised recommendations in their comment responses.

57. A "substitute unit," as referenced in D.88-03-079, is a "new" resource added in response to the absence of short-run QFs and not an "existing" unit returned from cold standby to fill an intermittent loss of capacity.

58. It is reasonable for those performing a "QFs Out" run to return cold standby units to service in response to a shortage in capacity.

59. To mirror actual system operations, the standby units reflected in a "QFs Out" run should be those which should actually be used to respond to intermittent capacity shortfalls, and their inclusion in this run should be limited to the actual period of time in which the capacity shortage is forecast.

60. CCC/CSC has demonstrated the reasonableness of including Etiwanda 1 and 2 and San Bernardino 1 and 2 as standby units in the "QFs Out" run for the two-month period in which a capacity shortage is forecast.

61. In forecasting Edison's system operations, it is reasonable to reflect the "probability" of forced outages in ELFIN runs and, in turn, to de-rate capacity for forced outages as well as maintenance.

62. Given the time constraints and procedures adopted for this ECAC, it is not reasonable to adopt a methodology for determining and adjustment the commit target variable.

63. The record, which includes reasonable approaches to determining commit target variables, is sufficient to permit the Commission to adopt specific commit target values in this proceeding and, with the adoption of DRA's resource mix

assumptions, supports the adoption of DRA's commit target values for the forecast period.

64. For consistency between utilities with standard offer contracts, it is reasonable to apply to Edison the same approach adopted for PG&E in D.86-10-045 for determining fixed gas costs.

65. It is reasonable to reflect avoided gas costs in QF energy payments consistent with the findings of D.88-07-024.

66. Having applied the proper assumptions, forecasts, and methodologies, it is reasonable to adopt DRA's final revenue requirement and IER proposals contained in its comments to the ALJ's proposed decision.

67. In Edison's recent general rate case, the Commission has indicated its intent to move toward an EPMC revenue allocation for Edison "as soon as possible." (D.87-12-066, at p. 262.)

68. Recent decisions make clear the Commission's intent to consider a further phase-in of an EPMC revenue allocation for Edison in this proceeding, as well as proposals for an SAPC revenue allocation.

69. Although Edison's domestic customers will face multiple rate increases this year, the "shock" of these increases being allocated on a phased-in EPMC basis has been mitigated by the following: (1) the timing of this rate increase in terms of Edison's last general rate case, (2) the ALJ's proposed changes in Edison's ECAC scheduling, and (3) the enactment of SB 987.

70. The circumstances listed in the above finding, which also suggest the timeliness of a further movement toward EPMC in this proceeding, have produced the following results: (1) the rate change adopted in this decision will follow the general rate case by nine months and will not include the summer peak period for Edison's nondomestic service customers and some of its domestic customers, (2) the issuance of an interim order in this proceeding will result in more gradual increases in domestic rates during this year, (3) the ALJ's proposed schedule for Edison's 1989 ECAC could

result in a rate change in the Edison's next ECAC at least 24 months after issuance of the general rate case, and (4) changes in domestic rates resulting from the Commission's implementation of SB 987 have resulted in providing some rate relief to Edison's Tier II residential customers.

71. The magnitude of rate increase adopted in this proceeding has the direct effect of increasing the discrepancy in actual dollar terms between the revenue responsibilities of the large power and residential classes.

72. Based on the preceding findings, it is appropriate to take a further step toward a full EPMC revenue allocation for Edison in this proceeding.

73. D.87-12-066 does not prohibit a further step toward EPMC being taken in this proceeding nor does it limit the percentage increase over the system average percentage change which can occur.

74. A reasonable basis upon which to achieve further movement toward EPMC, mitigate rate shock to the domestic customer group, and provide a balanced treatment of all of Edison's customer classes is to adopt a modified version of DRA's proposed revenue allocation.

75. It is reasonable to adopt a revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all customer groups, but with no floor on rate reductions.

76. It is reasonable to make the rate change authorized in this decision coincide, to the extent possible, with the change from the summer to winter residential baseline period and realignment of baseline rates resulting from implementation of SB 987.

77. In order to minimize fluctuations in the ERAM account balance, it is reasonable to leave base rate revenue requirement unchanged, except for authorized revenue changes since the interim decision, and revise base rates to reflect the new sales level.

78. It is reasonable to adjust Edison's MAAC and CLMAC rates for the new sales forecast to be consistent with the adopted approach for adjusting base rates.

79. It is reasonable to adjust certain rate sub-elements of Edison's ECAC rate (i.e., Chevron Settlement Rate, Uranium Contract Termination Rate, LSFO Inventory Writedown Rate, and Distillate Inventory Writedown Rate) for the new sales forecast so that all of Edison's rate elements will be determined using the most recently adopted sales forecast.

80. In D.87-12-066, the Commission did not intend to limit the exclusion of street light facilities charges from the revenue allocation process to EPMC-based revenue allocations.

81. It is equally appropriate to exclude street light facilities charges from both SAPC and EPMC revenue allocations.

82. This proceeding is not the appropriate forum for changing the treatment of interruptible credits in the revenue allocation process from that followed in D.87-12-066.

83. In D.87-12-066, the Commission intended to insulate the off-peak energy charge included in Edison's time-of-use schedules from revenue increase changes which would require other charges to be increased toward their EPMC relationships.

84. The off-peak energy charge contained in Edison's time-of-use schedules listed in Appendix D to this decision and the second block energy rate for Rate Schedules GS-2 and PA-2 should be returned to the 5-cent/kWh level approved in D.87-12-066 following their inadvertent increase in D.88-05-074.

85. Except for the off-peak energy charges and the second block energy charges referenced above, consistent with D.87-12-066 and D.88-04-027, all other charges should be changed in accordance with DRA's CEPC rate design.

Conclusions of Law

1. Edison's petition to set aside submission and reopen hearings in the forecast phase should be denied.

2. The temporary suspension of Edison's AER should be continued to the end of this ECAC's Forecast Period.

3. Any subsequent suspension of Edison's AER should be authorized only when and if circumstances warranting such action actually exist.

4. In this proceeding, it is reasonable to adopt DRA's recommendation to use the ELFIN production cost model to develop both Edison's revenue requirement and its IER.

5. During the comment period following issuance of the ALJ's proposed decision, DRA properly "re-ran" its ELFIN model based on the adopted forecast expenses, resource mix, and IER assumptions to produce the final revenue requirement adopted in this proceeding.

6. During the comment period following issuance of the ALJ's proposed decision, Edison, DRA, and CCC/CSC appropriately "re-ran" the ELFIN model based on the input assumptions and modeling conventions adopted in this decision to produce their final IER recommendations.

7. The revised revenue requirement and IER recommendations presented during the comment period in this proceeding should be considered late-filed exhibits and should be supported by work papers served on all parties making ELFIN runs during the comment period.

8. The agreement reached by Edison and DRA on the issues of sales forecast, Edison hydro generation, nuclear generation and expense, and the estimated ECAC and ERAM account balances should be adopted.

9. DRA's gas price forecast is reasonable and should be adopted.

10. DRA's gas generation expense forecast of $613.25 million is reasonable and should be adopted.

11. Consistency should be maintained in the forecasts of both gas and oil expenses with respect to the components which these forecasts share in common.

12. DRA's oil general expense forecast of $24.8 million is reasonable and should be adopted.

13. DRA's and Edison's agreement on the quantity of QF power and the capacity factors projected for the four large QF projects is reasonable and should be adopted.

14. DRA's forecast of PNW economy energy availability and expense is reasonable and should be adopted.

15. DRA's forecast of PSW economy energy availability and expense is reasonable and should be adopted.

16. DRA's forecast of coal generation and expense is reasonable and should be adopted.

17. DRA's and Edison's agreement on the coal inventory level and carry costs is reasonable and should be adopted.

18. DRA's forecast of a 4.4 million barrel fuel oil inventory is reasonable and should be adopted.

19. DRA's forecast of fuel oil inventory carrying costs is reasonable and should be adopted.

20. The ratemaking treatment announced in D.87-11-013 related to the establishment of a memorandum account for fuel oil inventory carrying costs should be continued for those costs and similar memorandum accounts created for nuclear fuel carrying costs and coal inventory carrying costs for later potential recovery through ECAC.

21. Edison should include 100% of its adopted nuclear fuel carrying costs and coal inventory carrying costs in ECAC.

22. DRA's recommended methodology for calculating franchise fees and uncollectible accounts expense and resale accounts allocation is reasonable and should be adopted.

23. The parties' stipulated ERI value of 0.43 is reasonable and should be adopted.

24. The "QFs Out" run performed in this proceeding to develop Edison's final IER should reflect the return to service of Etiwanda 1 and 2 and San Bernardino 1 and 2 as cold standby units for the two-month period in which a capacity shortage is forecast.

25. In determining Edison's final IER, Edison's system capacity should be de-rated for forced outages and maintenance in the manner proposed by DRA and Edison.

26. DRA's proposed commit target values for the forecast period are reasonable and should be adopted.

27. DRA's proposed approach to determining Edison's fixed gas costs is reasonable and should be adopted.

28. Avoided gas costs should be reflected in QF energy payments in a manner consistent with D.88-07-024.

29. DRA's final revenue requirement and IER proposals contained in its comments to the ALJ's proposed decision should be adopted.

30. A revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all customer groups is reasonable and should be adopted in this proceeding.

31. The rate change authorized in this decision should coincide with the change from the summer to winter residential baseline period for Edison's domestic customers in Baseline Region 15 and should reflect the realignment of baseline and Tier II rates adopted today in I.88-07-009.

32. The base rate revenue requirement should remain unchanged in this proceeding except for authorized revenue changes since the interim decision (D.88-05-024).

33. Edison's MAAC, CLMAC, and base rates should be revised in this proceeding to reflect the new, adopted sales level.

34. Rate sub-elements within Edison's ECAC rate (Chevron Settlement Rate, Uranium Contract Termination Rate, LSFO Inventory Writedown Rate, and Distillate Inventory Writedown Rate) should be revised in this proceeding to reflect the new, adopted sales level.

35. Street light facilities charges should be excluded from both SAPC and EPMC revenue allocations.

36. Consistent with our approach in D.87-12-066, interruptible credits should continue to be allocated on an EPMC basis to the large power class.

37. The off-peak energy charge contained in Edison's time-of-use schedules listed in Appendix D to this decision and the second block energy rate for Rate Schedules GS-2 and PA-2 should be 5-cents/KWh.

38. Except for the off-peak energy charges and the second block energy charges contained in the schedules listed in Appendix D, all other charges should be changed as a result of the revenue increased authorized in this decision in accordance with DRA's CEPC rate design.

ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission, on or after the effective date of this order, and at least 5 days prior to their effective date, revised tariffs schedules for electric rates based on the adopted revenue requirement reflected in Appendix C to this decision.

2. The revised tariff schedules shall become effective on or after October 1, 1988, and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. Edison's baseline and Tier II domestic rates shall reflect the decision issued today in I.88-07-009 as shown in Appendix D to this decision.

4. The temporary suspension of Edison's Annual Energy Rate (AER) adopted in D.88-05-024 shall be continued until the end of the Forecast Period, unless the Commission modifies the term of the suspension in a subsequent order.

5. Effective October 1, 1988, Edison's base rate revenue requirement shall remain unchanged except for authorized revenue changes since the interim decision, but Edison's base rates shall be revised to reflect the sales level adopted in this proceeding. Edison's Major Additions Adjustment Clause (MAAC) rates, Conservation and Load Management Adjustment Clause rates, and the amortization rates set forth in Appendix C shall similarly be revised to reflect the new sales level. (See, Appendix C to this decision.)

6. The ratemaking treatment announced in D.87-11-013 involving the establishment of a memorandum account for Edison's fuel oil inventory carrying costs shall be continued for those costs, and similar memorandum accounts shall be created for Edison's nuclear fuel carrying costs and coal inventory carrying costs for later potential recovery through ECAC. Edison is directed to include 100% of its adopted nuclear fuel carrying costs and coal inventory carrying costs in its ECAC balancing account.

7. An Energy Reliability Index value of 0.43 and an annual Incremental Energy Rate (IER) of 9,763 Btu/kWh shall be adopted in this proceeding. DRA's proposed time-differentiated IERs shall also be adopted.

8. A revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all groups shall be adopted in this proceeding.

9. The revenue allocation adopted in this proceeding shall be based on Edison's total adopted revenue requirement as of October 1, 1988. Details are shown in Appendices B and C to this decision.

10. Effective October 1, 1988, Edison's off-peak energy charge included in the tariff schedules listed in Appendix D to this decision and the second block energy rate for Rate Schedules GS-2 and PA-2 shall be returned to the 5-cent/kWh level authorized in D.87-12-066 following an inadvertent increase in that charge in D.88-05-074.

11. Effective October 1, 1988, except for the off-peak energy charge and the second block energy charges referenced above, all other demand and energy charges shall be increased as a result of the rate change authorized in this decision in accordance with DRA's Class Equal Percent Change rate design.

12. Edison's petition to set aside submission and reopen hearings in the forecast phase of this proceeding is denied.

This order is effective today.

Dated September 14, 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

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

Victor Weisser

Victor Weisser, Executive Director

LIST OF APPEARANCES

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

Interested Parties: Lindsay, Hart, Neil & Weigler, by Michael Alcantar and Paul J. Kaufman, Attorneys at Law, for Cogenerators of Southern California; Barbara Barkovich, for CLECA, California Steel Producers Group; Jackson, Tufts, Cole & Black, by Allan Thompson and William Booth, Attorneys at Law, for CLECA; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; R. H. Berby, for CLECA; Matthew Brady and Dian M. Grueneich, Attorneys at Law, for California Department of General Services; Deborah Bosch, for Energy Modeling Forum; David Branchcomb, for Henwood & Associates, Inc.; McCracken, Byers & Martin, by David J. Byers, Attorney at Law, and Reed V. Schmidt, for California Street Light Association; Bryan Cope, for Sierra Energy and Risk Assessment, Inc.; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Sam DeFrawi, for Naval Facilities Engineering Command; Karen Edson, for KKE & Associates; Mike Florio, Attorney at Law, for TURN; Steven Geringer, Attorney at Law, for California Farm Bureau Federation; Cynthia Hall, Attorney at Law, for Department of the Navy; Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobile Home Association; Jan Hamrin, for Independent Energy Producers; William Marcus, for JBS Energy, Inc.; Graham & James, by Robert C. Lopardo and Martin A. Mattes, Attorneys at Law, for California Hotel and Motel Association; A. Kirk McKenzie and Antonia Radillo, Attorneys at Law, for California Energy Commission; John D. Quinley, for Cogeneration Service Bureau; T. D. Clarke, R. B. Keeler, Attorneys at Law, and R. M. Rawlings, for Southern California Gas Company; Donald G. Salow, for Association of California Water Agencies; Donald W. Schoenbeck, for Cogenerators of Southern California; Gary Simon and Steve Harris, for El Paso Natural Gas; Clark Smith, for Transwestern Pipeline Company; James D. Squeri, for California Building Industry Association; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Christopher T. Ellison, Attorneys at Law, for Industrial Users; Michael R. Weinstein,

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Attorney at Law, for San Diego Gas & Electric Company; Harry K. Winters, for University of California; Bill Dixon, Carl Wood, and John Chabot, for Utility Workers Union of America; Lawrence E. DeSimone, for Energy Management Associates, Inc.; Norman Furuta, Attorney at Law, for Federal Executive Agencies; and Harvey Mark Eder, for Public Solar Power Coalition and himself; and Graham & James, by Norman Pederson, Attorney at Law, Kathryn L. Stein, and Robert Weisenmiller, for themselves.

Division of Ratepayer Advocates: Carol Matchett and Robert C. Cagen, Attorneys at Law, Bill Y. Lee, and Meg Gottstein.

Commission Advisory and Compliance Division: Frank Cruz.

(END OF APPENDIX A)

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Adopted Base Rate Revenue Requirement - California Jurisdiction

Line	Annual Revenues ($ million)	Effective Date	Item
	(a)	(b)	(c)
1	$ 3,239.665	1/1/88	Authorized Level of Base Rate Revenues
	Changes to base rate revenue requirement since 1/1/88:		
2	19.967	1/20/88	Palo Verde 3 COD
3	20.191	2/1/88	Palo Verde 1 phase-in
4	11.139	3/18/88	Palo Verde 3 base rates
5	20.191	9/19/88	Palo Verde 2 phase-in
6	7.190	10/1/88	Tax Reform Act true-up
7	+ (4.071)	"	Palo Verde base rate true-up
8	$ 3,314.271	10/1/88	Total base rate revenue requirement (including facilities charges)

Notes:

Line 1. A.86-12-047, D.87-12-066.

Line 2. A.L. 777-E, Res. E-3077; noninvestment expenses and decommissioning.

Line 3. I.85-05-001, D.86-10-023, A.L. 774-E.

Line 4. A.87-08-054, D.88-03-022.

Line 5. A.L. 795-E-A, approved without Commission Resolution.

Line 6. A.L. 783-E-A, Res. E-3105; subject to adjustment pending further Commission review.

Line 7. A.L. 799-E, approval on 40 days notice anticipated 9/26/88.

(END APPENDIX B)

SOUTHERN CALIFORNIA EDISON COMPANY
Revenue Changes Adopted for Revenue Allocation and Rate Design - California Jurisdiction
ECAC Forecast Period June 1, 1988-May 31, 1989

LINE	REVENUE ELEMENT	PRESENT RATE REVENUE 1/ 2/ 3/ ($ million)	REVENUE CHANGE ($ million)	ADOPTED REVENUE ($ million)	AVERAGE RATE (cents/kwh)
	(a)	(b)	(c)	(d)	(e)
1	Base rates	$3,318.781	($4.510)	$3,314.271 4/	5.075
2	Major Additions Adjustment Clause (MAAC)				
3	SONGS 2 and 3 post-COD	52.903	(0.304) 5/	52.599	0.080
4	Balsam Meadow	36.576	(0.747) 5/	35.829	0.055
5	Devers-Valley-Serrano	19.594	(0.152) 5/	19.442	0.030
6	SONGS pre-COD balancing account	8.491	(0.251) 5/	8.240	0.013
7	TOTAL MAAC	117.564	(1.454) 5/	116.110	0.178
8	Conservation Load Management Adjustment Clause (CLMAC)	(16.981)	0.211 5/	(16.770)	(0.026)
9	Energy Cost Adjustment Clause (ECAC)				
10	Fuel and purchased power	2,021.767	181.966	2,203.733	3.374
11	Balancing account	(137.808)	136.024	(1.784)	(0.003)
12	LSFO writedown	54.862	(1.930) 5/	52.932	0.081
13	Distillate writedown	4.572	0.120 5/	4.692	0.007
14	Chevron settlement	204.427	(2.541) 5/	201.886	0.309
15	Uranium contract termination	77.721	(0.966) 5/	76.755	0.118
16	TOTAL ECAC	2,225.541	312.673	2,538.214	3.886
17	Annual Energy Rate (AER)	0.000	0.000	0.000	0.000
18	Electric Revenue Adjustment Billing Factor (ERABF)	(9.143)	(41.940)	(51.083)	(0.078)
19	SUBTOTAL	5,635.762	264.979	5,900.742 6/	9.035
20	Other Operating Revenue	57.547	0.000	57.547	
21	CPUC fees	7.841	0.000	7.841	
22	TOTAL	$5,701.150	$264.979	$5,966.129	

1/ Based on adopted ECAC sales of 65,310.25 GWH, after adjustment for employee discounts and exclusion of fringe and Sequoia sales (65,340 GWH unadjusted).
2/ Present rates using current tariffs, which were made effective 6/1/88.
3/ Present rate revenues reflect test year 1988 optional TOU meter charges, and differ slightly from interim Decision 88-05-074. Recovery of revenue for optional TOU meters will be reflected in attrition per Decision 87-12-066.
4/ Revenues from Appendix B, reflects revenue changes due to revised sales forecast and other authorized base revenue changes effective 10/1/88.
5/ Revenue change due solely to revised sales forecast.
6/ Revenue used for revenue allocation and rate design.

(END APPENDIX C)

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY ECAC

RATE APPENDIX

- Residential Rates
- Small and Medium Power Rates
- Large Power Rates and Interruptible Rates
- Standby Rates and Real Time Pricing Rates
- Agricultural Rates
- Streetlighting Rates

NOTE: Rates in this appendix reflect PUC surcharge fee of $.00012/KWh which is added after rate design.

APPENDIX D
PAGE 1
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED RESIDENTIAL RATES

EFFECTIVE 10-01-88
($/KWH)

SCHEDULE	D	TOU-D b/	
SEASON	ANNUAL	SUMMER	WINTER
MINIMUM BASE RATE CHARGE ($/DAY)	$0.10	$0.10	$0.10
TIER 1 ENERGY RATE a/	$0.07869	--	--
TIER 2 ENERGY RATE	$0.12004	--	--
ON-PEAK ENERGY RATE	--	$0.39656	--
MID-PEAK ENERGY RATE	--	$0.15291	$0.12424
OFF-PEAK ENERGY RATE	--	$0.07321	$0.07321
TOU-D BASELINE CREDIT	--	$0.04135	$0.04135
METER CHARGE ($/DAY)	--	$0.15	$0.15

a/ The Tier 1 energy rate (Baseline) is 87% of the System Average Rate (SAR), where the SAR is total revenue requirement from sales divided by total sales ($5,900.849 MM / 65,340 MMKWH = 0.09031 $/KWH).

b/ TOU-D energy rates are reduced by baseline credit for an amount equal to their otherwise applicable baseline allowance, but no more than their actual kwh usage.

SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED RESIDENTIAL RATES

Baseline Allowances
Schedule Nos. D, DMS-1, DMS-2, DAPS-2, DE, and D-PG

Monthly Baseline kWh Allowances:

Line No.	Baseline Region (1)	Summer Basic (2)	Summer All-Electric (3)	Winter Basic (4)	Winter All-Electric (5)
1.	10	252	302	259	493
2.	13	441	800	321	1,072
3.	14	363	532	292	855
4.	15	1,200	1,200	330	670
5.	16	250	445	279	1,035
6.	17	333	425	278	615

Adopted Daily Baseline kWh Allowances:

Line No.	Baseline Region (1)	Summer Basic (2)	Summer All-Electric (3)	Winter Basic (4)	Winter All-Electric (5)
1.	10	8.2	9.8	8.6	16.3
2.	13	14.4	26.1	10.6	35.5
3.	14	11.8	17.3	9.7	28.3
4.	15	39.3	39.3	10.9	22.1
5.	16	8.2	14.5	9.2	34.3
6.	17	10.9	13.9	9.2	20.4

Schedule DM

Adopted Daily Baseline kWh Allowances:

Line No.	Baseline Region	Summer Basic	Summer All-Electric	Winter /1 Basic	Winter /1 All-Electric
1.	10	4.7	5.6	5.0	9.4
2.	13	6.8	12.4	5.1	17.0
3.	14	6.9	10.2	5.9	17.4
4.	15	20.7	20.7	6.4	13.0
5.	16	6.6	11.8	6.5	24.1
6.	17	6.0	7.7	5.3	11.7

/1 Winter season for Baseline Regions 10, 13, 14, 16 and 17 is November 1 through April 30. Winter season for Region 15 is October 1 through May 31.

APPENDIX D
PAGE 3
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED SMALL AND MEDIUM POWER RATES

EFFECTIVE 10-01-88
($/KWH)

SCHEDULE	GS-SP/TP	TC-1	GS-2	
SEASON	ANNUAL	ANNUAL	SUMMER	WINTER
CUSTOMER CHARGE	$0.30/DAY	$0.30/DAY	$32.35/MONTH	$32.35/MONTH
DEMAND CHARGE ($/KW/MONTH)	--	--	$8.95	$2.80
TIER 1 ENERGY RATE (FIRST 300 KWH PER KW)	--	--	$0.08235	$0.08235
TIER 2 ENERGY RATE (EXCESS)	--	--	$0.05012	$0.05012
FLAT ENERGY RATE	$0.10516	$0.09127	--	--

NOTES:

1. GS-1 replaced by GS-SP (single phase) and GS-TP (three phase).

2. GS-TP: limited to existing GS-1 three phase customers at present and to be phased out by 12/31/90. Thereafter, these three phase customers will be assigned to GS-2, TOU-GS, PA-1 or PA-2 based on operational characteristics.

APPENDIX D
PAGE 4
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED SMALL AND MEDIUM POWER TIME-OF-USE RATES

EFFECTIVE 10-01-88
($/KWH)

SCHEDULE	TOU-GS		TOU-GS-SOP		
SEASON	SUMMER	WINTER	SUMMER	SPRING/FALL	WINTER
CUSTOMER CHARGE	$32.35/MONTH	$32.35/MONTH	$32.35/MONTH	$32.35/MONTH	$32.35/MONTH
TIME RELATED DEMAND CHARGE ($/KW/MONTH):					
ON-PEAK	$12.20	--	$35.55	--	--
MID-PEAK	$1.90	--	$0.95	$0.50	$0.50
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH) a/	$2.80	$2.80	$2.80	$2.80	$2.80
ON-PEAK ENERGY RATE	$0.11627	--	$0.10846	--	--
MID-PEAK ENERGY RATE	$0.09410	$0.10571	$0.10846	$0.08224	$0.08961
OFF-PEAK ENERGY RATE	$0.05012	$0.05012	$0.07157	$0.07640	$0.07640
SUPER OFF-PEAK ENERGY RATE	--	--	$0.03512	$0.03512	$0.03512
METER CHARGE ($/MONTH)	$7.00	$7.00	$7.00	$7.00	$7.00

SCHEDULE CHANGES:

1. TOU-GS-SOP: new schedule for TOU-GS customers, providing fourth TOU period (i.e., midnight to 6 AM). See detail on TOU-GS-SOP and TOU-E-SOP periods, page 7 of this appendix.

a/ Unratcheted.

APPENDIX D
PAGE 5
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER RATES

EFFECTIVE 10-01-88
($/KWH)

SCHEDULE	TOU-8			TOU-8-SOP		
VOLTAGE	SECONDARY	PRIMARY	SUBTRANS.	SECONDARY	PRIMARY	SUBTRANS.
CUSTOMER CHARGE	$267.75	$265.25	$262.00	$267.75	$265.25	$262.00
TIME RELATED DEMAND CHARGE ($/KW/MONTH)						
SUMMER ON-PEAK	$14.20	$13.80	$11.75	$35.35	$35.00	$33.00
SUMMER MID-PEAK	$2.20	$2.10	$1.85	$0.95	$0.95	$0.90
SPRING/FALL MID-PEAK	--	--	--	$0.50	$0.50	$0.45
WINTER MID-PEAK	--	--	--	$0.50	$0.50	$0.45
TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$2.90	$2.10	$0.25	$2.90	$2.10	$0.25
SUMMER ENERGY CHARGE:						
ON-PEAK	$0.10407	$0.09493	$0.07622	$0.10416	$0.09492	$0.08772
MID-PEAK	$0.08423	$0.07683	$0.06169	$0.10416	$0.09492	$0.08772
OFF-PEAK	$0.05012	$0.05012	$0.05012	$0.06871	$0.06281	$0.05871
SUPER OFF-PEAK	--	--	--	$0.03512	$0.03512	$0.03512
SPRING/FALL ENERGY CHARGE:						
ON-PEAK	--	--	--	--	--	--
MID-PEAK	--	--	--	$0.07897	$0.07218	$0.06677
OFF-PEAK	--	--	--	$0.07332	$0.06702	$0.06200
SUPER OFF-PEAK	--	--	--	$0.03512	$0.03512	$0.03512
WINTER ENERGY CHARGE:						
MID-PEAK	$0.09462	$0.08631	$0.06930	$0.08619	$0.07915	$0.07407
OFF-PEAK	$0.05012	$0.05012	$0.05012	$0.07332	$0.06702	$0.06200
SUPER OFF-PEAK	--	--	--	$0.03512	$0.03512	$0.03512
RATE LIMITER:						
AVERAGE SUMMER	$0.12422	$0.12422	--	--	--	--
SUMMER ON-PEAK	$0.72681	$0.70682	$0.56770	--	--	--

APPENDIX D
PAGE 6
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER INTERRUPTIBLE RATES

EFFECTIVE 10-01-88
($/KWH)

SCHEDULE	TOU-8-SOP-I-A			TOU-8-SOP-I-B		
VOLTAGE	SECONDARY	PRIMARY	SUBTRANS	SECONDARY	PRIMARY	SUBTRANS
CUSTOMER CHARGE	$267.75	$265.25	$262.00	$267.75	$265.25	$262.00
TIME RELATED DEMAND CHARGE ($/KW/MONTH)						
SUMMER ON-PEAK	$24.55	$24.20	$22.65	$25.85	$25.50	$24.00
SUMMER MID-PEAK	$0.60	$0.60	$0.60	$0.65	$0.65	$0.65
SPRING/FALL MID-PEAK	$0.35	$0.35	$0.30	$0.35	$0.35	$0.30
WINTER MID-PEAK	$0.35	$0.35	$0.30	$0.35	$0.35	$0.30
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$2.90	$2.10	$0.25	$2.90	$2.10	$0.25
SUMMER ENERGY CHARGE:						
ON-PEAK	$0.10070	$0.09251	$0.08542	$0.10112	$0.09281	$0.08571
MID-PEAK	$0.10070	$0.09251	$0.08542	$0.10112	$0.09281	$0.08571
OFF-PEAK	$0.06559	$0.06073	$0.05612	$0.06597	$0.06099	$0.05637
SUPER OFF-PEAK	$0.03355	$0.03355	$0.03355	$0.03374	$0.03374	$0.03374
SPRING/FALL ENERGY CHARGE:						
ON-PEAK	--	--	--	--	--	--
MID-PEAK	$0.07677	$0.07005	$0.06473	$0.07704	$0.07031	$0.06498
OFF-PEAK	$0.07101	$0.06478	$0.05986	$0.07129	$0.06506	$0.06013
SUPER OFF-PEAK	$0.03355	$0.03355	$0.03355	$0.03374	$0.03374	$0.03374
WINTER ENERGY CHARGE:						
MID-PEAK	$0.08395	$0.07697	$0.07199	$0.08423	$0.07724	$0.07225
OFF-PEAK	$0.07110	$0.06487	$0.05994	$0.07137	$0.06513	$0.06020
SUPER OFF-PEAK	$0.03355	$0.03355	$0.03355	$0.03374	$0.03374	$0.03374

Note: The penalty provisions for TOU-8-SOP-I (A and B) are the same as those for I-6 (A and B).

APPENDIX D
PAGE 7
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER INTERRUPTIBLE RATES

EFFECTIVE 10-01-88
($/KWH)

SCHEDULE	I-5-A			I-5-B		
VOLTAGE	SECONDARY	PRIMARY	SUBTRANS	SECONDARY	PRIMARY	SUBTRANS
CUSTOMER CHARGE	$267.75	$265.25	$262.00	$267.75	$265.25	$262.00
TIME RELATED DEMAND CHARGE ($/KW/MONTH)						
SUMMER ON-PEAK	$14.20	$13.80	$11.75	$14.20	$13.80	$11.75
SUMMER MID-PEAK	$2.20	$2.10	$1.85	$2.20	$2.10	$1.85
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$2.90	$2.10	$0.25	$2.90	$2.10	$0.25
SUMMER ENERGY CHARGE:						
ON-PEAK	$0.08907	$0.07993	$0.06122	$0.10407	$0.09493	$0.07622
MID-PEAK	$0.06923	$0.06183	$0.04669	$0.08423	$0.07683	$0.06169
OFF-PEAK (TIER 1)	$0.02512	$0.02512	$0.02512	$0.05012	$0.05012	$0.05012
OFF-PEAK (TIER 2)	--	--	--	$0.02512	$0.02512	$0.02512
WINTER ENERGY CHARGE:						
MID-PEAK	$0.07962	$0.07131	$0.05430	$0.09462	$0.08631	$0.06930
OFF-PEAK (TIER 1) a/	$0.02512	$0.02512	$0.02512	$0.05012	$0.05012	$0.05012
OFF-PEAK (TIER 2) a/	--	--	--	$0.02512	$0.02512	$0.02512

SCHEDULE CREDITS:		b/ Adopted Credit ($/kw/SUMMER mo)
	Rate A	$8.10
	Rate B	$6.70
I-2:	Rate A	$8.30
	Rate B	$6.90
I-3:	Rate A (Energy Credit)	$2.50
	Rate B	$5.30
	Rate C	$4.00
	Rate D	$2.70
I-5:	Rate A (Energy Credit)	NO CHANGE
	Rate B (Energy Credit)	NO CHANGE

Note: I-5A rates equal TOU-8 rates minus 1.5 c/kwh for on-peak and mid-peak energy, and minus 2.5 c/kwh for off-peak energy. I-5B rates equal TOU-8 rates, except off-peak kwh beyond 300 kwh/kw of the Firm Service Level equal TOU-8 off-peak energy rates minus 2.5 c/kwh.

a/ See pp. 337-338 of D. 87-12-066 for note on off-peak rate floor.
b/ Developed by multiplying present credit by ratio of total TOU-8 on-peak kw to summer TOU-8 on-peak kw. Credits unchanged from the general rate case, D. 87-12-066.

APPENDIX D
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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED LARGE POWER INTERRUPTIBLE RATES

EFFECTIVE 10-01-88
($/KWH)

SCHEDULE	I-6 A			I-6 B		
VOLTAGE	SECONDARY	PRIMARY	SUBTRANS	SECONDARY	PRIMARY	SUBTRANS
CUSTOMER CHARGE	$267.75	$265.25	$262.00	$267.75	$265.25	$262.00
TIME RELATED DEMAND CHARGE ($/KW/MONTH)						
SUMMER ON-PEAK	$9.65	$9.40	$7.50	$10.20	$9.95	$8.05
SUMMER MID-PEAK	$1.50	$1.40	$1.20	$1.60	$1.50	$1.25
SPRING/FALL MID-PEAK	--	--	--	--	--	--
WINTER MID-PEAK	--	--	--	--	--	--
NON-TIME RELATED DEMAND CHARGE ($/KW/MONTH)	$2.90	$2.10	$0.25	$2.90	$2.10	$0.25
SUMMER ENERGY CHARGE:						
ON-PEAK	$0.09709	$0.08810	$0.06995	$0.09796	$0.08895	$0.07073
MID-PEAK	$0.07883	$0.07153	$0.05688	$0.07950	$0.07219	$0.05747
OFF-PEAK	$0.04554	$0.04554	$0.04554	$0.04611	$0.04611	$0.04611
SUPER OFF-PEAK	--	--	--	--	--	--
WINTER ENERGY CHARGE:						
MID-PEAK	$0.08899	$0.08094	$0.06435	$0.08969	$0.08161	$0.06496
OFF-PEAK	$0.04538	$0.04538	$0.04538	$0.04597	$0.04597	$0.04597
SUPER OFF-PEAK	--	--	--	--	--	--

APPENDIX D
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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED STANDBY RATES AND REAL TIME PRICING RATES

SCHEDULE S

RATES

Standby charge:

	SERVICE VOLTAGE	Per meter Per month
All kW of standby demand, per kW	Below 2 kV	$2.90
All kW of standby demand, per kW	2 kV to 50 kV	$2.10
All kW of standby demand, per kW	Above 50 kV	$0.25

REAL TIME PRICING

RTP:

Base Rate: $.04523/kWh

ECAC Rate: variable

RTP-2:

Customer Charge:

For service up to 2kV	$267.75	$2.90
For service at 2kV through 50 kV	$265.25	$2.10
For service above 50 KV	$262.00	$0.25

Base Rate: $ .04011
ECAC Rate: variable

APPENDIX D
PAGE 10
SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED AGRICULTURAL RATES
EFFECTIVE 10-01-88

RATE SCHEDULE	CUSTOMER CHARGE ($/MONTH)	METER CHARGE ($/MONTH)	DEMAND CHARGE ($/KW OR HP) SUMMER	DEMAND CHARGE ($/KW OR HP) WINTER	ENERGY CHARGE ($/KWH) TIER 1	ENERGY CHARGE ($/KWH) TIER 2
PA-2	$21.80	--	$7.80	$1.25	0.09350	0.05012
					SUMMER	WINTER
PA-1	$10.90	--	$1.10	$1.10	0.08687	0.08687
TOU-PA-1	$10.90	--	$3.00	$3.00	--	--
ON-PEAK	--	--	--	--	0.09758	0.09376
OFF-PEAK	--	--	--	--	0.06043	0.06136
U-ALMP-2	$10.90	--	--	--	--	--
ON-PEAK	--	--	--	--	0.23137	0.20385
OFF-PEAK	--	--	--	--	0.07474	0.07138
TOU-PA: Rate A	$32.70	$6.00	--	--	--	--
ON-PEAK	--	--	--	--	0.13434	--
MID-PEAK	--	--	--	--	0.10872	0.12214
OFF-PEAK	--	--	--	--	0.05012	0.05012
CONNECTED HP	--	--	$1.10	$1.10	--	--
TOU-PA-3 -SPLIT WEEK: Rate A	$32.70	$6.00	--	--	--	--
ON-PEAK	--	--	--	--	0.15609	--
MID-PEAK	--	--	--	--	0.12631	0.14191
OFF-PEAK	--	--	--	--	0.05012	0.05012
CONNECTED HP	--	--	$1.10	$1.10	--	--
TOU-PA-4 - REDUCED PEAK HOUR: Rate A	$32.70	$6.00	--	--	--	--
ON-PEAK	--	--	--	--	0.13661	--
MID-PEAK	--	--	--	--	0.11055	0.12420
OFF-PEAK	--	--	--	--	0.05012	0.05012
CONNECTED HP	--	--	$1.10	$1.10	--	--

APPENDIX D
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SOUTHERN CALIFORNIA EDISON COMPANY
ADOPTED AGRICULTURAL RATES

RATE SCHEDULE	CUSTOMER CHARGE ($/MONTH)	METER CHARGE ($/MONTH)	DEMAND CHARGE ($/KW OR HP) SUMMER	DEMAND CHARGE ($/KW OR HP) WINTER	ENERGY CHARGE ($/KWH) SUMMER	ENERGY CHARGE ($/KWH) WINTER
TOU-PA: Rate B	$32.70	$6.00	--	--	--	--
ON-PEAK	--	--	$6.55	--	0.13284	--
MID-PEAK	--	--	--	--	0.10750	0.12077
OFF-PEAK	--	--	--	--	0.05012	0.05012
NON-TIME RELATED DEMAND CHARGE	--	--	$1.25	$1.25	--	--
TOU-PA-3 - SPLIT WEEK: Rate B	$32.70	$6.00	--	--	--	--
ON-PEAK	--	--	$6.55	--	0.14421	--
MID-PEAK	--	--	--	--	0.11670	0.13111
OFF-PEAK	--	--	--	--	0.05012	0.05012
NON-TIME RELATED DEMAND	--	--	$1.25	$1.25	--	--
TOU-PA-4 -REDUCED PEAK HOUR: Rate B	$32.70	$6.00	--	--	--	--
ON-PEAK	--	--	$6.55	--	0.12896	--
MID-PEAK	--	--	--	--	0.10437	0.11725
OFF-PEAK	--	--	--	--	0.05012	0.05012
NON-TIME RELATED DEMAND CHARGE	--	--	$1.25	$1.25	--	--
TOU-PA-5	$32.70	$6.00	--	--	--	--
MINIMUM BILL: $500 PER MONTH						
ON-PEAK	--	--	$6.55	--	0.12354	--
MID-PEAK	--	--	--	--	0.09998	0.11232
OFF-PEAK	--	--	--	--	0.05012	0.05012
NON-TIME RELATED DEMAND CHARGE	--	--	$1.25	$1.25	--	--
TOU-PA-SOP -SUPER OFF-PEAK	$32.70	$6.00	--	--	--	--
ON-PEAK	--	--	$35.95	--	0.09895	--
OFF-PEAK	--	--	--	--	0.07181	0.06474
SUPER OFF-PEAK	--	--	--	--	0.03512	0.03512
NON-TIME RELATED DEMAND CHARGE	--	--	$1.25	$1.25	--	--

Southern California Edison Co.
Adopted Streetlighting Rates

A - ALL NIGHT SERVICE

	BASE ENERGY RATE	OFFSET ENERGY RATE *	KWH PER MONTH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	FACILITIES CHARGE	PROP. RATE ($/LAMP-MO) (4+5+6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
INCANDESCENT LAMPS							
1000 LUMEN	0.02684	0.04809	35.535	0.95376	1.70888	6.24	8.90
2500 LUMEN	0.02684	0.04809	69.690	1.87048	3.35139	6.24	11.46
4000 LUMEN	0.02684	0.04809	112.815	3.02795	5.42527	6.25	14.70
6000 LUMEN	0.02684	0.04809	154.560	4.14839	7.43279	6.20	17.78
MERCURY VAPOR LAMPS							
4000 LUMEN	0.02684	0.04809	45.195	1.21303	2.17343	6.23	9.62
7900 LUMEN	0.02684	0.04809	74.520	2.00012	3.58367	6.20	11.78
12000 LUMEN	0.02684	0.04809	103.845	2.78720	4.99391	6.23	14.01
21000 LUMEN	0.02684	0.04809	163.530	4.38915	7.86418	6.61	18.86
41000 LUMEN	0.02684	0.04809	277.035	7.43562	13.32261	6.67	27.43
55000 LUMEN	0.02684	0.04809	391.575	10.50987	18.83084	6.67	36.01
HIGH PRESSURE SODIUM							
4000 LUMEN	0.02684	0.04809	20.010	0.53707	0.96225	6.23	7.73
5800 LUMEN	0.02684	0.04809	28.635	0.76856	1.37706	6.20	8.35
9500 LUMEN	0.02684	0.04809	40.365	1.08340	1.94115	6.20	9.22
16000 LUMEN	0.02684	0.04809	66.585	1.78714	3.20207	6.24	11.23
22000 LUMEN	0.02684	0.04809	84.870	2.27791	4.08140	6.60	12.96
27500 LUMEN	0.02684	0.04809	107.985	2.89832	5.19300	6.62	14.71
50000 LUMEN	0.02684	0.04809	167.325	4.49100	8.04666	6.70	19.24
LOW PRESSURE SODIUM							
4800 LUMEN	0.02684	0.04809	21.735	0.58337	1.04524	6.77	8.40
8000 LUMEN	0.02684	0.04809	28.980	0.77782	1.39365	6.77	8.94
13500 LUMEN	0.02684	0.04809	45.195	1.21303	2.17343	7.70	11.09
22500 LUMEN	0.02684	0.04809	62.790	1.68528	3.01957	7.97	12.67
33000 LUMEN	0.02684	0.04809	79.005	2.12049	3.79935	7.72	13.64

* : Includes PUC Reimbursement fee

Southern California Edison Co.
Adopted Streetlighting Rates

LS-1

B - MIDNIGHT SERVICE

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	FACILITIES CHARGE	PROP. RATE ($/LAMP-MO) (4+5+6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
INCANDESCENT LAMPS							
1000 LUMEN	0.03419	0.04809	17.943	0.61347	0.86258	6.24	7.72
2500 LUMEN	0.03419	0.04809	35.188	1.20308	1.69219	6.24	9.14
4000 LUMEN	0.03419	0.04809	56.983	1.94756	2.73935	6.25	10.94
6000 LUMEN	0.03419	0.04809	78.042	2.66826	3.75304	6.20	12.62
MERCURY VAPOR LAMPS							
4000 LUMEN	0.03419	0.04809	22.820	0.78022	1.09741	6.23	8.11
7900 LUMEN	0.03419	0.04809	37.627	1.28647	1.80948	6.20	9.30
12000 LUMEN	0.03419	0.04809	52.434	1.79272	2.52155	6.23	10.54
22000 LUMEN	0.03419	0.04809	82.571	2.82310	3.97084	6.61	13.40
41000 LUMEN	0.03419	0.04809	139.883	4.78260	6.72697	6.67	18.18
55000 LUMEN	0.03419	0.04809	197.717	6.75994	9.50821	6.67	22.94
HIGH PRESSURE SODIUM							
4000 LUMEN	0.03419	0.04809	10.104	0.34546	0.48590	6.23	7.06
5800 LUMEN	0.03419	0.04809	14.459	0.49435	0.69533	6.20	7.39
9500 LUMEN	0.03419	0.04809	20.381	0.69683	0.98012	6.20	7.88
[illegible]000 LUMEN	0.03419	0.04809	33.621	1.14950	1.61683	6.24	9.01
[illegible]2000 LUMEN	0.03419	0.04809	42.853	1.46514	2.06080	6.60	10.13
27500 LUMEN	0.03419	0.04809	54.525	1.86421	2.62211	6.62	11.11
50000 LUMEN	0.03419	0.04809	84.487	2.88881	4.06298	6.70	13.65
LOW PRESSURE SODIUM							
4800 LUMEN	0.03419	0.04809	10.975	0.37524	0.52779	6.77	7.67
8000 LUMEN	0.03419	0.04809	14.633	0.50030	0.70370	6.77	7.97
13500 LUMEN	0.03419	0.04809	22.820	0.78022	1.09741	7.70	9.58
22500 LUMEN	0.03419	0.04809	31.704	1.08398	1.52465	7.97	10.58
33000 LUMEN	0.03419	0.04809	39.892	1.36391	1.91841	7.72	11.00

[illegible] : Includes PUC Reimbursement fee

Southern California Edison Co.
Adopted Streetlighting Rates

LS-2

A - MULTIPLE SERVICE/ALL NIGHT

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	FACILITIES CHARGE	PROP. RATE ($/LAMP-MO) (4+5+6)
INCANDESCENT LAMPS	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1000 LUMEN	0.02684	0.04809	35.535	0.95376	1.70888	0.79	3.45
2500 LUMEN	0.02684	0.04809	69.690	1.87048	3.35139	0.79	6.01
4000 LUMEN	0.02684	0.04809	112.815	3.02795	5.42527	0.79	9.24
6000 LUMEN	0.02684	0.04809	154.560	4.14839	7.43279	0.79	12.37
10000 LUMEN	0.02684	0.04809	238.050	6.38926	11.44782	0.79	18.63
MERCURY VAPOR LAMPS							
4000 LUMEN	0.02684	0.04809	45.195	1.21303	2.17343	0.79	4.18
7000 LUMEN	0.02684	0.04809	74.580	2.00118	3.58387	0.79	6.37
12000 LUMEN	0.02684	0.04809	103.845	2.78720	4.99391	0.79	8.57
21000 LUMEN	0.02684	0.04809	163.530	4.38915	7.86416	0.79	13.04
41000 LUMEN	0.02684	0.04809	277.035	7.43582	13.32281	0.79	21.55
55000 LUMEN	0.02684	0.04809	391.575	10.50987	18.83084	0.79	30.13
HIGH PRESSURE SODIUM							
4000 LUMEN	0.02684	0.04809	20.010	0.53707	0.96228	0.79	2.29
5800 LUMEN	0.02684	0.04809	28.635	0.76858	1.37706	0.79	2.94
9500 LUMEN	0.02684	0.04809	40.365	1.08340	1.94115	0.79	3.81
16000 LUMEN	0.02684	0.04809	66.585	1.78714	3.20207	0.79	5.78
22000 LUMEN	0.02684	0.04809	84.870	2.27791	4.08140	0.79	7.15
27500 LUMEN	0.02684	0.04809	107.985	2.89832	5.19300	0.79	8.88
37000 LUMEN	0.02684	0.04809	132.135	3.54850	6.35437	0.79	10.69
50000 LUMEN	0.02684	0.04809	167.325	4.49100	8.04666	0.79	13.33
LOW PRESSURE SODIUM							
4800 LUMEN	0.02684	0.04809	21.735	0.58337	1.04524	0.79	2.42
8000 LUMEN	0.02684	0.04809	28.980	0.77782	1.39365	0.79	2.96
13500 LUMEN	0.02684	0.04809	45.195	1.21303	2.17343	0.79	4.18
22500 LUMEN	0.02684	0.04809	62.790	1.68528	3.01957	0.79	5.49
33000 LUMEN	0.02684	0.04809	79.005	2.12049	3.79935	0.79	6.71

1. Includes PUC Reimbursement fee.

APPENDIX D

Southern California Edison Co.
Adopted Streetlighting Rates

B - MULTIPLE SERVICE/MIDNIGHT

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	FACILITIES CHARGE	PROP. RATE ($/LAMP-MO) (4+5+6)
INCANDESCENT LAMPS	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1000 LUMEN	0.03419	0.04809	17.943	0.61347	0.86288	0.79	2.27
2500 LUMEN	0.03419	0.04809	35.188	1.20308	1.69219	0.79	3.69
4000 LUMEN	0.03419	0.04809	56.983	1.94758	2.73935	0.79	5.48
6000 LUMEN	0.03419	0.04809	78.042	2.66825	3.75304	0.79	7.21
10000 LUMEN	0.03419	0.04809	120.198	4.10957	5.78032	0.79	10.68
MERCURY VAPOR LAMPS							
4000 LUMEN	0.03419	0.04809	22.820	0.78022	1.09741	0.79	2.67
7900 LUMEN	0.03419	0.04809	37.827	1.28647	1.80948	0.79	3.89
12000 LUMEN	0.03419	0.04809	52.434	1.79272	2.52155	0.79	5.10
21000 LUMEN	0.03419	0.04809	82.571	2.82319	3.97084	0.79	7.58
41000 LUMEN	0.03419	0.04809	139.883	4.78260	6.72697	0.79	12.30
55000 LUMEN	0.03419	0.04809	197.717	6.75994	9.50821	0.79	17.06
HIGH PRESSURE SODIUM							
4000 LUMEN	0.03419	0.04809	10.104	0.34546	0.48590	0.79	1.62
5800 LUMEN	0.03419	0.04809	14.459	0.49435	0.69533	0.79	1.98
9500 LUMEN	0.03419	0.04809	20.381	0.69683	0.98012	0.79	2.47
16000 LUMEN	0.03419	0.04809	33.621	1.14950	1.61883	0.79	3.56
22000 LUMEN	0.03419	0.04809	42.853	1.46514	2.06080	0.79	4.32
27500 LUMEN	0.03419	0.04809	54.525	1.86421	2.62211	0.79	5.28
37000 LUMEN	0.03419	0.04809	66.719	2.28112	3.20852	0.79	6.28
50000 LUMEN	0.03419	0.04809	84.487	2.88861	4.06298	0.79	7.74
LOW PRESSURE SODIUM							
4800 LUMEN	0.03419	0.04809	10.975	0.37524	0.52779	0.79	1.69
8000 LUMEN	0.03419	0.04809	14.833	0.50030	0.70370	0.79	1.99
13500 LUMEN	0.03419	0.04809	22.820	0.78022	1.09741	0.79	2.67
22500 LUMEN	0.03419	0.04809	31.704	1.08396	1.52465	0.79	3.40
33000 LUMEN	0.03419	0.04809	39.892	1.36391	1.91841	0.79	4.07

* : Includes PUC Reimbursement fee

APPENDIX D

Southern California Edison Co.
Adopted Streetlighting Rates

C - SERIES SERVICE/ALL NIGHT

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	FACILITIES CHARGE	PROP. RATE ($/LAMP-MO) (4+5+6)
INCANDESCENT LAMPS	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1000 LUMEN	0.02684	0.04809	29.528	0.79253	1.42000	3.55	5.76
2500 LUMEN	0.02684	0.04809	64.567	1.73298	3.10503	3.55	8.39
4000 LUMEN	0.02684	0.04809	97.638	2.62060	4.69541	3.55	10.87
6000 LUMEN	0.02684	0.04809	136.614	3.66872	6.56977	3.55	13.79
10000 LUMEN	0.02684	0.04809	227.559	6.10768	10.94331	3.55	20.60
MERCURY VAPOR LAMPS							
4000 LUMEN	0.02684	0.04809	51.675	1.38696	2.48505	3.55	7.42
7900 LUMEN	0.02684	0.04809	85.574	2.29681	4.11525	3.55	9.96
12000 LUMEN	0.02684	0.04809	117.819	3.16226	5.66592	3.55	12.38
21000 LUMEN	0.02684	0.04809	183.983	4.93757	8.84678	3.55	17.33
41000 LUMEN	0.02684	0.04809	314.184	8.43270	15.10911	3.55	27.09
55000 LUMEN	0.02684	0.04809	442.338	11.87235	21.27203	3.55	36.69
HIGH PRESSURE SODIUM							
4000 LUMEN	0.02684	0.04809	30.746	0.82522	1.47858	3.55	5.85
5800 LUMEN	0.02684	0.04809	40.834	1.09598	1.96371	3.55	6.61
9500 LUMEN	0.02684	0.04809	58.126	1.56018	2.79538	3.55	7.91
16000 LUMEN	0.02684	0.04809	83.590	2.24358	4.01984	3.55	9.81
27000 LUMEN	0.02684	0.04809	111.933	3.00428	5.38286	3.55	11.94
[illegible] PRESSURE SODIUM							
4800 LUMEN	0.02684	0.04809	24.225	0.65020	1.16498	3.55	5.37
8000 LUMEN	0.02684	0.04809	34.200	0.91793	1.64468	3.55	6.11
13500 LUMEN	0.02684	0.04809	61.750	1.65737	2.96956	3.55	8.18
22500 LUMEN	0.02684	0.04809	87.875	2.35857	4.22591	3.55	10.13
33000 LUMEN	0.02684	0.04809	104.025	2.79203	5.00258	3.55	11.34

[illegible] Includes PUC Reimbursement fee

APPENDIX D

Southern California Edison Co.
Adopted Streetlighting Rates

LS-2

D - SERIES SERVICE/MIDNIGHT

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	FACILITIES CHARGE	PROP. RATE ($/LAMP-MO) (4+5+6)
INCANDESCENT LAMPS	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1000 LUMEN	0.03419	0.04809	14.918	0.51005	0.71741	3.55	4.78
2500 LUMEN	0.03419	0.04809	32.620	1.11528	1.56870	3.55	6.23
4000 LUMEN	0.03419	0.04809	49.327	1.68649	2.37214	3.55	7.61
6000 LUMEN	0.03419	0.04809	69.018	2.35973	3.31908	3.55	9.23
10000 LUMEN	0.03419	0.04809	114.964	3.93062	5.52862	3.55	13.01
MERCURY VAPOR LAMPS							
4000 LUMEN	0.03419	0.04809	26.113	0.89260	1.25577	3.55	5.70
7900 LUMEN	0.03419	0.04809	43.242	1.47844	2.07951	3.55	7.11
12000 LUMEN	0.03419	0.04809	59.537	2.03557	2.86313	3.55	8.45
21000 LUMEN	0.03419	0.04809	92.981	3.17834	4.47049	3.55	11.20
41000 LUMEN	0.03419	0.04809	158.764	5.42814	7.63496	3.55	16.61
55000 LUMEN	0.03419	0.04809	223.523	7.64225	10.74922	3.55	21.94
HIGH PRESSURE SODIUM							
4000 LUMEN	0.03419	0.04809	15.539	0.53128	0.74727	3.55	4.83
5800 LUMEN	0.03419	0.04809	20.638	0.70551	0.99248	3.55	5.25
9500 LUMEN	0.03419	0.04809	29.379	1.03447	1.41284	3.55	5.97
16000 LUMEN	0.03419	0.04809	42.247	1.44442	2.03186	3.55	7.03
22000 LUMEN	0.03419	0.04809	58.572	1.93420	2.72055	3.55	8.20
LOW PRESSURE SODIUM							
4800 LUMEN	0.03419	0.04809	12.240	0.41849	0.58862	3.55	4.56
8000 LUMEN	0.03419	0.04809	17.280	0.59080	0.83100	3.55	4.97
13500 LUMEN	0.03419	0.04809	31.200	1.06673	1.50041	3.55	6.12
22500 LUMEN	0.03419	0.04809	44.400	1.51804	2.12520	3.55	7.20
33000 LUMEN	0.03419	0.04809	52.560	1.79703	2.52761	3.55	7.87
NON STANDARD LAMPS							
ALL NIGHT MULT	0.02884	0.04809	88	2.36192	4.23192	0.79	7.38
ALL NIGHT SERIES	0.02884	0.04809	100	2.88400	4.80900	3.55	11.04
MIDNIGHT MULT	0.03419	0.04809	44	1.50436	2.11596	0.79	4.41
MIDNIGHT SERIES	0.03419	0.04809	50	1.70950	2.40450	3.55	7.66

* : Includes PUC Reimbursement fee

APPENDIX D

Southern California Edison Co.
Adopted Streetlighting Rates

[illegible]LLNIGHT SERVICE

A - ALL NIGHT SERVUCE

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	FACILITIES CHARGE	PROP. RATE ($/LAMP-MO) (4+5+6)
MERCURY VAPOR LAMPS	(1)	(2)	(3)	(4)	(5)	(6)	(7)
175 LUMEN	0.02684	0.04809	74.520	2.00012	3.58367	5.09	10.67
400 LUMEN	0.02684	0.04809	168.460	4.52147	8.10124	5.50	18.12
HIGH PRESSURE SODIUM							
70 LUMEN	0.02684	0.04809	28.835	0.76856	1.37706	5.09	7.24
100 LUMEN	0.02684	0.04809	40.365	1.08340	1.94115	5.09	8.11
200 LUMEN	0.02684	0.04809	84.870	2.27791	4.08140	5.49	11.85
DL-1 MIDNIGHT SERVICE							
MERCURY VAPOR LAMPS							
175 LUMEN	0.03419	0.04809	37.627	1.28647	1.80948	5.09	8.19
400 LUMEN	0.03419	0.04809	82.571	2.82310	3.97084	5.50	12.29
HIGH PRESSURE SODIUM							
70 LUMEN	0.03419	0.04809	14.459	0.49435	0.69533	5.09	6.28
100 LUMEN	0.03419	0.04809	20.381	0.69683	0.98012	5.09	6.77
200 LUMEN	0.03419	0.04809	42.853	1.46514	2.06080	5.49	9.02
[illegible]							
DL-1 POLE CHARGE							
	0.00000	0.00000	0.000	0.00000	0.00000	2.20	2.20

[illegible]: Includes PUC Reimbursement fee

Southern California Edison Co.
Adopted Streetlighting Rates

	BASE ENERGY RATE	OFFSET ENERGY RATE	KWH PER MONTH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	FACILITIES CHARGE	PROP. RATE (S/LAMP-MO) (4+5+6)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
RATE A	0.02684	0.04809	32.341	0.86803	1.55528	6.55	8.97
RATE B	0.02684	0.04809	32.341	0.86803	1.55528	2.15	4.57
RATE C	0.00000	0.00000	0.000	0.00000	0.00000	0.40	0.40

LS-3

	BASE ENERGY RATE	OFFSET ENERGY RATE	ANNUAL GWH	BASE ENERGY CHG. (1*3)	OFFSET ENERGY CHG. (2*3)	CUSTOMER CHARGE
	(1)	(2)				
TOTAL ENERGY	0.02684	0.04809	30.4	815,936	1,461,938	
CUSTOMER CHARGE						
MULTIPLE	0	0.00000	0	0	0	8.82
SERIES	0	0.00000	0	0	0	108.75
RELAMPING	0	0	0	0	0	0.41

(End of Appendix D)

* : Includes PUC Reimbursement fee

ALJ/SSM/vdl

Decision _____

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of the Southern California Edison Company (U 338-E) for: (1) Authority to Increase Its Energy Cost Adjustment Billing Factors, Increase Its Annual Energy Rate, and Increase Its Electric Revenue Adjustment Billing Factor Effective June 1, 1988; (2) Authority to Implement Modifications to its Energy Cost Adjustment Clause as More Specifically Set Forth in this Application; (3) Authority to Revise the Incremental Energy Rate, the Energy Reliability Index, and Avoided Cost Pricing; (4) Review of the Reasonableness of Edison's Operations During the Period from December 1, 1986, through November 30, 1987; and (5) Review of the Reasonableness of Edison Payments to Qualifying Facilities Under Nonstandard Contracts During the Period from December 1, 1984, through November 30, 1987.	Application 88-02-016 (Filed February 11, 1988)

(See Appendix A for appearances.)

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O P I N I O N

Phase I: Forecast Phase
Revenue Requirements and QF Payments

A. Background

By this application, the Southern California Edison Company (Edison) originally requested an increase of $627.9 million in its electric rates on an annualized basis effective June 1, 1988. This requested increase of approximately 11.6 percent above present rate levels was based on revenue requirement increases related to Edison's Energy Cost Adjustment Clause (ECAC), Annual Energy Rate (AER), and Electric Revenue Adjustment Mechanism (ERAM). Additionally, Edison sought approval of the reasonableness of its operations for the 1987 reasonableness review period and the reasonableness of its nonstandard contracts with qualifying facilities for a three-year period beginning December 1, 1984.

In revisions to its ECAC filing based on more recent resource mix, energy price, and recorded balancing account information, Edison first reduced its requested revenue requirement to $484.1 million on March 28, 1988. On May 14, 1988, Edison submitted additional prepared testimony further reducing this request to $479.4 million. In a brief filed on June 24, 1988, Edison states that its final proposed annual revenue increase is $456 million, a system average percentage increase of 8.4%.

Following a prehearing conference on February 26, 1988, an Administrative Law Judge (ALJ) ruling was issued on March 2, 1988, bifurcating this proceeding into two phases. The first phase was to consider those issues relating to the forecasts of fuel costs and resource mix and variable payments to qualifying facilities. The second phase, to be heard following the issuance of the forecast decision, was to focus on issues related to the reasonableness of Edison's operations.

The ALJ ruling also indicated that the Commission would consider, following comments by the parties, Edison's request for interim relief by its June 1, 1988, revision date. Edison had argued, among other things, that due to several issues new to the ECAC, the delay in a decision by its revision date would be detrimental to Edison. Specifically, Edison proposed that interim relief involve either adoption of Edison's proposed AER or its suspension on an interim basis. It was Edison's opinion that such relief would mitigate the risks to ratepayers and shareholders from either understatement or overstatement of AER revenues during periods of changing energy prices.

On May 25, 1988, the Commission issued Decision (D.) 88-05-074 in this proceeding. By that decision, Edison was authorized to increase, on an interim basis, its Energy Cost Adjustment Clause revenue requirement by $200 million. This change was to result in a 3.7% system average percentage increase over present rates to all customer classes, except streetlighting for which a 1.9% increase was authorized. Prior to the decision being issued, the Commission's Division of Ratepayer Advocates (DRA) had completed its forecast evaluation report recommending a revenue increase for Edison of $382.5 million.

D.88-05-074 also provided for the temporary suspension of Edison's Annual Energy Rate (AER) procedure. By D.88-07-066, issued July 22, 1988, D.88-05-074 was modified to provide greater specificity as to how the temporary AER suspension adopted in D.88-05-074 was to be implemented in rates.

Ten days of hearings in the forecast phase of this proceeding were held between May 23 and June 6, 1988, in San Francisco, California. This matter was submitted upon the filing of concurrent opening briefs on June 24, 1988, and concurrent reply briefs on July 1, 1988. The parties filing briefs in this proceeding included Edison, DRA, the California Cogeneration Council and the Cogenerators of Southern California (CCC/CSC), the

Federal Executive Agencies (FEA), the California Manufacturers Association (CMA), the California Large Energy Consumers Association (CLECA), the Industrial Users (IU), the California City-County Street Light Association (CAL-SLA), and Toward Utility Rate Normalization (TURN).

Following the close of hearings, but before the receipt of briefs, several parties submitted late-filed exhibits indicating their proposed revenue allocations based on the most recent revenue requirements updates. Additionally, at the ALJ's direction, the Division of Ratepayer Advocates (DRA), on June 22, 1988, mailed a set of updated tables reflecting DRA's current recommendations on the Incremental Energy Rate (IER), revenue requirements, and revenue allocation.

As stated previously, Edison's final proposed annual revenue increase is $456 million. The components of this rate increase request include the following: an increase of $454 million for the Energy Cost Adjustment Billing Factors (ECABF), an increase of $44 million for Edison's AER, and a decrease of $42 million for the Electric Revenue Adjustment Billing Factor (ERABF).

According to Edison, when the impact of Edison's interim rate relief authorized in D.88-05-074 is considered the net annualized revenue increase is $256 million. The components of this increase include an increase of $74 million in the ECABF, an increase of $224 million in the AER, and a decrease of $42 million in the ERABF.

The updated tables provided by DRA on June 22, 1988, have been included in the record as late-filed Exhibit 77. According to this document, DRA's final recommended revenue increase is $384 million. The components of this increase include an increase of $389 million in ECAC, an increase of $37 million in the AER, and a decrease of $42 million in ERAM.

B. ECAC Issues

The focus and purpose of an ECAC proceeding has traditionally been to enable a utility's rates to reflect changes in its fuel and purchase power expenses on an annual basis outside of the three-year general rate case cycle. Edison's current ECAC continues the consideration of these "traditional" ECAC issues. In addition, however, this proceeding also marks the beginning of the regular annual updating in ECAC of key components in the calculation of prices paid for power sold to the utility by qualifying facilities (QFs).

These QF issues have been added to the ECAC as a result of D.88-03-026 in the generic standard offer proceeding, A.82-04-044, et al. In that decision, the Commission concluded that annual updating of variable QF payments should take place in a utility's ECAC proceeding. In that decision, the Commission reasoned that it was preferable "not to create a unique proceeding for QFs [for this purpose], but rather to make optimal use of ECAC by setting QF prices at the same time (and from the same assumptions) that we adjust utility rates." (D.88-03-026, at p. 3.)

Variable QF prices are actually the sum of two basic components: a variable payment for capacity and a variable payment for energy. Critical to the determination of these payments are the utility's Energy Reliability Index (ERI) and Incremental Energy Rate (IER). The ERI is used to adjust the value of a combustion turbine on which the QF's capacity payment is based. The IER, which reflects the utility's incremental efficiency in converting heat energy to electricity, is multipled by the utility's incremental fuel cost to produce the price paid by the utility for the QF's energy output.

ERI and IER values are generally derived from the results produced by production cost models. These models are designed to simulate the manner in which utility resources meet system loads.

This simulation is driven by the resource and load assumptions which are chosen as inputs into the model.

Edison's IER and ERI were most recently determined in its test year 1988 general rate case (A.86-12-047). In anticipation of the annual updating of these QF payment components, the Commission in D.87-12-066 in that proceeding adopted a procedure to be followed in developing and presenting testimony related to the IER and ERI. The purpose of this procedure was to ensure the full exchange and understanding of models and data used to develop the IER and ERI.

Specifically, the Commission required that all parties to future Edison ECAC and general rate case proceedings use the ELFIN production cost model in developing a "base case" run. (D.87-12-066, at p. 203.) The Commission reasoned that use of the same model "to present a base case will aid the Commission, as a starting point, in determining whether model, assumption, or methodological differences are causing the different results." (Id.) Each party, however, was also given the opportunity to present additional testimony using its model of choice. (Id.)

Additionally, the Commission directed that "a workshop be held no later than one week following Edison's ECAC filing to determine the data sets, resource plans, load shape, heat rate input, unit commitment and dispatch, minimum load conditions, resource assumptions, marginal fuel assumptions, and all other pertinent data which Edison used to calculate its IER." (D.87-12-066, at p. 205.) The workshop was also to serve as a forum for the parties to agree, to the extent possible, on the assumptions to be used and the appropriate source of those assumptions. The Director of the Commission Advisory and Compliance Division (CACD) was to appoint an arbiter for the workshop to resolve any issues related to the development of a common data set upon which agreement could not be reached.

In compliance with these directives, on January 25, 1988, the CACD noticed a workshop to develop common data set assumptions for ELFIN computer model runs to be used in this proceeding. The workshops were held on February 17 and 18 and March 3, 1988, with Linda Gustafson of the CACD serving as arbiter. On March 16, 1988, the common data set for a base case ELFIN run to which the workshop participants had agreed was served on all parties by the CACD.

The issues litigated in this phase of Edison's ECAC therefore have included not only Edison's revenue requirement for the ECAC forecast period, but also the development of the IER and ERI used in determining variable QF payments. As directed by D.87-12-066 and D.88-04-026 in Edison's most recent general rate case, revenue allocation, but not rate design, was also considered in this proceeding.

In reviewing these issues, we will first examine the method for determining revenue requirement and IERs. In this regard, Edison and DRA did not agree on the need for a common methodology to determine both revenue requirement and IERs.

The need to "re-run" any program or computer model based on our adopted forecast expenses and assumptions will also be examined. This discussion will be followed by an examination of the individual assumptions and ratemaking approaches at issue which directly affect not only the revenue requirement forecast for Edison, but, with respect to certain assumptions, variable QF payments as well. We will then examine the calculation of variable QF payments, including the recommended IERs and the stipulated ERI. The final section of this decision will address the issue of revenue allocation.

Before proceeding with our discussion, we wish to remark, as DRA has done in its brief, on the need for updates in an ECAC proceeding. There appeared to be some concern during the hearings regarding the updating of Edison's and DRA's final revenue requirement and IER recommendations. As stated by DRA in its

brief, however, every change in an expense number related to expected generation or resource availability requires the development of a new revenue requirement, a new IER, and new revenue allocation recommendations.

We concur with DRA's statements. Our effort in an ECAC proceeding is to reflect the most up-to-date data for any adopted forecast expense or IER. This effort, which protects the utility, its ratepayers, and QFs alike, becomes more critical when the requested relief will result in a significant rate increase, as is the case in this proceeding. As DRA points out, although both Edison's and DRA's current recommendations are far below Edison's original request of $628 million, ratepayers still face the possibility of a system average rate increase of 7.1% (based on DRA's $384 million) or 8.4% (based on Edison's $456 million). In authorizing such an increase, the Commission should be confident that the required revenue is based on the most recent data and reliable forecasting expertise. We therefore find that in this proceeding it was reasonable for Edison and DRA to update their recommendations.

C. Method for Determining Edison's Revenue Requirements and IER

The forecast used to develop Edison's revenue requirement is derived from the estimated production and expense levels related to hydro, coal, nuclear, purchased power, alternative/renewable power, and oil and gas resources. The forecasts of energy production and availability impact the determination of Edison's generating efficiency at the margin as measured by the IER.

In this proceeding Edison used its Fuel and Purchase Power (FPP) spreadsheet computer model to determine its forecast energy mix and expense for purposes of determining its revenue requirement and the ELFIN production cost computer model for determining its IER. In contrast to Edison, DRA used the ELFIN model to determine both its forecast of generation and expense, as well as its recommended IER. ELFIN was also chosen by the CCC/CSC

to provide their recommended IER. No party relied on a production cost computer model other than ELFIN to develop its recommended IER.

In this section, we will examine the arguments of Edison and DRA regarding the merits or need to use ELFIN to determine Edison's forecasted generation and expense, as well as its IER. Both Edison and DRA request that if the Commission adopts only certain specific components of either forecast, DRA and Edison be permitted to rerun either the FPP or ELFIN model to derive a revenue requirement.

1. Parties Positions

As stated previously, in this proceeding Edison used its FPP spreadsheet program to determine resource mix and average heat rates, and ELFIN to determine its IER used in QF energy payments. According to Edison, the FPP spreadsheet program uses a deterministic energy balance algorithm to calculate energy production for each resource or resource type. Edison states that the deterministic equations are based upon historical performance, forecast gas prices, hydro conditions, and known contractual obligations among other input. Once the resource mix and average heat rate for gas-fired units have been determined, the total revenue requirement may be calculated.

Edison believes that its FPP spreadsheet program is preferable to ELFIN due to its relative ease of use, ability to verify study results, historical accuracy, and stability of output. It was Edison's testimony that FPP results could be generated in a maximum of two days. Edison also notes that the Commission has relied on the FPP spreadsheet in determining Edison's revenue requirement in past Edison ECAC proceedings.

In contrast, Edison finds the following shortcomings in using ELFIN to derive its revenue requirement:

1. The time required to produce ELFIN results. Edison states that ELFIN results, produced only after multiple iterations,

reasonableness reviews, and extensive post-processing, are yielded only after several weeks.

2. ELFIN's need for modeler's judgment. Edison states that the reasonableness checks for each ELFIN iteration are largely dependent upon the modeler's judgment of how well the model mimics expected system operation.

3. ELFIN's inherent "lumpiness". Edison defines this phrase as referring to small changes in the input assumptions causing large and unpredictable changes in ELFIN results.

4. The propriety of using ELFIN in forecasting revenue requirement. According to Edison, for forecasts of one year or less production cost models such as PROMOD or ELFIN are no more appropriate or accurate than any other method. Edison also states that there is no requirement that ELFIN be used to determine both revenue requirement and IERs and that a model suitable for one purpose may not be suitable for another.

Edison notes that its use of ELFIN for developing IERs also does not indicate its acceptance of that model, but rather its need to respond in a timely fashion to the dictates of D.87-12-066.

Edison therefore urges the Commission to continue its reliance on Edison's FPP spreadsheet program for forecasting revenue requirement. In its brief, however, Edison does recognize the possibility of the Commission adopting ELFIN for forecasting revenue requirement, but relying upon input assumptions different from those used by DRA in its ELFIN run. Edison asks that under those circumstances Edison be given the opportunity to submit its own results of the ELFIN model or the FPP spreadsheet program or both based on the final adopted input assumptions. Edison believes that this process would be particularly useful in verifying ELFIN results.

It is DRA's opinion that for this ECAC the Commission should rely on ELFIN for both revenue requirements and IERs. DRA states that it is the only party to this proceeding that has presented a single, consistent set of integrated assumptions and conclusions that can be adopted by the Commission and used to determine both Edison's revenue requirement and IER in this proceeding.

In support of its position, DRA states that ECAC revenue requirements flow from a forecast of how the utility system will operate in the coming year. According to DRA, the most appropriate method to forecast system operation is a production cost model, such as ELFIN, that simulates system operation. DRA states that this simulation of system operation, not possible on a spreadsheet program such as Edison's FPP, reflects the dispatch of resources and optimization of system operation based on resources and load conditions expected during the forecast period.

DRA acknowledges that ELFIN may not be a perfect model of system operation, but asserts that it is a significant step beyond a spreadsheet program. According to DRA, at this time, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Sierra Pacific all use some type of production cost model to forecast their resource mix and revenue requirements.

DRA also argues that consistency requires the use of ELFIN to produce Edison's revenue requirement when it has been used exclusively by the parties to produce IER recommendations. In DRA's view, the Commission should not permit the use of different forecast resource mixes for different purposes in the same proceeding. DRA states that such an approach reduces the benefits of uniformity and efficiency that should result from using a combined proceeding to determine both revenue requirements and IERs.

In response to Edison's criticism of ELFIN, DRA cites Edison's own testimony indicating that ELFIN had produced

reasonable results in Edison's in-house attempts to develop a revenue requirement based on ELFIN. DRA further notes that a comparison of FPP and ELFIN results showed a maximum difference of 4% between those results.

DRA believes that Edison's main concern is its desire to verify the results of ELFIN if adopted. DRA believes that this concern can be adequately addressed in comments following the issuance of the ALJ's proposed decision. DRA suggests that comments be limited in scope to noting errors in entering the input assumptions or offering corrections to outputs that are demonstrably erroneous given the adopted input assumptions.

2. Discussion

In our effort to determine a meaningful and efficient way in which to update variable QF payments, we chose in D.88-03-026 to undertake those updates in the utilities' ECAC proceedings. In making this choice, we specifically rejected the use of an annual proceeding separate from ECAC as it "would not be orderly or administrable, nor would it properly integrate QF pricing within the regulatory framework." In particular, we found as follows:

> "If we were to require the use of ECAC assumptions in a subsequent single proceeding for QF pricing, QFs would appear in ECACs to litigate those assumptions, and the subsequent proceeding would have little point. If we were to update those assumptions in the later proceedings, we would have essentially a new ECAC proceeding, just for QFs, but involving all three major electric utilities." (D.88-03-026, at p. 3.)

We concluded that the "solution to this problem is not to create a unique proceeding for QFs, but rather to make optimal use of ECAC by setting QF prices at the same time (and from the same assumptions) that we adjust utility rates." (D.88-03-026, at p. 3.) For similar reasons, we rejected PG&E's proposed quarterly adjustment of IERs based on a narrower review of input assumptions than that performed in ECAC. In this regard, we found that

"selective updating, even where the assumptions to be updated are specified in advance, [seemed] susceptible to 'gaming' by the parties." (Id., at p. 4.) We also questioned whether the selected assumptions could fairly or reasonably be changed without re-examination of all other inputs.

This decision makes clear our intent to provide a consistent approach to the development of both a utility's rates and QF prices. A review of QF standard offer decisions reflects that this goal has long been embraced by the Commission to ensure accurate prices to QFs as well as ratepayer indifference to the source of a utility's power.

Edison is correct in stating that the propriety of using a production cost model or ELFIN in particular for developing IERs may not necessarily extend to forecasting revenue requirement. Edison is also correct in stating that its FPP program was used to develop its revenue requirement in its 1987 ECAC proceeding.

Reliance on these factors by Edison to support its continued use of the FPP spreadsheet, however, ignores changes in this Commission's and other utilities' approaches to ECAC proceedings. Specifically, Edison's most recent ECAC did not consider the updating of the utility's IER or ERI used in variable QF payments. Further, as DRA notes, both PG&E and SDG&E have chosen to use a production cost model, namely PROMOD, in forecasting resource mix and revenue requirements in their most recent ECAC proceedings.

In PG&E's current ECAC (A.88-04-057), PG&E states in Exhibit 1 at page 3-3 that "[f]orecast area loads as well as forecasts of the various resource availabilities and prices are input to PROMOD along with data pertaining to electric system reserve and reliability requirements, operating constraints, and contractual requirements." PG&E's approach seems to recognize that the simulation of system operation provided by a production cost

model is as necessary to determining IERs as it is to developing the resource mix in forecasting revenue requirement.

Embracing the computer age should also not be a selective process. While Edison may have had questions about ELFIN, the requirement that it use ELFIN in this proceeding was limited to using that model to produce a base case run for the IER calculation. Edison was free, however, to rely on a different, preferred computer model on which to base its revenue requirement or IER recommendations. We are aware that Edison owns PROMOD and has consistently relied on its results in other rate and standard offer proceedings, including its most recent general rate case.

It should be clear to Edison, following our issuance of D.87-12-066 and D.88-03-026, that it is our goal to ensure that updates and forecasts of a utility's resource mix and expense, IERs, and ERIs are made on a consistent and uniform basis. Such consistency not only "integrate[s] QF pricing within the regulatory framework", but assures that we are "setting QF prices at the same time (and <u>from the same assumptions</u>) that we adjust utility rates." (D.88-03-026, at p. 3, emphasis added.)

As we stated in D.88-03-026, this approach also alleviates any possible "gaming" by the parties. In this regard, we note that the times of traditional ECAC participation being limited to the utility and DRA are behind the Commission. Instead, we face an era when ECAC issues have extended to include not only QFs, but also interested parties concerned with rate design and revenue allocation.

In our review of the arguments presented by Edison regarding ELFIN, we find Edison's misgivings center for the most part on the efficiency of using ELFIN. We do not find in those arguments, or for that matter Edison's discussion of the specific assumptions, any evidence that ELFIN produces unreasonable forecast results or results substantially at odds with the FPP spreadsheet program. Further, the use of the production cost model to forecast

both revenue requirements and the components of variable QF payments best achieves our regulatory goal of consistency in the development of utility rates and QF prices, reflects the growing reliance on computer modeling in ratemaking, and ensures consistent results. The fact that ELFIN is the sole model upon which we can rely is merely a circumstance of this particular ECAC, and one which the parties need not repeat in Edison's next ECAC.

For these reasons, we will adopt DRA's recommendation to use ELFIN to develop both Edison's revenue requirement and IERs. With respect to updating the revenue requirement during the comment period following the issuance of this proposed decision, we find that it will not be necessary for Edison to "re-run" its FPP spreadsheet or develop a new ELFIN run.

Specifically, we note that Edison's and DRA's most significant disagreement on forecast assumptions centered on the forecasted gas price. Both parties agreed that this difference was in turn largely responsible for differences in their other forecast recommendations.

As reflected in the following discussion, we have adopted DRA's forecasted gas price and, in turn, most of DRA's other revenue requirement recommendations. Under these circumstances, it is necessary only for DRA, and not Edison, to "re-run" the ELFIN model in the comment period and present its results as a late-filed exhibit. Even if DRA's recommendations had not been adopted, we still do not believe it would have been appropriate for Edison to "run" ELFIN for the first time or present its FPP spreadsheet again during the comment period to produce a revenue requirement. If we permitted Edison to take such a step, we would be allowing Edison to present a revenue requirement methodology which either it had never presented during hearings (ELFIN) or the Commission had rejected (FPP spreadsheet).

In contrast, DRA has already presented, and had subject to cross-examination, its approach to developing Edison's revenue

requirement. Though Edison expressed misgivings about ELFIN itself, Edison presented no significant challenges or objections to the way in which DRA ran the model or applied its judgment to any post-processing required to obtain reasonable results.

In the case of the IER, we note that we did not uniformly adopt the assumptions of any single party. This circumstance therefore necessitates the parties "re-running" ELFIN during the comment period and presenting their final recommendations as late-filed exhibits. The parties making ELFIN runs during the comment period to develop final revenue requirement (DRA) or IER (Edison, DRA, and CCC/CSC) recommendations will be required to serve each other with all supporting work papers at the same time their comments are filed.

It is our hope that, with the use of the same model and adopted assumptions, the IER results produced by the parties will not vary greatly. We also believe that our adopted procedure for considering these results, necessitated by time constraints in this proceeding, is appropriate since all parties have used the same model and now the same assumptions. Additionally, each party has had an equal opportunity through many days of workshops and hearing to discuss and cross-examine each party's use of ELFIN.

We note that consideration of final revenue requirement and IER recommendations in the comment period following the issuance of the ALJ proposed decision may not ultimately be the preferred method of litigating ECAC assumptions and results. As DRA has stated in its brief, however, this forecast period is in effect for only one year and, like any forecast, is marked by some uncertainty. To meet legitimate regulatory goals in a timely fashion, we believe that it is inappropriate to lengthen this ECAC forecast phase unnecessarily.

Specifically, we note that meeting a mid-September issuance date for the final decision in the forecast phase is critical to assure that the IER and ERI adopted in this decision

will be reflected in the QF price filings to be made by the utilities on November 1, 1988. (D.88-03-026, at p. 6.) Failure to meet this deadline means that QF prices adopted for this forecast period could not go into effect until February, 1988, a period just short of the commencement of Edison's next forecast period. Such a result defeats the purpose of the updating contemplated by D.88-03-026.

It is our hope with the parties will have sufficiently adjusted to new ECAC issues and procedures this year to result in greater efficiency in completing the 1989 ECAC. This effort should be aided by changes to ECAC time schedules being reviewed by the Commission in Rulemaking (R.) 87-11-012.

D. Forecast of Energy Expense and Resource Mix

In this section we will examine the parties' recommended forecasts of energy expense and resource mix. Certain of these forecasts impact Edison's revenue requirement only, while others impact both revenue requirement and IER recommendations. The majority of the issues were addressed only by Edison and DRA with the CCC/CSC focusing on those issues, including gas dispatch price and resource mix, directly related to the determination of Edison's IER.

In reviewing assumptions related to the development of Edison's IER, we wish to note the value of the IER workshops which preceded hearings in this proceeding. These workshops enabled parties to achieve a timely exchange of data and to clearly identify those issues upon which agreement could not be reached. Such a result is not a minor, but a significant achievement, especially in a proceeding which must be heard in a limited time. We appreciate the efforts of all of the parties in participating in this workshop and encourage the continued use of this forum to enhance the efficiency and value of the ECAC hearing process.

The following table excerpted from DRA's late-filed Exhibit 77, submitted on June 22, 1988, provides a comparison of Edison's and DRA's forecast revenue requirements absent consideration of the interim rate relief granted on May 25, 1988. This table reflects differences between Edison and DRA on the following issues: (1) natural gas generation and expense, (2) oil generation and expense, (3) purchased power generation and expense, (4) coal generation and expense, (5) fuel oil inventory carrying costs, and (6) franchise fees and uncollectible accounts expense and resale accounts allocation.

Comparison of DRA and SCE ECAC Revenue Requirement Prior to Interim Rate Relief
Update Based on April 1, 1988 Snow Survey; Revised June 1988
($ Thousands)

Ln	Item Description	DRA 5/ (a)	SCE 6/ (b)	SCE > DRA (c) = (b)-(a)	Percent Diff. (c)/(a)
1	Oil	$24,837	$48,143	$23,306	93.8%
2	Gas	613,251	628,991	15,740	2.6%
3	Coal	108,720	108,968	248	0.2%
4	Nuclear	165,052	165,052	0	0.0%
5	Purchased Power	1,267,557	1,300,728	33,171	2.6%
6	Less: Off-System Sales	19,067	20,996	1,929	10.1%
7	Subtotal	2,160,350	2,230,886	70,536	3.3%
8	Less: Resale	12,523	12,932	409	3.3%
9	Total Subject to ECABF	2,147,827	2,217,954	70,127	3.3%
10	Less: 10 percent AER	214,783	221,795	7,012	3.3%
11	Subtotal Energy Expenses	1,933,044	1,996,159	63,115	3.3%
12	Plus: Fuel Oil Inventory	5,626	6,938	1,312	23.3%
13	Carrying Costs				
14	Coal Inv. C.C.	686	649	(37)	-5.4%
15	Nuclear Fuel C.C.	25,229	25,384	155	0.6%
16	Subtotal	1,964,585	2,029,130	64,545	3.3%
17	Plus: Fr. Fees & Uncoll.	18,722	19,338	615	3.3%
18	ECAC Fuel & P.P. Costs	1,983,308	2,048,468	65,160	3.3%
19	Est ECAC Bal. at 6/1/88 1/	(89,491)	(89,491)	0	0.0%
20	Plus: Fr. Fees & Uncoll.	(853)	(853)	0	0.0%
21	Subtotal	1,892,964	1,958,124	65,160	3.4%
22	Plus: LSFO Write-down	54,862	54,862	0	0.0%
23	Dist. Write-down	4,572	4,572	0	0.0%
24	Chevron Settle.	204,427	204,427	0	0.0%
25	Uran. Contr. Term.	77,722	77,722	0	0.0%
26	Total ECAC Rev. Req.	2,234,547	2,299,707	65,160	2.9%
27	Present ECAC Revenue 2/	1,845,000	1,845,000	0	0.0%
28	Change in ECAC Rev. Req.	389,547	454,707	65,160	16.7%
29	Sales (gWh)	65,312	65,312	0	0.0%
30	Pres. ECAC Rate (c/kWh) 3/	2.825	2.825	0.000	0.0%
31	Proposed Rate (c/kWh) 4/	3.421	3.521	0.100	2.9%
32	Rate Change (c/kWh)	0.596	0.696	0.100	16.7%

1/ From Exhibit 39.
2/ From Exhibit 52.
3/ Line 27 divided by line 28.
4/ Line 26 divided by line 29.
5/ Reflects updated CA hydro and PNW forecast from Exh. 66, and TRT pp.174-176.
6/ Reflects hydro and coal expense corrections shown in TRT pp.27 and 5RT pp. 467-469. Related expense changes translated into rev. rqmts. based on a 6/8/88 data transmittal from SCE to DRA.

The parties did reach agreement on the (1) sales forecast, (2) Edison hydro generation, (3) nuclear generation and expense, and (4) the estimated ECAC and ERAM account balances. The following summarizes those areas of agreement:

1. Sales Forecast. DRA agrees with Edison's net sales projection of 1,003 million KWh.

2. Edison Hydro Generation. DRA agrees with Edison's forecasted total hydro production of 3,327 gW and the results of the April 1, 1988, snow survey.

3. Nuclear Generation and Expense. DRA and Edison agree on the forecasted nuclear generation and expense with the exception of a minor difference in energy production due to ELFIN dispatch. DRA concurs with Edison's request that, in order for such expenses to receive consistent ratemaking treatment, the uranium portion of nuclear fuel expenses be subject to the ECABF/AER percentage allocation.

   In addition, DRA and Edison agree that 25 basis points should be added to the appropriate interest rate for financing issuance costs in calculating in-core nuclear fuel inventory carrying costs. DRA has no objection to Edison financing its in-core nuclear fuel with a mixture of short-term and intermediate term debt. DRA agreed that if Edison issues intermediate term debt financing for nuclear fuel, the forecast should reflect the intermediate-term debt.

4. Estimated ECAC and ERAM Balancing Accounts. DRA agrees with Edison's estimated June 1, 1988, ECAC Balancing Account balance. DRA and Edison agree on the estimated June 1, 1988, ERAM Balancing Account balance and resultant ERAM revenue change for a June 1, 1988 Revision Date.

We find that the areas of agreement between Edison and DRA are reasonable and should be adopted. With respect to disputed

issues, the difference between Edison's and DRA's revenue requirement recommendations is largely attributable to the difference in their gas price forecasts and the effect such forecasts have on the quantity and price of Edison's power purchases.

Before examining the contested issues, we note that Edison proposes a temporary suspension of the AER in June, 1989. Edison states that such a suspension is necessary if the Commission decides in R.87-11-012 (the Commission's general rate case and fuel offset scheduling rulemaking) to change Edison's annual ECAC revision date from June 1, 1989, to a later date. If the AER is not suspended, Edison believes that ratepayers and shareholders will be at risk for differences between recorded and forecast AER revenues and expenses.

In response to this request, we reiterate our commitment to the reinstitution of an AER for Edison and will adopt a 10% AER for Edison's current forecast period. Although we acknowledge our temporary suspension of Edison's AER in this ECAC in D.88-05-074, we note that certain specific circumstances existing at that time dictated our action. Specifically, this suspension was required, among other things, due to delays in this proceeding caused by the addition of issues new to this ECAC and the significant rate increase requested by Edison.

Under these circumstances, we believe that it would be premature to grant the suspension of Edison's AER beginning June 1, 1989, based solely on the possibility of an ECAC schedule being adopted for Edison in R.87-11-012 that varies from Edison's current schedule. Suspension at this time for the 1989 ECAC would also suggest that the AER is not a permanent part of Edison's ECAC structure, but one which can be altered or removed at will.

We find that this result was clearly not one intended by D.87-11-013. By that order, we sought to reimpose the AER to "provide an incentive to the utility's management to reduce its

fuel and purchased power expenses and to have a direct stake in its fuel management decisions." (D.87-11-013, at p. 11.) This goal cannot be realized if the AER becomes only a seasonal rate or one applicable only to a certain portion of the ECAC period. We therefore deny Edison's request and suggest that Edison renew its request only when and if circumstances warranting its suspension actually exist.

1. **Forecast of Fuel and Purchased Power Generation and Expense**

a. **Gas Generation Expense**

The forecast price of gas not only determines the cost of running many of Edison's own resources, but is also used in forecasting economy energy quantities and prices and in determining QF payments. The DRA forecast of gas generation is approximately $16 million less than that forecasted by Edison. This difference stems from differences in the parties' forecasts of the spot gas price, oil burn, and quantity of purchased power resulting from the parties' different forecast gas prices.

It is Edison's opinion that it effectively demonstrated that gas prices likely to occur during the forecast period are going to be higher than those forecast by DRA. According to Edison, its forecast was based on the following factors: (1) recent historical prices paid by Edison for spot gas prices, (2) the continuance of seasonal price trends in which winter prices are higher than summer prices, (3) the decrease in the national gas deliverability surplus, (4) the current gas production selling at prices below the cost to develop new gas reserves, and (5) the increased likelihood of winter gas curtailment to the Utility Electric Generation (UEG) market. Edison further states that its forecasted increase in the spot market price of natural gas represents only an increase of 6% in comparison with the most recent 12 months of experience.

According to Edison, its forecast reflects industry experts' opinions and present market conditions. This analysis includes a reasonable projection of an increased gas requirement by Edison due to dry hydro conditions and longer gas curtailments of the UEG market due to higher gas demand.

While not a part of the evidentiary record in this proceeding, Edison also requests that the Commission take official notice of a recent Federal Energy Regulatory Commission (FERC) filing by El Paso Natural Gas Company (El Paso). This filing requests significant increases in the transportation price for gas to the California/Arizona border. (Docket RP 88-44 (May 31, 1988).) Edison states that the proposed new gas price, potentially effective as soon as July 1, 1988, would cause the transportation rate and the price of spot gas to increase, on average, by 40 cents to 50 cents per million Btu.

With respect to the its forecast spot market gas price, Edison notes that there is essentially no difference in Edison's and DRA's forecasts for the first six months of the forecast period. Edison urges recognition, however, of an increase in the spot market price for the December 1988 to May 1989 forecast period greater than that forecast by DRA. In support of its position, Edison points to the prolonged gas curtailment during December 1987 through February 1988. Edison believes that, based on its curtailment during three of the last four winters, seasonal curtailment is highly probable despite overall annual gas supply adequacy. For the spring period, Edison states that its May 1989 price represents only a conservative 20 cent per million Btu increase over the forecasted June 1988 price.

Edison objects to DRA's assertion that DRA's forecast is more reliable than Edison's forecast due to DRA's greater accuracy in predicting actual prices in Edison's prior ECAC. Edison states that the accuracy of one particular forecast is insufficient to prove that a methodology is reliable and reasonable. Edison

therefore asks that the reasonableness of its forecast in this proceeding be judged in the context of the regulatory and market circumstances that currently exist, not upon prior forecast accuracy.

As described by DRA, its forecast gas price was based on three components. These components included: (1) the UEG transportation and demand charges based on recent advice letter filings by Southern California Gas Company (SoCal) and PG&E in response to D.87-12-039, (2) commodity costs for gas supplies purchased from SoCal based on the estimated SoCal border price for gas, and (3) the P5 or bulk burn price based on DRA's estimated mix of SoCal Tier II volumes and Edison's independently obtained spot supplies.

In explaining its approach, DRA states that the Tier II price of gas is the key determinant of DRA's forecast of the dispatch price of gas. According to DRA, the dispatch price is used in making economic choices about what energy sources to utilize in system operation. DRA determined the dispatch gas price by weighting the price of expected spot gas purchases from SoCal Gas and the price of purchases from other sources during the forecast period. DRA asserts that Edison's recent spot gas purchasing history and the major changes that flow from the unbundling of the gas market support DRA's projection that Edison will purchase 60% of its spot gas from SoCal Gas and 40% from other sources. DRA priced this independently procured gas at 96% of the Tier II price. DRA states that this method of forecasting the dispatch price was not challenged by Edison in either its cross-examination of DRA's witness or in Edison's brief.

In further support of its showing, DRA states that testimony in this proceeding shows that the recorded average spot gas price for the 1987 ECAC period was $1.86. DRA's average forecast gas price for the 1988 ECAC period is $1.87, a level slightly higher than the previous forecast period. In contrast,

DRA notes that Edison's $2.04 annual average represents an approximate 9% increase over last year's recorded average.

Additionally, DRA states that its gas price forecast appropriately reflects seasonal variations, with prices approximately 20 cents higher in the winter time. DRA notes that its witness stated on cross-examination that if he were to alter his forecast to reflect current conditions, he would lower the June and July 1988 prices by 10 to 15 cents. This circumstance reflects, in DRA's view, that its forecast is actually somewhat conservative. DRA also notes that the actual spot gas prices in April and May of 1988 went below any of the 1987 ECAC forecasts for May 1988 and below the Summer 1988 forecast for the 1988 ECAC by both Edison and DRA.

In support of the accuracy of its forecast, DRA states that, in the first nine months of the last ECAC period, its witness's forecast was within $0.04/MMBtu of the weighted average ECAC price based on Edison's actual spot purchases. This forecast was also within $0.05/MMBtu of the weighted average ECAC price based on Edison's actual total gas purchases. In contrast, DRA states that Edison's forecast errors were nearly double DRA's. Based on these circumstances, DRA asserts that its methodology and recommendations have proven to be reliable and reasonable.

DRA objects to Edison's methodology for its selective use of its consultants' forecasts. DRA states that in forecasting oil prices, Edison used the arithmetic average of the forecasts of the three consulting firms which it retained. For its gas price forecast, however, DRA notes that Edison used the arithmetic average of only the two highest of the three forecasts produced by these firms. For its updated gas price forecast, DRA states that Edison's witness chose to rely on none of the retained firms, and chose instead to rely on the published reports of other experts.

DRA also argues that the evidence in this proceeding does not support Edison's claim of severe UEG gas curtailments during

the winter. DRA believes that the circumstances leading to the lengthy gas curtailment during last winter, including an unusual cold spell, structural changes in the gas industry, and unusual storage problems on the SoCal Gas system, are unlikely to reoccur this winter. DRA further notes that its gas price forecast takes into account DRA's forecast 15-day curtailment period.

Finally, DRA rejects Edison's reliance on the recent El Paso filing with FERC. DRA believes that Edison jumps too quickly to the gloomy conclusion that the result of this filing will be to increase the price of spot gas by 40 to 50 cents per million Btu. Even assuming that FERC approves this prices increase, DRA states that its effect on Edison's gas prices is a matter of pure speculation. In practice, DRA states that El Paso may charge some, all, or none of that increased authorized transportation rate.

CCC/CSC supports DRA's modeling of the dispatch gas price. CCC/CSC states that Edison has offered no basis for rejecting DRA's forecast. Additionally, in CCC/CSC's opinion, Edison showed a systematic disregard of its own experts reflected finally in a forecast update which relied on none of those experts.

CCC/CSC also objects to Edison's reliance on the El Paso filing. CCC/CSC asserts that this filing has not been the subject of any meaningful review in this proceeding nor has yet to be adjudicated.

We find DRA's arguments in support of its gas price forecast to be persuasive. Inconsistencies in Edison's forecast approach, as well as an exaggerated response to seasonal curtailments, undermine the reliability of Edison's forecast. Further discussion of the parties' estimates of gas curtailment are included in the following section on oil generation expense.

Based on our review of the record, we find that DRA has examined all of the elements necessary to provide a reasonable gas price forecast and in turn a reasonable level of gas generation expense. DRA has appropriately considered recorded data and made

allowances for seasonal variations in gas prices. We also concur with DRA and the CCC/CSC that reliance on the El Paso filing is premature and that its impact on gas prices can not yet be quantified.

Finally, while DRA's accuracy in forecasting last year's gas price is alone not sufficient to adopt its current forecast, it does act as further support of the experience of the forecaster and the soundness of the methodology. We therefore find reasonable and adopt DRA's forecast of Edison's gas generation expense.

b. Oil Generation Expense

Edison's oil generation expense depends primarily on estimates of two factors: the quantity of oil expected to be consumed and the replacement cost of the oil. In this proceeding, Edison and DRA offer different forecasts of both these factors. Their estimates of the quantity of low sulfur fuel oil (LSFO) expected to be burned during the forecast period differs primarily as a result of different forecasted gas curtailment.

Edison estimates 1.5 million barrels of LSFO burn due to gas curtailment, while DRA estimates 390,000 barrels of burn. The price per barrel of LSFO is forecast at $20.05 per barrel by Edison and $18.23 per barrel by DRA. Based on these estimates, Edison forecasts a level of oil generation expense at $48.1 million while DRA recommends an expense level of $24.2 million.

Edison states that its estimate of LSFO burn is based upon Edison's most recent historical experience and Edison's judgment as to the potential effect recent market and regulatory changes will have on the amount of gas available to Edison. Edison believes that its 1.5 million barrel estimate is reasonable following a winter where 1.2 million barrels of LSFO were burned. Edison notes that last winter's LSFO burn would have been greater had Edison not been able to purchase an unanticipated amount of firm electric energy.

With respect to LSFO prices, Edison states that it based its forecast on a consensus forecast of low sulfur waxy residue (LSWR) prices which was used as a proxy for the price of LSFO to Edison. Edison states that it obtained LSWR price forecasts from three industry experts, each with a knowledge of the market forces affecting low sulfur oil. Each consultant's LSWR price forecast was then reviewed for reasonableness by Edison and was weighted equally in Edison's consensus forecast.

Edison believes that DRA erred in its forecast by multiplying the 1984-86 gas curtailment data by the 1987-88 oil burn rate. According to Edison, this approach mismatches the burn rate and curtailment days from different time periods and should be rejected.

DRA states that the issues of forecasted oil burn and gas curtailment are intertwined. In making its recommendation DRA states that it accepted all of Edison's LSFO oil burn figures except the amount of oil to be burned during November, December, and January. In those months, Edison predicts 1.58 million barrels will be burned, while DRA forecasts that only 470,200 barrels of LSFO will be burned.

DRA states that its estimate is based on two factors: (1) a forecast of 15 days of gas curtailment in the forecast period, which is multiplied by (2) a forecast daily oil burn rate of 26,000 barrels. DRA's forecast of 15 days of gas curtailment is based on the 1987 California Gas Report as well as information supplied by SoCal Gas, Edison's chief supplier. As noted in the previous section on gas generation expense, DRA believes that, despite the severe curtailment last winter, the circumstances causing that curtailment (i.e., unusual cold snap coupled with SoCal's extraordinary storage problems) are unlikely to be repeated. DRA also notes that, based on a 5-year average including last winter's curtailment, only an 18 day curtailment would result.

DRA notes that Edison did not provide its estimated days of curtailment. DRA found, however, that, in applying methodology to Edison's oil burn forecast, Edison was predicting about 59 days of curtailment. DRA asserts that this period is well beyond even the unusual six weeks of curtailment Edison experienced last winter.

DRA disputes Edison's assertion that it is inappropriate to pair a curtailment period derived from historical data with a burn rate derived from current data. In DRA's opinion, the best forecast of curtailment does not rely on a single curtailment period, but includes some historical average adjusted if necessary to reflect current conditions. DRA states that it therefore appropriately relied on the burn rate that most closely matched the generation units that were likely to be generating next year. Following this approach, the appropriate burn rate was the most recent burn rate.

According to its testimony, DRA made its own independent forecast of oil prices for the forecast period. DRA's forecast of fuel oil price is based on its estimate of LSWR prices and marine transportation rates. DRA believes that its LSWR price forecast compares favorably with the range of prices forecast by the federal government.

In reviewing Edison's and DRA's forecasts, we note that it is our intention to maintain consistency in the forecasts of both gas and oil expenses with respect to all common components. In this case, the issue of the estimated period of gas curtailment impacts both gas and oil generation expenses. As we stated earlier, we find that DRA has made reasonable assumptions concerning the level of curtailment which Edison can anticipate this winter.

Specifically, we share DRA's conclusion that factors leading to last winter's severe curtailment should be non-repeating this year. Even including consideration of last year's

curtailment, however, we find that DRA has demonstrated that the maximum curtailment period would be 18 days. We find, therefore, that under these circumstances the 15-day curtailment period forecast by DRA is reasonable.

With respect to LSFO oil prices, we again find DRA's testimony to be persuasive. DRA's independent forecast was well-supported and is not dramatically different from that asserted by Edison. Having adopted DRA's estimates of the two components determining oil generation expense, we therefore adopt DRA's forecast of $24.8 million for the forecast period.

c. Purchased Power Generation and Expense

Edison and DRA differed in their forecasts of purchased power generation and expenses by approximately $33 million. This difference is largely attributable to differences in their forecast gas prices. CCC/CSC, however, took issue with the approaches used by both Edison and DRA in forecasting economy energy availability.

(1) QF Purchases and Expense

With respect to the quantity of QF power estimated for this forecast period, DRA and Edison eventually agreed to a level of 14,446 Gigawatt-hours (gWh) for the forecast period. On the issue of the capacities projected for four large QF projects, DRA and Edison reached a compromise between their original estimates. CCC/CSC remained supportive of Edison's original projections of capacity factors for the four QF facilities, but neither provided nor cited any evidence in support of this position.

Based on the record, we find the agreement between DRA and Edison related to the quantity of QF power and the capacity factors projected for the four large QF projects to be a reasonable compromise of the forecasts presented. We therefore adopt the stipulated quantity and capacity factors.

Despite this agreement between Edison and DRA, in its brief DRA recites its concerns with Edison's record-keeping related to the level of QF generation. Specifically, DRA states that due to the size of this expense item, approximately 40% of Edison's total forecast energy expenses, DRA closely examined the assumptions underlying Edison's forecast of QF generation. DRA states that its witness found that in this proceeding, as in other recent Edison ECAC proceedings, Edison had failed to adequately determine the status of QFs not on line. DRA also states that reliable information about individual QF projects was difficult to obtain.

Of particular concern to DRA was that Edison had no written record of each QF contract nor a systematic method of keeping a record of their status. Specifically, DRA found discrepancies in the dates of operation assumed by Edison and the actual operating dates expected by the QFs.

Based on this history, DRA had originally recommended in this proceeding that Edison be required "to provide all QFs with a written data request regarding [their] operational data and to make such data available to DRA with its ECAC data response each year." (Exhibit 23, at p. 11-9.) In its testimony, DRA had included an outline of and timetable for the survey to be provided to QFs. Because of Edison's agreement during this proceeding to work with DRA to develop a mutually acceptable survey, however, DRA concluded that a Commission order on this issue was no longer necessary.

While we applaud both DRA's insistence on improving Edison's QF record-keeping and Edison's agreement to work with DRA to meet this goal, we, unlike DRA, believe that such a requirement should be embodied in a Commission order. To protect Edison's ratepayers and ensure accurate representation of QFs in Edison's resource mix, we believe that it is necessary to specifically

direct the completion of DRA's proposed survey by Edison's next ECAC. Such an order will therefore be included in this decision.

(2) Firm Purchases and Expenses

DRA and Edison agree on purchased power quantities from SCE Hoover, Mexico geothermal, Pacific Northwest firm purchases, California, SCE-renewable/alternative sources, and PURPA purchases. DRA forecast slightly lower Cholla generation (34 gWh) due to ELFIN dispatch. Edison's and DRA's forecasts of firm purchased power expenses differed due to the difference in forecast Cholla generation and the impact of different gas price forecasts on Pacific Northwest firm purchase contracts and PURPA expenses. DRA forecasts approximately $12.5 million less PURPA expense than Edison due to its lower gas price forecast and lower IER.

As previous discussion has made clear, we have adopted DRA's gas price forecast and approved DRA's use of ELFIN for determining revenue requirement. Given those circumstances, we find that the final firm purchase power expense level should be closer to that forecasted by DRA than by Edison. The final IER figure which we will adopt in this proceeding, however, may not mirror DRA's because of assumptions which we have adopted in this decision (infra) which differ from DRA's. For this reason, DRA will be required to re-examine this forecast to determine the change in revenue impact, if any, caused by any change in its IER value resulting from the assumptions adopted in this decision. This change should be reflected in DRA's ELFIN run undertaken during the comment period to develop Edison's final revenue requirement.

(3) Non-Firm Purchases and Expenses

The determination of non-firm purchases and expenses are based on forecasts of Pacific Northwest (PNW) and Pacific Southwest (PSW) economy energy availability and cost. In developing the prices for PNW and PSW economy energy, DRA and Edison agreed to an algorithm that describes the relationship

between the natural gas price and the expected quantity of energy that would be purchased. In making its recommendation, Edison relied solely upon the algorithm as set forth in Exhibit 37, while DRA used the result of the algorithm as an input to ELFIN and relied upon the resulting ELFIN output.

In addition to DRA and Edison, the CCC/CSC participated on the issue of PNW economy energy availability. The CCC/CSC made its own evaluation of this availability.

(i) Pacific Northwest Economy Energy

DRA and Edison agree on the quantity of PNW economy energy purchases. These parties also agree that the quantity of energy available from the Pacific Northwest should be capped to reflect a dry hydro year. The difference in Edison's and DRA's forecast of PNW non-firm purchased power quantity and expense is due solely to the impact of the differences in DRA's and Edison's gas price forecasts. For PNW power, the parties believe that the algorithm contained in Exhibit 37 and DRA's ELFIN run should produce the same results once the same gas price forecast is used.

CCC/CSC disputes the availability of PNW economy forecasted by DRA and Edison. CCC/CSC notes that DRA and Edison have projected a three-month period of economy energy availability, while CCC/CSC forecasts that PNW economy energy will be unavailable for a seven month period from June 1988 through January 1989. CCC/CSC argues that its evaluation of PNW economy energy availability is based on an expert understanding of both the operating requirements and current conditions in the Pacific Northwest. In contrast, CCC/CSC finds the substance of DRA's and Edison's algorithm to be that the "present will be reflective of the past." (Exhibit 32, at p. 40.)

In reviewing the record on this issue, we are not convinced that CCC/CSC has adequately demonstrated that a seven-month period of zero-availability of economy energy power is

likely to occur. Neither do we find that CCC/CSC demonstrated that the algorithm relied upon by DRA and Edison was seriously flawed. We find, under these circumstances, that the three-month period of zero-availability projected by DRA and Edison is a more reasonable forecast of future availability of PNW power.

Given our adoption of DRA's forecast gas price and use of ELFIN to develop Edison's revenue requirement, we find DRA's forecast of PNW economy energy availability and expense to be reasonable. The record does not support rejection of either the algorithm relied upon by Edison and DRA or its use in the ELFIN model.

(ii) Pacific Southwest Economy Energy

DRA and Edison differ on both forecast quantity and expenses for Pacific Southwest purchases. The difference in price is again due to a difference in gas price forecasts. The parties agree, however, that the difference in forecasted quantity would not be great if the same gas price forecast were used. CCC/CSC disagrees with DRA's and Edison's approaches for their failure to impose a ceiling on PSW economy energy availability.

According to CCC/CSC, the algorithm developed by Edison is designed to determine the amount of PSW economy energy which can reasonably be expected at various gas and fuel prices. CCC/CSC states that the formula, based upon historical data, was developed in theory as a basis for determining the ceiling level of PSW economy purchases which the ELFIN model could "take" in its determination of available resources.

CCC/CSC adopted the Edison regression formula as the basis for determining the ceiling for PSW availability. However, CCC/CSC asserts, however, that a review of the Edison and DRA base case ELFIN runs reveal that neither party maintained the ceilings resulting from this formula. CCC/CSC states that reflecting availability in excess of the regression ceiling is to

suggest that the system can purchase power at a favorable price when the regression formula indicates that such power does not exist.

CCC/CSC also is concerned that while DRA alternatively embraced and repudiated the regression formula, it preferred to let ELFIN model the availability of PSW. CCC/CSC states that DRA apparently supported their ELFIN "QF-Out" takes of PSW economy because they were relatively close to the regression's results. CCC/CSC argues, however, that DRA's final base case recommendation revealed a dramatic difference between the regression at the DRA gas price and the ELFIN model output--2,329 gWh versus 2,688 gWh.

Edison states that it attempted to model PSW economy energy to reflect market-determined incremental cost conditions and then permitted ELFIN to determine the quantity of PSW economy energy "to take" based on economics. In contrast, Edison asserts that CCC/CSC's imposition of a ceiling has the effect of "hardwiring" the model so that it takes as much PSW economy energy as the regression equations imply. Edison believes that CCC/CSC has offered little support for pegging the price of PSW economy energy in each month to be exactly proportional to the dispatch price of gas. Edison believes that its approach is more appropriate, especially given concerns expressed about "hardwiring" during the workshops preceding hearings in this proceeding.

DRA objects to CCC/CSC's claim that DRA's ELFIN-generated results are in error because DRA's "QF-Out" ELFIN run (2688 gWh) differed from the PSW algorithm result of 2329 gWh. DRA believes a more appropriate comparison would be between the algorithm and DRA's updated "QF-In" run. DRA notes that its updated "QF In" run (2401 gWh) resulted in only a 72 gWh difference from the PSW purchases (2329 gWh) predicted by the algorithm. Furthermore, DRA states that its PSW purchase forecasts are well within the benchmark range of 3000 to 3200 gWh identified by DRA

witness Lafrenz as a test of the reasonableness of the ELFIN modeling results.

Based on our adoption of DRA's gas price forecast and the use of the ELFIN model to develop Edison's revenue requirements, we find reasonable DRA's forecast of PSW economy energy availability and expense. The apparent small difference in quantity between ELFIN and use of the algorithm alone do not suggest flaws in either methodology.

We do not share, however, CCC/CSC's insistence on a ceiling for PSW economy energy availability. Specifically, we do not find sufficient support in this record for adopting such an approach at this time. We suggest, however, that the parties continue to explore the efficacy of "hardwiring" the ELFIN model in the IER workshops held in future ECACs.

We note that CCC/CSC's request for a ceiling on PSW economy energy availability is part of its overall argument for "audit controls" on ELFIN results. This argument is discussed at greater length in our review of QF payment issues.

d. Coal Generation and Expense

Edison's and DRA's forecast of coal generation and expense are very close, separated by a difference of only $248,000. This minor difference is attributable to different gas prices and ELFIN dispatch of Mohave. Given our adoption of DRA's forecast gas price and DRA's use of ELFIN to determine Edison's revenue requirement, we find reasonable DRA's forecast of coal generation and expense.

Edison and DRA also agree on the recommended coal inventory level for the forecast period. In addition DRA and Edison agree that coal inventory carrying costs should be calculated using the latest DRI forecast of three-month commercial paper rates plus 25 basis points. Edison's and DRA's agreement on these issues is reasonable and should be adopted.

2. Fuel Inventory Levels, Carrying Costs, and Ratemaking Treatment

a. Fuel Oil Inventory

(1) Fuel Oil Inventory Level

Edison and DRA forecast oil inventory levels of 6.3 million barrels and 4.4 million barrels respectively. Specifically, Edison and DRA agree on a dead storage inventory requirement of 1.0 million barrels, but differ on station inventory requirement and system inventory requirement.

The station inventory requirement refers to the amount of oil necessary to maintain adequate distribution logistics for Edison's oil pipeline, storage, and receiving facilities. The system inventory requirement is composed of (1) displacement oil, required for supporting oil movement through the pipelines, (2) oil required to float tank roofs, and (3) potential oil burn (POB), that component of oil inventory needed to meet forecast oil burn requirements prior to replenishment. For station inventory requirement, Edison forecasts a level of 2.0 million barrels, while DRA forecasts 1.5 million barrels. With respect to system inventory requirement, Edison forecasts 3.3 million barrels and DRA forecasts 1.9 million barrels.

Edison asserts that an adequate level of oil inventory is required to ensure reliable electric service to its customers. Edison states that its oil inventory recommendation of 6.3 million barrels provides a reliability of 96 percent while DRA's recommended oil inventory level of 4.4 million barrels would provide a reliability of less than 45 percent. In Edison's opinion, this level of reliability creates an unacceptable risk to Edison's customers. Additionally, Edison notes that it has never carried an average oil inventory at the level recommended by DRA.

Edison states that its forecast of 2.0 million barrels for station inventory is the minimum level of oil needed on

site at Edison's generating stations to guarantee uninterrupted operation of Edison's oil/gas-fired facilities when gas service is curtailed. Edison's forecasted POB comprises 86% of its system inventory forecast of 3.3 million barrels.

DRA states that its recommended 4.4 million barrel fuel oil inventory is the same inventory level that was approved less than a year ago in D.87-11-013, at which time Edison had requested a 6.0 million barrel inventory. It is DRA's opinion that Edison has not demonstrated the need for an increase over that authorized level even though it now requests a 6.3 million fuel inventory.

Specifically, DRA believes that neither reason offered by Edison (i.e., expected level of gas curtailment and alleged changes in Edison's oil resupply strategy) supports the increase in fuel oil inventory requested by Edison. DRA states that its gas availability analysis indicates that adequate gas supplies will be available and the 1.9 million barrels authorized for last year will be sufficient. DRA adds that Edison still has contractual rights under the Chevron Option Agreement to purchase up to 2 million barrels per month, which has the effect of lowering Edison's LSFO inventory.

DRA also asserts that its direct testimony and cross-examination of Edison's witness in this proceeding demonstrated that Edison was using the same resupply strategy as it had in the last ECAC period, and that any intended changes had not as yet actually taken place. DRA notes that Edison also testified that the intended changes would result in less rapid delivery of oil. DRA asserts that slower delivery will increase, not decrease, reliability.

In response to Edison's assertion that the 4.4 million barrel level recommended by DRA would yield only a 45% reliability level, DRA states that a comparison with a similar analysis used by Edison in its 1987 ECAC is instructive.

Specifically, DRA states that from the 1987 ECAC to the 1988 ECAC, Edison's predicted reliability for 6.3 million barrels dropped less than 2% (from near 98% to near 96%). By contrast, DRA notes that, according to Edison's testimony, the 4.4 million barrel level recommended by DRA is predicted to drop a precipitous 24% in reliability from the 1987 ECAC to the 1988 ECAC. DRA states that Edison failed to substantiate the basis for this dramatic change in projected reliability.

As stated in previous sections, we have found DRA to have made a reasonable forecast of gas curtailment in the current ECAC forecast period. We do not find sufficient evidence in this record supporting the changes which Edison asserts require fuel oil inventory level over the level adopted in its 1987 ECAC. DRA has noted the many portions of Edison's testimony where Edison has failed to adequately demonstrate this increased need. We therefore find reasonable and adopt DRA's forecast of a 4.4 billion barrel fuel oil inventory level.

(2) Fuel Oil Inventory Carrying Costs

The difference between DRA's and Edison's fuel oil inventory carrying costs is attributable to differences in their forecasts of the appropriate fuel oil inventory level for the forecast period. Both parties forecast carrying costs using short-term interest rate forecasts plus 0.25 percent for administrative costs. Having adopted DRA's fuel oil inventory level for the 1988 forecast period, we will therefore similarly adopt DRA's fuel oil inventory carrying costs.

(3) Fuel Oil Inventory Ratemaking Treatment

DRA and Edison agree on the ratemaking treatment for fuel oil carrying costs, variations from adopted levels, and gains or losses. Specifically, the parties agree that treatment of these items should remain the same as adopted in D.87-11-013. That order provided as follows:

> "Consequently we will treat Edison's oil inventory levels and cycling amounts as

> follows. Edison will be authorized ECAC-AER rates at the 4.4 million barrel level. Edison will establish a memorandum account that will debit 90% of carrying costs, at the short-term interest rate, on the difference between recorded inventory levels and the authorized 4.4 million barrel level. It will also debit 90% of any losses (or credit 90% of any gains) incurred in cycling fuel oil. The account balance will be considered in Edison's next ECAC case with Edison bearing the burden of proof that the actual inventories and purchases and sales were reasonable, for possible recovery of the memorandum account balance through ECAC rates." (D.87-11-013, at p. 30.)

Consistent with the preceding approach, DRA and Edison recommend that any fuel oil sale loss be recorded in the memorandum account with the opportunity for future recovery.

Edison notes, however, that it had first requested that fuel oil inventory carrying costs be made subject to the ECABF/AER percentage allocation so that such expenses would be given ratemaking treatment consistent with other fuel and purchased power expenses. However, due to time constraints, it ultimately agreed with DRA to follow the ratemaking treatment adopted in D.87-11-013. Edison asks, however, that to the extent that the Commission establishes different accounting procedures for fixed oil inventory carrying costs in PG&E's 1988 ECAC proceeding (A.88-04-005, A.88-04-035), the same procedures be adopted for Edison.

Consistent with the DRA's and Edison's agreement, we will continue in effect the ratemaking treatment adopted in D.87-11-013 for Edison's fuel oil inventory carrying costs. The fact that different procedures might be adopted for PG&E, however, does not necessarily warrant or require their mandatory application to Edison. In Edison's next ECAC, hopefully sufficient time will exist for Edison to demonstrate the need for an accounting

approach different from that adopted in this proceeding, if one is warranted.

b. Coal and Nuclear Inventory Carrying Costs and Ratemaking Treatment

DRA and Edison agree that the forecast coal inventory should be approximately 392,000 tons at Mohave and 226,000 tons at Four Corners. DRA and Edison agree that coal inventory carrying costs should be calculated based upon the estimated short-term debt interest rate plus financing issuance costs of 0.25 percent. DRA recommends use of the latest Data Resources Inc. three-month commercial paper rate.

DRA and Edison also agree that nuclear inventory carrying costs should be approximately $25.3 million. Edison states that DRA did not object to Edison's proposal that nuclear fuel inventory should be financed with a blend of short-term and intermediate-term debt.

With respect to the ratemaking treatment of coal and nuclear inventory, the Commission in D.87-12-066 transferred the rate recovery of coal and nuclear inventory carrying costs from base rates to ECAC rates effective January 1, 1988. The Commission ordered that coal inventory carrying costs should be calculated using short-term debt interest rates and be included 100 percent in the ECAC balancing account. For nuclear inventory carrying costs, the Commission ordered that these costs be calculated using ECAC interest rates and included 100 percent in the ECAC balancing account.

Initially, Edison proposed further ECAC tariff modifications so that coal and nuclear inventory carrying costs would be subject to the ECABF/AER percentage allocation commencing June 1, 1988. Later Edison agreed to withdraw this request if the presently authorized 100% ECAC balancing account treatment of coal carrying costs remained in effect. Because DRA recommended "lump sum" ratemaking, rather than 100 percent balancing account,

treatment, however, Edison returned to its original request that the recorded and adopted carrying costs associated with nuclear fuel inventory and coal inventory be subject to the ECABF/AER percentage allocation.

In the alternative, Edison proposed that, for consistency with the present fuel oil inventory ratemaking treatment adopted in D.87-11-013, a memorandum account could be authorized to record variations in carrying costs due to inventory level changes and gains or losses on sales. Edison believes, however, that Commission authorization is required to create such an account.

DRA believes that Edison's adopted carrying costs should be fully recoverable through the ECAC balancing account. However, in DRA's view, the authorized carrying costs should be considered as the "lump sum" total of Edison's authorized carrying costs. DRA proposes a "true-up" of the interest rate at the end of the forecast period. According to DRA, this "true-up" would permit Edison to recover its authorized carrying costs based on the actual interest rate over the forecast period. DRA states that if Edison's actual carrying costs differ from the authorized level, then Edison may apply for recovery of the shortfall or return of the excess. DRA states, however, that it would not oppose authorization of memorandum accounts for coal and nuclear fuel inventory carrying costs.

Edison believes that DRA's "lump sum" proposal is inconsistent with the ratemaking treatment adopted for Edison's fuel oil carrying costs in D.87-11-013 and for San Diego Gas and Electric Company (SDG&E) in D.87-12-049 in its 1987 ECAC proceeding. Edison notes that the Commission rejected DRA's "lump sum" approach in D.87-12-049 because it would single out fuel oil inventory for different ratemaking treatment. Edison states that the Commission in that decision also concluded that such isolated treatment could result in perverse incentives for utility

management to focus on inventory costs more than other energy costs.

As Edison correctly points out, the Commission in D.87-12-069 declined to adopt DRA's "lump sum" approach for fuel oil inventory carrying costs. We took this step not because of some inherent flaw in such an approach, but rather because we could find no explanation why this particular energy expense should be segregated from other expenses and given different treatment. We expressed concern, as noted by Edison, that such an approach could "create perverse incentives for utility management." (D.87-12-069, at p. 11.)

Given our continuation of a memorandum account for fuel oil inventory carrying costs, we find that the only reasonable approach is to direct Edison to create similar accounts for its nuclear fuel carrying cost and coal inventory carrying costs. Edison will therefore be entitled to recover 100% of its adopted nuclear fuel and coal inventory carrying costs in ECAC and will be authorized to record in memorandum accounts variations in these carrying costs due to differences in inventory levels from the authorized levels and gains or losses on sales.

3. Franchise Fees and Uncollectible Accounts Expense and Resale Accounts Allocation

A $1.0 million difference between DRA and Edison for franchise fees and uncollectible accounts expense and resale accounts allocation is due solely to differences in forecast fuel, purchased power, and energy-related expense. Based on our adoption of DRA's forecasts and its use of the ELFIN model to develop Edison's revenue requirement, we find reasonable DRA's recommended franchise fees and uncollectible accounts expense and resale accounts allocation.

E. QF Payment Components

This ECAC marks the beginning of the Commission's regular annual updating of variable QF payments in the utilities' ECAC

proceedings. In this section, we will focus on the calculation of the utility's variable QF capacity and energy payments and, in particular, the ERI and IER used in determining those payments.

With the aid of the workshops held in advance of hearings in the forecast phase, the parties were able to reach agreement on many of the resource assumptions and modeling issues impacting the calculation of Edison's IER. This procedure has greatly enhanced consideration of these complex issues in this hearing process and should be continued.

Nevertheless, several issues related to QF energy payments remained in dispute. With respect to resource assumptions used to determine both Edison's IER and revenue requirements, those issues have been addressed in the previous section. In this section, we will therefore focus on the remaining issues in dispute impacting the IER calculation and QF energy payments. These issues include the selection of a commit target variable, the substitution of cold-standby units in the "QFs-Out" run, and consideration of forced outages in determining system capacity.

In our discussion of QF energy payments, we will also consider the more generalized debate among the parties regarding the efficacy of each party's approach to ELFIN, the validity of proposed reasonableness tests of ELFIN produced results, and the introduction by the CCC/CSC of new IER runs in its opening brief. In addition, we will also examine Edison's avoided cost of gas and the fixed gas component reflected in QF energy payments.

Testimony on these issues was presented by Edison, DRA, and the CCC/CSC. During the course of hearings, these parties reached agreement on the value of Edison's ERI. No agreement, however, was reached with respect to the IER.

1. <u>ERI Stipulation</u>

During hearings in this proceeding, Edison, DRA, and the CCC/CSC stipulated that 0.43 was a reasonable value for Edison's ERI. We understand that these parties had a full opportunity to

review the bases for each of their recommendations. We have in turn reviewed the stipulation and conclude that 0.43 is a reasonable value for Edison's ERI and should be adopted. Late-filed Exhibit 77, DRA's updated revenue requirements showing, incorporates this stipulated value.

2. IER and QF Energy Payment Issues

The Commission has determined that IERs are to be calculated using the "QFs In /QFs Out" methodology. (D.88-03-079, at pp. 29-32.) The "QFs In/QFs Out" simulation involves two model runs. The first or "QFs In" run "represents system dispatch with all variably priced QFs anticipated to be on-line during the forecast period." (Id., at p. 23.) The second or "QFs Out" run "represents the projected dispatch of the system with all variably priced QFs removed." (Id.) The IER is based upon the difference in costs between the two runs, divided by the quantity of variable priced QFs.

While the Commission in D.87-12-066 required that ELFIN be used by each party for a "base case" IER calculation, the parties were also entitled to present IER recommendations based on production cost models of their choice. In this proceeding, however, no party chose to present results from a production cost model other than ELFIN.

a. Parties' Positions on Overall IER Development and Recommendations

With gas as the marginal fuel, the parties' annual average IER recommendations are as follows:

Edison	9,650 Btu/kWh
DRA	9,533 Btu/kWh
CCC/CSC	10,116 Btu/kWh

These IER recommendations reflect each party's resource assumptions, rather than those adopted by the Commission in this decision. Additionally, DRA's presently recommended IER of 9533

Btu/kWh represents a reduction from DRA's previous IER of 9661 Btu/kWh.

In its opening brief, CCC/CSC criticized DRA's and Edison's approach and expertise in using ELFIN. Specifically, CCC/CSC asserts that Edison's and DRA's analyses are based upon flawed or inconsistently applied input assumptions and modeling conventions, a failure to reflect the operating realities of the Edison system, and a continued historical pattern of systematically overestimating forecast average system heat rates and underestimating forecast IERs.

The source of these problems, in CCC/CSC's view, lies primarily in DRA and Edison failing to conduct reasonableness reviews of their ELFIN results and to impose "audit controls" to ensure consistency in ELFIN's outputs with actual system operation. In particular, CCC/CSC that argues that ELFIN results should be reviewed (1) to ensure that forecast IERs reflect historical IERs and heat rates, (2) to ensure that concerns with revenue requirement do not dictate IER results, (3) to constrain the ELFIN run in providing estimates of PSW economy power, and (4) to ensure that IER levels vary with a decrease in resources between the "QFs-In" and "QFs-Out" runs. We have previously discussed the constraint of PSW economy energy results in our section on Edison's adopted resource mix.

In its opening brief, CCC/CSC sought to show the impact on the parties' IER results of its "audit controls" and the assumptions which CCC/CSC identified as the "benchmark standards" (i.e., the commit target value, the treatment of substitution units, PSW modeling, and gas dispatch prices). To this end, CCC/CSC presented the results of sensitivity runs on ELFIN using the varying positions of the parties. Using the values it assigned to the "benchmark standards", CCC/CSC recited IER values for DRA and Edison significantly increased over those recommended by the parties.

CCC/CSC states that it is offering these sensitivity runs as "additional arguments" and "extensions of the theories presented in the evidentiary record." (CCC/CSC Opening Brief, at p. 7.) CCC/CSC further states that "these integrated assessments [are] offered to show and support the 'robustness' of CCC/CSC's result", but not "as alternative recommendations to the evidentiary record." (CCC/CSC Opening Brief at pp. 7 & 28.)

In its opening brief, Edison challenges the CCC/CSC's choice of using the 1987 recorded IER data to judge the reasonableness of the IER forecasts of Edison, DRA, and CCC/CSC. Such a comparison, according to Edison, is misleading in that it implicitly assumes that conditions during 1987 will be the same as the 1988 ECAC forecast period. Edison states that, in fact, conditions during 1987 were very unusual and are not expected to be repeated during the forecast period. In making its comparison, Edison charges that CCC/CSC has chosen only to look at the highest recorded value for IERs in the last three years.

Edison also believes that, in judging the reasonableness of ELFIN results, it is erroneous to compare average heat rates to incremental heat rates. Similarly, Edison asserts that it is erroneous to assume that the IER level must change in response to a decrease in available resources.

Edison also objects to CCC/CSC's offering new ELFIN runs in its brief to "prove" the efficacy of CCC/CSC's approach to ELFIN modeling or the assumptions upon which it relied. Edison states that CCC/CSC's proposals go well beyond sensitivity analyses and are a blatant example of CCC/CSC introducing improper, invalidated computer runs in its briefs. In Edison's view, CCC/CSC's analyses are facts, not legal theories, requiring cross-examination. In this regard, Edison observes that it has been unable to duplicate CCC/CSC's results and therefore must assume that CCC/CSC's IERs are supported by assumptions which are not part of the record.

DRA similarly responded not only to CCC/CSC's new sensitivity runs, but also to its claims that DRA's IER was "unaudited" and "a classic counter-intuitive model result." (CCC/CSC Brief, p. 9.) DRA states that CCC/CSC's "attack" on DRA's model results is without any basis in the record. According to DRA, CCC/CSC has not explain what is meant by "unaudited" ELFIN results and has failed to demonstrate any errors in DRA's methodology.

DRA joins Edison in objecting to CCC/CSC's claim that forecasted IERs should reflect recorded IERs or that the IER should necessarily have increased "because of the need to start up additional oil and gas fired units to meet the increased need for capacity." (CCC/CSC Brief, p. 9.) According to DRA, of the total reduction in energy between the "QF In" and QF Out" runs, a significant part was due to decreased PNW economy energy. DRA states that there would not necessarily be an increased need for capacity when economy energy is reduced since economy energy does not count toward spinning reserve.

Like Edison, DRA challenges CCC/CSC's attempt in its opening brief to offer new, totally unsubstantiated "sensitivity" analyses of both Edison's and DRA's latest IER figures. DRA notes the impropriety and fundamental lack of fairness of CCC/CSC's tactics. DRA and Edison both note that no work papers supporting these runs were offered to either party nor was there any notice of CCC/CSC's intent to submit new "evidence" in its brief. DRA states that it was therefore denied an opportunity to cross-examine CCC/CSC on this new evidence or to make timely data requests or analyses.

We are constrained in this proceeding by the limited amount of time available to hear and resolve Edison's 1988 ECAC forecast phase. This circumstance has produced procedural results which we hope may be avoided in Edison's next ECAC. It obviously would have been preferable to split the forecast phase into two

parts--one for the adoption of resource mix and IER assumptions and the second for reviewing and adopting results based on parties' recommendations using those assumptions. In this way, the parties would have had an opportunity during the second hearings to discuss any "reasonableness tests" or "control audits" which should be applied to their ELFIN results based on the adopted assumptions. While such an approach was not feasible in this proceeding, we believe, as our following discussion reflects, that our adopted procedures will have provided all parties a full and fair opportunity to litigate the issues in this proceeding.

Unlike revenue requirement and resource mix assumptions previously discussed, we are unable to uniformly adopt any single party's position for each of the remaining disputed issues related to QF payments. It will therefore be necessary for the parties to "re-run" their ELFIN models using the adopted values and provide their updated IER recommendations during the comment phase. Each of these runs will be considered a late-filed exhibit.

Although there will not be the opportunity to examine these revised recommendations in a hearing setting, we believe that such "testing" of these results is not necessary. Specifically, through several days of workshops and many days of hearings, the parties have become well-acquainted with the modeling approaches used by the parties. CCC/CSC's brief appears to suggest that post-processing "reasonableness tests" should alter DRA's and Edison's IERs. However, a closer examination of CCC/CSC's "new evidence" reflects that the changes are dependent on the values assigned to the four "benchmark standards." These standards are no more than four of the values at issue in this proceeding. Once these issues are resolved in this decision, CCC/CSC's position seems to suggest that only slight differences in the final IERs should result.

The latitude which we lose in this proceeding due to its short time-frame is the ability to adopt methodologies, as suggested by CCC/CSC, instead of absolute values and to permit

individual "reasonableness" tests of end-results. As an example, we have in fact chosen commit target values in this proceeding instead of a methodology as urged by CCC/CSC. This conclusion, however, does not mean that in future ECACs a methodology or an "iterative" approach might be selected by the Commission followed by hearings which would permit the examination of each party's application of that methodology.

Until that time, however, we believe that the record in this proceeding supports our adopted values and our consideration during the comment phase of IER recommendations based on those values. If there were concerns regarding the way in which a particular party used a model in this proceeding, the hearings which have already been held were the appropriate forum for raising those concerns. In this regard, we find insufficient evidence, despite CCC/CSC's innuendos to the contrary, that Edison, DRA, or even CCC/CSC used the ELFIN model in an inappropriate way.

We also find that DRA and Edison have adequately responded and rebutted CCC/CSC's challenge to their modeling judgment. The only concrete suggestion offered by CCC/CSC as a means of judging the reasonableness of the parties' overall IER recommendations is how closely they mirror the past year's recorded IER. We find irony in CCC/CSC's reliance on the past in this instance, when it so strenuously objected to Edison's and DRA's algorithm used to develop economy energy quantities for its reflection of the past in the present.

Obviously, sole reliance on the past is not appropriate in any forecasting effort. While we would question an IER in one year which was significantly different from the previous year, we would logically look first to the assumptions made leading to that result. If the ultimate results produced by the parties using the adopted assumptions differ considerably from each other or from the previous ECAC period, the Commission can then determine the necessity of taking further action, including additional hearings,

before adopting an IER. It is our hope that such action is not required since it will mean an additional delay in achieving updated QF prices for at least part of the current forecast period.

As a final point, we concur with Edison and DRA regarding the impropriety of CCC/CSC introducing new sensitivity analyses in its opening brief. Whether CCC/CSC wishes us to adopt the actual results presented in its brief or not is irrelevant to the issue of whether the material is evidence. Specifically, we find that any factual matter or expert opinion upon which a party intends the Commission to rely as support for or a challenge to a particular position is evidentiary in nature.

We wish to distinguish CCC/CSC's actions from our decision to permit the parties to include final IER recommendations in their comments. We believe that, in the latter case, we have attached sufficient procedural safeguards to this process to permit our consideration of these recommendations. In particular, we have established that (1) each party will have the same opportunity to present their recommendations at the same time and under the same circumstances, (2) each of these submissions will be accorded the same status (late-filed exhibit), (3) the same assumptions will be used, (4) supporting work papers will be served on each party performing a model run, and (5) each party will have the opportunity to address the revised recommendations in their comment responses.

b. Remaining IER and QF Energy Payment Issues

(1) Addition of Standby Units in the "QFs Out" Run

At issue in this proceeding is whether cold standby units should be included in the "QFs-Out" run in calculating the IER, and, if so, what units are appropriately reflected in that run. Both Edison and DRA returned two cold standby units (Alamitos 3 and Huntington 3) to service for the forecast period in the "QFs-Out" run, while CCC/CSC objected to any standby units being added.

CCC/CSC asserts that even if standby units could be added to the "QFs Out" run, Etiwanda 12 and San Bernardino 12 are the appropriate units to add. Further, CCC/CSC argues that their addition should be limited to the two-month period in which a capacity shortfall is projected.

Edison asserts that its approach in its "QFs-Out" run of adding the two standby units and valuing as-available capacity at less than 100 percent is justified. Edison states that logic dictates that as-available capacity is not worth the full cost of a combustion turbine (CT) as long as there are units on cold-standby reserve that can be brought back to service for less than the cost of constructing CTs.

In support of its returning cold-standby units to service, Edison states that removing all variably priced QFs from the resource base without adding some resources to the "QFs Out" resource base would result in inadequate spinning reserve margins. Edison therefore concludes that, if these QFs were removed from the Edison system, its response would not be to run the existing system harder, but rather to return cold standby units to service.

According to Edison, in this scenario it chose to return Alamitos 3 and Huntington Beach 3 to service since both facilities can be returned to service quickly and at a fraction of the cost of constructing new generating facilities. In Edison's view, the addition of these two units to the "QFs-Out" run, results in an adequate spinning reserve margin for the "QFs-Out" run and correctly accounts for commitment costs in the IER calculation. In the long-term, Edison states that the Alamitos 3 and Huntington 3 units are more appropriate to return to service than the units suggested by CCC/CSC because they are more efficient. Edison also believes that it is reasonable to include these units in the "QFs Out" run each month of the forecast period.

As stated above, DRA agrees with Edison's position on the addition of Alamitos 3 and Huntington 3 as replacement units

in the "QFs Out" run. DRA states that forcing ELFIN to assume that no units were available in months of capacity shortfall would not reflect the way the system would actually operate under those conditions, particularly when those units can be brought on-line within five days.

Both DRA and Edison assert that D.88-03-079 permits the inclusion of cold-standby units in the "QFs-Out" run. According to these parties, that order prohibits "substitute," and not "existing," resources from being added to this run. In Edison's and DRA's opinion, the prohibition in D.88-03-079 therefore applies to resources which have not yet been built as opposed to those already on the utility system, but placed on standby status until needed.

In contrast to this position, CCC/CSC specifically equates the "substitution units" excluded by D.88-03-079 from the "QFs-Out" run with the standby units included by DRA and Edison in their "QFs Out" run. CCC/CSC therefore asks the Commission to reject the inclusion of these units by DRA and Edison.

CCC/CSC states, however, that, if Edison and DRA are correct in their interpretation of D.88-03-079, changes must be made to their approach. Specifically, CCC/CSC recommends the following: (1) if there is a shortage of capacity as the infusion of substitution units suggests, then as-available capacity must be valued at 100%, (2) substitution units should only be brought back for the two months (August and September) during which Edison's testimony reflects a model projection of a possible shortage of capacity, and (3) the choice of units should be Etiwanda 12 and San Bernardino 12.

With respect to this last point, CCC/CSC notes that, while Edison chose to bring back Alamitos 3 and Huntington 3, in actual practice Edison has relied on Etiwanda 12 and San Bernardino 12 as standby units. CCC/CSC states that these units are far less efficient than the two chosen for the model runs.

In D.88-03-079, we concluded that the "QFs In/QFs Out" methodology should be used by all utilities for calculating variable energy payments for QFs. In reviewing that methodology, the Commission rejected the proposal to include "substitute" units in the "QFs Out" run. The Commission in defining this issue was referring to the circumstance in which "a utility will incur energy-related capital costs to add a new resource (in order to lower its operating costs) rather than run its existing system harder." (D.88-03-079, at pp. 25-26.) Specifically, the Commission rejected the placing of "a cap on variable energy prices whenever a utility has so many short-run QFs on its system that it would substitute a new resource to lower its operating costs if all these QFs were removed from its resource plan." (Id., at p. 26; emphasis added.)

The meaning which we intended to give the phrase "substitute units" in D.88-03-079 has therefore been correctly interpreted by DRA. A substitute unit is a "new" resource added in response to the absence of short-run QFs and not an "existing" unit returned from cold standby to fill an intermittent loss of capacity. We anticipate, and expect, those performing a "QFs Out" run to return cold standby units to service in response to such a shortage in capacity.

While we believe that it is appropriate to include standby units in the "QFs Out" run to mirror reality, we similarly believe that the type of unit returned to service and the length of time for which it is returned should also reflect actual system operations. We find that CCC/CSC has demonstrated that the units which should be returned under these circumstances should not be Alamitos 3 and Huntington 3 and that the need for standby units exists in only two, and not twelve, months of the forecast period. In this regard, we are concerned that Edison would be keeping any "efficient" unit on standby status. Further, while Edison argued

that the efficiency of the unit was important because of the "long-term" resource need, we question the necessity of reflecting a long-term resource need in variable QF energy payments.

We therefore adopt CCC/CSC's recommended changes to Edison's and DRA's approach to including cold standby units in the "QFs Out" run. These changes would include returning to service Etiwanda 12 and San Bernardino 12 in the two-month period in which a capacity shortage was forecast. We also concur with CCC/CSC that, during this period of capacity shortfall, as-available capacity should be valued at 100%.

(2) Accounting for Forced Outages

Both DRA and Edison reduced or "derated" system capacity to account for forced outages as well as maintenance. In challenging DRA's and Edison's approach, CCC/CSC states that de-rating capacity for both maintenance and forced outages artificially and inappropriately lowers the reasonably expected availability of Edison capacity.

In contrast, CCC/CSC states that its approach, to derate capacity for maintenance outages only, reflects Edison's actual system operations. CCC/CSC believes that its method also avoids double counting for forced outages--once in the available capacity and again in the spinning reserve commitment. In using its approach, CCC/CSC further states that there will be ample spinning reserve to cover Edison's spinning reserve requirements in the CCC/CSC base case.

DRA states that ELFIN, in modeling the future, is unlike a real system operator who will actually know whether a resource is subject to a forced outage at the time a commitment decision must be made. DRA asserts that the duration of capacity to reflect forced outage rates provides ELFIN with the next best (and only) information which can be provided a model-it describes the probability of a forced outage at any given time. In DRA's view, failure to provide ELFIN with information on the forced

outage rates of the resources it commits will systematically overstate the probable capacity available to the system at a given time based on a given mix of committed resources.

Edison similarly finds CCC/CSC's approach flawed for its failure to recognize forced outages and its assumption that all committed units are available at 100 percent capacity for 100 percent of the forecast period. According to Edison, the result is that costs that would be incurred to bring additional units on-line when the committed units sustain a forced outage are ignored in the CCC/CSC modeling and in turn produce unrealistic results.

We find that CCC/CSC has made a valid point regarding the need to reflect the realities of Edison's system operations as closely as possible in forecasting the future through ELFIN. This reality, however, includes the "probability" of forced outages. We therefore find that it is reasonable for ELFIN to reflect this probability and its impact on the availability of Edison's system capacity.

In this proceeding, the only approach before us which achieves this end is that proposed by DRA and Edison. We therefore adopt DRA's and Edison's recommendation to de-rate capacity for forced outages and maintenance. CCC/CSC is, of course, welcome in Edison's next ECAC to develop and propose a different approach which it believes more precisely reflects this impact in an ELFIN run.

(3) Commit Target Variable Values

In determining Edison's IER, it is necessary for the production cost model that is used to accurately assess the costs of serving load. To this end, it must achieve about the same level of spinning reserves as maintained by system operators.

All parties in this proceeding relied on the ELFIN production cost computer model. In using ELFIN, the modeler cannot directly input a spinning reserve level, but instead relies on a "commit" variable to influence spinning reserves. This "commit

target variable" is intended to tell ELFIN when to commit additional resources and permits the ELFIN modeler to specify a reserve margin. A commit value which is too high or too low results in either an over-commitment or under-commitment of units, respectively, to meet system load and spinning reserve requirements.

The monthly ELFIN commit target values relied upon by the parties are illustrated in the following table reproduced from Appendix A of DRA's concurrent opening brief. The table reflects DRA's changed commit target values resulting from the changed assumptions incorporated into the post-hearing ELFIN runs included in DRA's late-filed Exhibit 77.

Comparison of ELFIN Commit Target Values

	CCC/CSC (1)	DRA (2)	Edison (1)
1. June 1988	1.12	1.14	1.16
2. July	1.11	1.13	1.15
3. August	1.11	1.13	1.16
4. September	1.11	1.18	1.21
5. October	1.12	1.18	1.22
6. November	1.13	1.23	1.26
7. December	1.12	1.22	1.24
8. January 1989	1.22	1.24	1.26
9. February	1.24	1.28	1.29
10. March	1.24	1.26	1.29
11. April	1.22	1.25	1.27
12. May	1.19	1.21	1.23

(1) From Exhibit 64
(2) From DRA's late-filed exhibit (mailed June 17, 1988), Table 6-3L

Edison states that in determining its commit values it took into consideration the following two flaws which it found in the ELFIN commit logic: (1) the failure of the ELFIN commit logic to distinguish between firm resources and economy resources, and (2) the counting of all quick-start resources (combustion turbines) as contributing toward the commit target variable. Due to these deficiencies, Edison states that the ELFIN modeler must set the commit target higher than the desired spinning reserve target because some of the resources that ELFIN counts as contributing toward meeting the commit target do not in fact contribute toward spinning reserve.

Given these circumstances, Edison states that it developed its commit values by summing for each month the peak load, the spinning reserve requirement (7 percent of peak load or the largest single contingency, whichever is greater), the capacity of economy energy, and the capacity of combustion turbines. The resulting monthly sums were then divided by the peak load for each month to arrive at the monthly commit values. Edison states that this approach yields values which result in the spinning reserve target being achieved with those resources that properly contribute to spinning reserve.

Edison states that DRA and CCC/CSC followed a similar approach, but neither included the capacity associated with combustion turbines in setting their commit values. Additionally, Edison notes that DRA included an additional component omitted by both Edison and CCC/CSC. This component was the addition of 40 percent of the capacity associated with smaller QFs. Edison states that the result of both approaches are commit values lower than Edison, with CCC/CSC's being the lowest.

Edison asks the Commission to reject the CCC/CSC approach. In Edison's opinion, the absence of combustion turbines and non-spinning QF capacity in CCC/CSC's determination of its commit variable results in an undercommitment of spinning reserves.

Edison further states no work papers were produced by CCC/CSC reflecting a separate spinning reserve analysis which CCC/CSC had asserted supported the reasonableness of its results.

DRA states that its commit target is based on a ratio of two capacities. According to DRA, the numerator is the sum of peak capacity, seven percent of the peak capacity or the largest single contingency for spinning reserve, the total capacity of economy energy available during the peak hours, and forty percent of the forecast capacities of QFs under 40 megawatts. The denominator is the system peak capacity. DRA believes that its methodology for determining the commit value is straightforward and reasonable and should be adopted.

In developing a commit target value, it is CCC/CSC's position that the most important aspect is whether the value used creates model outputs which reflect the reality of the operating system. CCC/CSC therefore asks the Commission to endorse a methodology for deriving the commit value as opposed to the adoption of a specific commit value figure. CCC/CSC also requests that the Commission require verification that the model outputs commit system units in a manner which meets, but does not exceed, system load and spinning reserve requirements. In the absence of a commit value audit, CCC/CSC asserts that the Edison and DRA ELFIN models dramatically over-commit units resulting in high system heat rates and depressed IERs.

With respect to methodology, CCC/CSC states that its iterative methodology is different than and superior to the formalistic calculation used by DRA and Edison. CCC/CSC states that its methodology first requires determination of an initial value. This value is equal to the weekly peak load divided into the sum of the weekly peak load plus spinning reserve, the ELFIN capacity representation for PNW and PSW economy energy purchases, and 45% of the nonfirm purchases associated with resale load. The CCC/CSC then examines the initial commit number to determine if a

sufficient amount of capacity is committed to meet system peak load plus spinning reserve requirements.

Given the time constraints presented in this proceeding, we are not in a position to adopt a methodology for determining and adjusting the commit target variable like that proposed by CCC/CSC. As explained previously, the procedure which must be followed in this case, with ELFIN runs being performed during the comment period, does not present a sufficient opportunity for examination of each of the party's application of the methodology upon which two of the parties did not originally rely.

We find, however, that each of the parties' approaches to achieving a commit target value is similar and designed to meet the same goals--the determination of a reasonable system load projection. The only significant differences appear to be in the treatment of certain sources of capacity.

We therefore find that the record is sufficient to adopt a specific commit target value in this proceeding. In our review of the parties' recommendations, we find that DRA's method includes those resource capacities which most appropriately should be considered in this calculation. Given this circumstance, and our adoption of DRA's resource mix assumptions, DRA's commit target values for the forecast period are reasonable and should be adopted.

(4) Post-Processing Adjustments

With respect to post-processing adjustments to ELFIN's output, DRA accounted for "general optimization" and start-up costs by escalating the heat rates flowing from ELFIN by 1.4 percent. CCC/CSC proposed a model adjustment of 30 Btu/kWh to account for start-up costs.

Edison states that while it does not disagree with a post-processing adjustment to reflect start-up costs, Edison believes that it is superfluous to add 30 Btu/kWh to account for

these costs. In Edison's opinion, ELFIN already overstates a reasonable level of start-up and no load in its no load estimate.

In D.87-12-066, the Commission concluded that any adjustment of ELFIN to account for start-up costs should not result in any "double-counting" of those costs. (D.87-12-066, at p. 207.) To avoid this result, which Edison apparently asserts could flow from CCC/CSC's approach, we will adopt DRA's recommendation to escalate ELFIN heat rates by 1.4 percent.

3. Gas Costs Reflected in QF Energy Payments

In our earlier section on revenue requirements, we adopted a gas price forecast which dictates the dispatch price of gas impacting the calculation of the IER. In addition, however, we must also consider the determination of the fixed gas cost and avoided cost of gas, both of which are reflected in QF energy prices.

In this proceeding, Edison and DRA used different methods for calculating the fixed gas cost included in QF energy prices. DRA calculated the average fixed gas costs by dividing the allocated fixed costs from the SoCal CAM proceeding by the gas volumes forecast in this ECAC proceeding. Instead of using the ECAC gas volumes as the denominator in calculating fixed gas costs, Edison used the gas sales forecast from the SoCal CAM proceeding.

It is Edison's position that to determine the average fixed gas costs, it is more consistent to divide the allocated fixed gas costs developed in the SoCal CAM proceeding by the gas sales volume which were developed in that same proceeding. In Edison's opinion, DRA's proposed methodology could cause QF prices to vary erratically if the gas sales forecast changes between the SoCal CAM proceeding and the ECAC proceeding.

Edison also believes that DRA's approach is premature and philosophically unsound. Edison states that it is unreasonable and unfair to reward QFs with higher payments when it is the unexpected increase in QF production, resulting in a decline in gas purchases

and an increase in average fixed gas cost, which causes the payments to be higher. Edison states that DRA has not yet provided Edison with a quantification of the amount of additional payments resulting from the higher prices paid to QFs.

DRA states that its approach is based on the methodology adopted by the Commission in D.86-10-045. In that decision, we ordered PG&E to use "the most recent forecast of gas burn adopted," which would be the more recent of the ECAC or the CAM forecasts. (D.86-10-045, at p. 3.) While DRA recognizes that D.86-10-045 involved PG&E's and not Edison's fixed gas costs, DRA asserts that QF payment methodologies under the standard offer contracts are intended to be uniformly administered among the three utilities that have such contracts. Based on this consideration, DRA urges the Commission to order Edison to conform to the methodology in D.86-10-045.

CCC/CSC believes that DRA's reliance on D.86-10-045 is reasonable. DRA's recommendation, in CCC/CSC's view, has the effect of making a consistent application of the Commission policy to use "the latest forecast gas burn adopted" for QF gas pricing.

We concur with DRA and CCC/CSC that, for consistency, the same approach for determining fixed gas costs announced in D.86-10-045 should be applied to Edison, as well as PG&E. Although this decision involved PG&E, Edison was fully aware of DRA's proposed application of the adopted methodology to Edison in this proceeding. Under these circumstances, Edison has therefore had an adequate opportunity to address the methodology and its application to Edison. In this regard, we do not find Edison's arguments sufficiently persuasive to adopt different approaches for the two utilities.

With respect to the reflection of avoided gas costs in QF energy payments, we note that the parties agreed to follow the approach adopted in the generic standard offer proceeding (A.82-04-044, et al.). On July 8, 1988, in that proceeding, the

Commission issued D.88-07-024 addressing gas costs avoidable by QFs.

In D.88-07-024, the Commission concluded that the variable energy payments to QFs should be calculated as follows:

> "Except for the customer costs, all gas utility fixed costs allocated to the UEG [utility electric generation] customer are avoidable. Also, the UEG customer's gas commodity costs are 100% avoidable by QFs. For an electric utility that takes noncore procurement service, the energy payment to QFs is calculated using the LDC's noncore portfolio WACOG. For an electric utility that elects service from both the core and noncore portfolios, the energy payment to QFs is calculated using an average of the two WACOGs, considering the relative volumes purchased by the electric utility from each portfolio." (D.88-07-024, Conclusion of Law 3, at p. 24.)

We adopt this approach in this proceeding and will direct Edison to determine its QF energy payments consistent with D.88-07-024.

F. Revenue Allocation

In our discussion of revenue allocation in Edison's most recent general rate case, we examined the two primary methods of allocating revenue--the system average percentage change (SAPC) methodology and the equal percent of marginal cost (EPMC) methodology. In D.87-12-066 in that proceeding, we reiterated our support for marginal cost ratemaking as a means of achieving cost-based rates. To this end, we adopted an EPMC revenue allocation.

In adopting this methodology, however, we also recognized the need to mitigate negative impacts which might be caused by its use. We found that this consideration was of particular importance in the case of Edison for which an EPMC revenue allocation would result in a significant shift of revenue responsibility between Edison's customer groups. This impact was largely due to an historic allocation of Edison's revenues on bases other than EPMC which had caused Edison's rates to be quite far from EPMC. We

therefore found that the move to EPMC would result in significant rate increases to the domestic class coupled with substantial rate decreases to the large power class.

With these factors in mind, in D.87-12-066 we adopted a modified version of Edison's proposal to allocate revenue on the basis of a weighted average of 2/3 SAPC and 1/3 EPMC in the first year of its three-year rate cycle. The modification of this approach involved placing a cap of 5% on increases over present rate revenues. Any remaining revenue decreases were to be spread to the large power classes in proportion to the deviation of each class from full EPMC. We also concluded that our adoption of a 5% cap for residential customers would provide adequate relief from rate shock while still yielding significant rate reductions for large power customers. (D.87-12-066, at p. 262.)

For rate changes occurring between Edison's general rate cases, we indicated that we would "continue phasing-in to full EPMC, mitigating rate shock as required by using caps" and that we intended to achieve full EPMC revenue allocation for Edison "as soon as possible." (D.87-12-066, at p. 262.) We also stated the following:

> "For rate changes occurring between this rate case and Edison's 1989 ECAC, the rate schedule changes should consider both the system average percentage change methodology and the phased-in EPMC methodology. Edison should file proposals using both methods and indicating the utility's preferred approach. Similarly, the revenue allocation approach proposed in Edison's ECAC proceedings for the 1989 and 1990 periods should identify the methodology to be applied to Edison's intervening offset filings made after each of these proceedings if other than SAPC." (D.87-12-066 at p. 264.)

We concluded, however, that the consideration of revenue allocation issues in ECAC did not and should not include relitigation of the marginal cost structure and levels adopted in the general rate case. (Id.)

In D.88-04-026, modifying D.87-12-066, we reconfirmed our decision to require that Edison file both SAPC and phased-in EPMC proposals in its 1988 ECAC proceeding. Parties to this proceeding were also "permitted to comment on Edison's proposed revenue allocations and provide their own illustrations of an SAPC and a phased-in EPMC allocation." (D.88-04-026, at p. 8.) The testimony, however, was not to involve a re-examination of the revenue allocation policies which the Commission announced in D.87-12-066 nor to serve as a forum for the consideration of either marginal cost or rate design issues.

In our interim order in this proceeding (D.88-05-074), we adopted an SAPC revenue change of 3.7%. In doing so, however, we made clear that adoption of an SAPC revenue allocation in the interim order was "not intended to predetermine the issue of revenue allocation in this proceeding nor preclude the evidentiary showings permitted under D.87-12-066 and D.88-04-026." (D.88-05-074, at p. 24.) Rather, it had been our intent to select a revenue allocation which would minimize the possibility of any single customer class receiving an interim increase greater than its final rate change.

We also concluded that our adoption of an SAPC revenue allocation was not at odds with our stated goal of moving toward an EPMC revenue allocation for Edison. Specifically, we noted that at the time of issuance of D.87-12-066 the Commission had not considered nor anticipated the need for interim rate relief in Edison's 1988 ECAC proceeding.

Against this background, the parties presented the following revenue allocation proposals in this proceeding. These proposals also require consideration of the treatment of interruptible credits and Edison's off-peak energy charge. As our subsequent discussion makes clear, we must now also consider the impact of recent changes in baseline legislation and the current

status of the Commission's investigation into ECAC scheduling changes.

1. Parties Positions

a. Basic Revenue Allocation Proposals

In this proceeding, Edison and TURN support a 100% SAPC revenue allocation. Edison states that its proposed SAPC revenue allocation is primarily aimed at mitigating the impact of 1988 revenue increases on residential customers. In support of its position, Edison argues that, if a phased-in EPMC revenue allocation were adopted in this proceeding, additional movement toward EPMC would occur only eight months after the first phase-in of EPMC on January 1, 1988.

Due to the magnitude of the revenue requirement increase requested in this proceeding, Edison believes that it is more appropriate to follow an SAPC approach in this proceeding. Relying on its proposed revenue requirement, Edison states that this approach results in an 8.4% increase to residential customers. With respect to the phased-in EPMC revenue allocations proposed by other parties to this proceeding, Edison states that these proposals result in revenue changes for the domestic group 3.1% to 4.4% higher than proposed by Edison.

It is also Edison's position that D.87-12-066 limits any step toward EPMC in a single year to a 5% annual increase over the system average percentage change to any customer group. In Edison's opinion, such an approach requires consideration of both the increase to domestic rates resulting from D.87-12-066 (4.9%) as well as that adopted in this proceeding. Edison believes that it has complied with this annual cap by an overall increase to domestic rates in 1988 of approximately 17 to 18% as compared to the system increase for the same time period of 12 to 13% based on its recommended revenue requirement.

Edison rejects any allegations that its proposal results in movement away from EPMC. Edison states that, while its proposal

results in customer groups moving further away from EPMC on a dollar basis, its approach in fact maintains the existing rate relationships of Edison's customer groups.

TURN's support for Edison's SAPC revenue allocation is based on several grounds. First, like Edison, TURN believes that mitigation of the impact of further rate increases in 1988 for Edison's domestic customers is critical. TURN states that, given the movement toward EPMC in the general rate case and other rate changes which could be reflected in this order, residential customers could face an increase of as much as 10% greater than the system as a whole.

TURN believes that the Commission should proceed cautiously to avoid a high bill situation this summer as was experienced by SoCal's residential gas ratepayers during the cold snap of the past winter. Absent changes in baseline rates, TURN believes the same result could occur to Edison ratepayers in an unusually hot summer with heavy air conditioning usage. TURN also objects to movement toward EPMC today, which would impose "almost certain" rate shock, based on speculation of the "possibility" of rate shock in 1989 and 1990. (TURN Brief at p. 3.)

Additionally, TURN notes that the testimony in this proceeding reflected an increase in marginal energy cost revenues. TURN states that, if this circumstance reflects a change in marginal energy costs, the distance of each class from EPMC could also change. In TURN's opinion, this circumstance could result in Edison's EPMC target being closer than parties to this proceeding have assumed.

Except for Edison and TURN, all of the other parties to this proceeding uniformly endorsed some form of phased-in EPMC revenue allocation. These recommendations included the following:

1. DRA--DRA recommends a revenue allocation based on a weighted average of 1/3 EPMC, 2/3 SAPC.

2. CLECA--CLECA recommends the use of a 100% EPMC revenue allocation with a 5% cap on increases over the system average percentage change. Because TOU-8 subtransmission and street lighting would have received a rate reduction under its approach, CLECA also placed a floor of present rates on all classes.

3. IU--IU's approach is based on a smaller step toward EPMC in this proceeding with two larger steps in the next two ECACs. IU therefore proposes moving one-half of the way between the maintenance of existing subsidy relationships and reduction of those subsidies by one-third.

4. FEA--FEA proposes that a 20 percent reduction of the dollar deviation from EPMC should apply to all classes, reducing in the subsidy of the residential class by the large power customer class.

5. CMA--CMA supports CLECA's proposed revenue allocation.

6. CAL-SLA--CAL-SLA believes that DRA's revenue allocation proposal is consistent with D.87-12-066, but prefers a one-half EPMC revenue allocation with a 5% cap on increases above the system average percentage change. CAL-SLA opposes CLECA's proposal under which street light customers would receive no percentage increase or decrease in their rates.

While these parties' approaches to a phased-in EPMC revenue allocation vary, their grounds in support of such a revenue allocation do not. Primarily, these parties assert that an EPMC revenue allocation is consistent with current Commission policy and, despite increases over SAPC for the domestic class, must be realized in this rate case in order to achieve a full EPMC revenue allocation for Edison by 1990.

In this regard, DRA is joined by the other parties in arguing that any delay in movement toward EPMC will only mean that

negatively-impacted customer classes will suffer "an even bigger jolt when rates suddenly move 50% or 100% of the way to EPMC." (DRA Opening Brief, at p. 26.) DRA believes that its approach best meets the Commission's goals of (1) achieving full EPMC by 1990, (2) moving rates toward the cost of service, and (3) minimizing negative bill impacts. DRA asserts that, in contrast, Edison's SAPC approach achieves none of these goals by postponing any further movement toward EPMC for over eighteen months (Edison's 1989 ECAC). DRA also believes its approach is preferable to the other EPMC recommendations since a rate cap or present rate floor would distort the true EPMC relationships among ratepayer classes and slow down the progress to EPMC.

CLECA, IU, FEA, and CMA all support the Commission continuing its goal of achieving a fully cost-based revenue allocation for Edison by 1990. All of these parties agree that the movement toward EPMC in this proceeding is necessary to send proper price signals to Edison's customers and to reflect that the adoption of an EPMC-based revenue allocation in Edison's general rate case was not just a one-time occurrence.

These parties share DRA's belief that the best way to achieve an EPMC revenue allocation for Edison by 1990 is to utilize each ECAC proceeding between general rate cases. In this way, according to CLECA, rates can be moved in smaller and more regular increments toward full EPMC allocation. These parties also agree that Edison's proposal is unlikely to achieve full EPMC by 1990.

CLECA, FEA, IU, and CMA also assert that Edison's proposal is a step backward from EPMC. Specifically, each notes that Edison's proposal actually moves all customer classes farther away from EPMC in terms of the dollar distance to EPMC. In the opinion of these parties, this result will make it more difficult to achieve EPMC in 1990 and in turn will increase the rate impact on the residential class in subsequent ECACs. CLECA states that the use of SAPC to spread Edison's proposed increase could result

in an increase of approximately $26 million in the dollar amount by which residential class revenues are below the residential class EPMC revenue requirement. Further, FEA argues that it is the dollar distance from cost-based rates which is what the Commission is trying to eliminate through its goal of moving rates to cost.

IU also notes that its testimony demonstrated that the residential class is the only one of Edison's major customer classes to receive a subsidy and that this subsidy ($252.7 million) continues to be largely paid by Edison's large power customers. IU believes that these figures illustrate the need to take immediate steps toward EPMC in this rate proceeding.

CLECA and CMA dismiss Edison's and TURN's concern regarding the impact of multiple rate increases on residential customers in a short period of time. In this regard, CLECA notes that rate changes in this proceeding are unlikely before October 1, 1988. At that time, according to CLECA, the summer peak usage period would be over and any potential adverse impact on air conditioning loads caused by a rate increase would have been avoided.

This circumstance also means, according to CMA and CLECA, that the 17 to 18% increases for the residential class referenced by Edison would not be in effect for 1988, but only 3 or 4 months of 1988. CMA states that for 1988 as a whole, an additional 5% increase over SAPC for domestic rates in this case would produce an effective increase of only 6.7% above SAPC for the year as a whole. CMA bases this statement on a 5% GRC increase for 8 months coupled with a combined 10% GRC/ECAC increases for 4 months, averaging 6.7% for 12 months.

CMA is also concerned that, if no action is taken toward EPMC at this time, that the next opportunity for such movement will not be 18 months, but actually 24 months from the general rate case decision. CMA bases this argument on the statements contained in the ALJ ruling of May 26, 1988, in R.87-11-012, the Commission's

rulemaking into rate case and fuel offset scheduling. In that ruling, CMA notes, the ALJ proposed a new time schedule for Edison's fuel offset proceedings which would defer the effective date of Edison's next ECAC rate change to the end of 1989. CMA states that, if the final step toward EPMC were to be made at the end of 1990, that rate change could be quite significant since it would coincide with any rate increase authorized in Edison's next general rate case.

CMA also rejects TURN's argument that the distance from EPMC will diminish simply by the Commission recognizing an increase in Edison's marginal energy cost revenues. CMA states that such speculation ignores the potential of offsetting changes in marginal capacity costs and customer costs. Such changes, in CMA's view, would result in a reverse shift of the allocated revenue requirements share to the lower load factor domestic customers. CMA also states that, based on a larger share of total sales and changes in load patterns, updated marginal cost responsibility data show an increasing share of existing marginal costs are allocable to domestic sales.

In addition, CLECA rejects Edison's assertion that the 5% cap set forth in D.87-12-066 was meant to be applicable to all rate increases during the test year. CLECA notes that, when issuing D.87-12-066, the Commission had no way of knowing at the time what amount of revenue increase would be requested by Edison in its 1988 ECAC. In CLECA's view, it makes no sense to suggest that the Commission would foreclose its option to make additional progress toward EPMC when faced with a $400 million increase.

In support of CLECA's revenue allocation, CMA asserts that DRA's approach would perpetuate the existing disproportionate degrees to which other classes support the domestic subsidy. CMA similarly found that FEA's and IU's approach did not result in a significant enough change and retained the existing wide range of subsidization intact.

CAL-SLA joins those parties supporting a phased-in EPMC revenue allocation in this proceeding. CAL-SLA states that, because the street lighting customer's rates are presently the furthest from marginal costs, an EPMC-based revenue allocation in this proceeding is critical. CAL-SLA opposes the proposal of CLECA under which street light customers would receive no percentage increase or decrease and therefore no change in the subsidization by street lighting.

CAL-SLA also states that Edison has erred by not excluding facilities charges from the revenue allocation process. CAL-SLA disagrees with Edison's statements that facilities charges should be excluded only when an EPMC revenue allocation process is imposed. It is CAL-SLA's opinion that the Commission has made no distinction between revenue allocation methods as far as the exclusion of facilities charges. (CAL-SLA citing D.87-12-066, Conclusion of Law 137.) CAL-SLA further notes that facilities charges were excluded from the revenue allocation adopted by the Commission in the interim decision, in this proceeding. (D.88-05-074 at pages 23 and 23a.)

b. Issues Related to Interruptible Credits and Off-Peak Energy Charge

The two other revenue allocation issues addressed by the parties included (1) the treatment of interruptible credits in the revenue allocation process and (2) the level of the off-peak energy rate for rate schedule TOU-8 and the second block energy rate in rate schedules GS-2 and PA-2. The first issue surfaced as a result of the revenue allocations proposed by FEA and IU, while the second issue is a result of different interpretations of the Commission's rate design adopted in D.87-12-066.

With respect to the treatment of interruptible credits in the revenue allocation process, both FEA and IU have proposed EPMC-based revenue allocations in which interruptible credits are excluded from that process. Edison asks the Commission to reject

this approach asserting that only street and area lighting facilities charges were authorized by D.87-12-066 to be excluded from the revenue allocation process. Further, Edison states that consideration of this exclusion is beyond the scope of this proceeding. Specifically, Edison notes that D.87-12-066, as reaffirmed in D.88-04-026, provided that marginal cost revenue responsibility levels should not be relitigated in this ECAC proceeding.

In response to Edison's criticism, IU asserts that its treatment of interruptible credits is not a recalculation of marginal cost revenue responsibility. IU states that its marginal cost revenue responsibility figures are no different than the figures used by other parties in their revenue allocation proposals. According to IU, its interruptible credit adjustments simply involve splitting out "below the line" the interruptible credit portion of large power revenues. IU states that this adjustment is necessary to ensure that large power revenues are shown exclusive of interruptible credits to allow for comparison of firm costs and firm revenues.

FEA concurs with IU that the exclusion of interruptible credits is necessary to overcome Edison's assumption, in determining the marginal cost share for the TOU-8 class, that all customers take firm service. By making this assumption, FEA states that Edison overstates TOU-8 cost responsibility. FEA therefore recommends allocating firm revenue responsibility based on EPMC to all classes and allocating the interruptible credits within the TOU-8 class on a basis parallel to the spread of interruptible credits in the calculation of sales revenue. FEA states that its proposal does not change the marginal costs as established in D.87-12-066, but merely treats interruptible credits in a different fashion.

In this proceeding, DRA proposes to increase the TOU-8 and TOU-GS off-peak energy rates from 5 cents/kWh to 5.2 cents/kWh

based on its Class Equal Percent Change (CEPC) rate design. DRA did not offer a PA-2 rate design, but stated that it should also reflect a CEPC rate design. (Tr. at p. 664.)

In support of its position, DRA argues that if off-peak rates are held constant as on- and mid-peak rates rise, the potential for economic bypass on Edison's system increases. In DRA's opinion, the failure to increase off-peak rates also increases the potential for rate shock in the mid- and on-peak rates. DRA therefore believes that holding the off-peak rate constant at 5 cents/kWh would unduly distort the price relationships established in the general rate case.

With respect to the off-peak energy rate, Edison asserts that this rate for the TOU rate schedules and the second block for GS-2 and PA-2 was set in D.87-12-066 at five cents per kilowatt-hour to ensure a stable rate level. In that decision, Edison notes that the Commission specifically did not employ a percentage relationship between the mid-peak and on-peak levels as assumed by DRA nor did it utilize DRA's proposed EPMC relationship for setting the off-peak rate level. Edison therefore objects to DRA's proposal to increase off-peak energy charges in this proceeding. While D.88-05-074 applied DRA's CEPC rate design to off-peak rates, Edison believes that this action was taken in the mistaken belief that it was consistent with the general rate case decision.

CMA supports Edison's proposed 5 cent/kWh off-peak TOU-8 energy rate. CMA states that as the 5 cent/kWh rate was chosen to provide a stable off-peak rate and to mitigate billing impacts from rate restructuring, it deserves to be maintained at this time without increase. In fact, CMA argues that, examined on a cost basis, the off-peak rate should in fact be lower than 5 cents/kWh. Having been set at higher than EPMC level for non-cost reasons, CMA urges that the rate remain at that level.

CMA also notes that DRA's assertion regarding the need to increase off-peak energy rates to avoid excessive increases to mid-

In our interim order in this proceeding (D.88-05-074), we adopted an SAPC revenue change of 3.7%. In doing so, however, we made clear that adoption of an SAPC revenue allocation in the interim order was "not intended to predetermine the issue of revenue allocation in this proceeding nor preclude the evidentiary showings permitted under D.87-12-066 and D.88-04-026." (D.88-05-074, at p. 24.) Rather, it had been our intent to select a revenue allocation which would minimize the possibility of any single customer class receiving an interim increase greater than its final rate change.

We also concluded that our adoption of an SAPC revenue allocation was not at odds with our stated goal of moving toward an EPMC revenue allocation for Edison. Specifically, we noted that at the time of issuance of D.87-12-066 the Commission had not considered nor anticipated the need for interim rate relief in Edison's 1988 ECAC proceeding.

Against this background, the parties presented the following revenue allocation proposals in this proceeding. These proposals also require consideration of the treatment of interruptible credits and Edison's off-peak energy charge. As our subsequent discussion makes clear, we must now also consider the impact of recent changes in baseline legislation and the current status of the Commission's investigation into ECAC scheduling changes.

1. Parties Positions

a. Basic Revenue Allocation Proposals

In this proceeding, Edison and TURN support a 100% SAPC revenue allocation. Edison states that its proposed SAPC revenue allocation is primarily aimed at mitigating the impact of 1988 revenue increases on residential customers. In support of its position, Edison argues that, if a phased-in EPMC revenue allocation were adopted in this proceeding, additional movement

and on-peak energy rates is only valid with respect to Edison's SAPC revenue allocation. CMA states that DRA did not demonstrate that these disproportionate increases occur under any other proposed revenue allocation.

2. Discussion

Since the issuance of our decisions in Edison's most recent general rate case and even the interim order in this proceeding, several events have occurred which directly impact our determination of the appropriate revenue allocation to be adopted in this proceeding. Specifically, we must consider (1) the significant revenue increase which will result from this decision, (2) the enactment of Senate Bill (SB) 987 amending the baseline statute (Section 739 of the Public Utilities Code) and the implementation of that legislation by the Commission (I.88-07-009), and (3) finally, the Commission's rulemaking to revise the general rate case and fuel offset time schedules (R.87-11-012).

In this decision, we have largely adopted DRA's revenue requirement recommendations. Under these circumstances, it appears that the resulting revenue increase, given subsequent changes to the IER and the addition of other revenue increases, will be no less than $384 million. This sum is, of course, substantially less than the original $628 million requested by Edison in this proceeding, but is still significantly more than the $32.7 million decrease authorized in the general rate case. Such a revenue change will obviously have a significant impact on many of Edison's customers.

As explained earlier in this section, the Commission in adopting an EPMC-based revenue allocation for Edison in D.87-12-066 was faced with a significant shift of the revenue responsibilities of its customer classes. We concluded, however, that it was our goal to continue to move toward and achieve a revenue allocation based on "full EPMC" "as soon as possible.". (D.87-12-066, at p. 262.)

The issue directly raised by Edison's and TURN's support of an SAPC allocation for this ECAC proceeding is how fast and how disruptive does this transition to EPMC needs to be. Edison and TURN express their concern with the rate shock to the domestic group which would result from a 4.9% increase from the general rate case being quickly followed by a potential 12 or 13% increase in this proceeding based on capped EPMC revenue allocation and Edison's proposed revenue requirement. Both seem to infer that delaying further movement to EPMC until Edison's 1989 ECAC will not have any demonstrably negative impact on that process.

While we agree that Edison's domestic customers will face multiple rate increases in a single year, we believe that the "shock" of those increases has been mitigated by several factors. These factors include: (1) the timing of this rate increase in terms of Edison's last general rate case, (2) the ALJ's proposed changes to Edison's ECAC schedule, and (3) the enactment of SB 987. As certain of the interested parties have pointed out, the rate changes resulting from this ECAC are unlikely to occur before October 1, 1988. This date is nine months after the rate changes in the general rate case and follows the summer peak period. Additionally, by issuing an interim order in this proceeding authorizing a 3.7% rate increase for all customer groups, Edison's domestic ratepayers will see a more gradual increase in their rates, rather than one significant rate increase.

With respect to planned changes in Edison's ECAC revision dates, we note, as did CMA, the issuance of an ALJ ruling in R.87-11-012 on May 26, 1988. In that ruling, the ALJ considered a "consensus" document submitted by the major parties to the rulemaking proposing schedules for the utilities' fuel offset proceedings. Additionally, the ALJ stated his agreement with the consensus proposal with the exception of the schedule for Edison.

Because of simultaneous hearings for Edison and SoCal resulting from that schedule, the ALJ proposed having "Edison's

ECAC lag SoCal's ACAP by three months." The proposal had been for Edison's rates to become effective in late September; the change offered by the ALJ would result in this date being postponed to December. This proposal has yet to be adopted by the Commission.

Under these circumstances, CMA has correctly pointed out the potential for a rate change in Edison's 1989 ECAC not occurring until December, 1989, almost two years after the general rate case decision. Although we are concerned with "rate shock" to specific customer groups, it is still our intention to move toward EPMC and to achieve full EPMC for Edison by its next general rate case. Given the possibility of a change in the proposed effective date in Edison's 1989 ECAC to December 1989, achieving full EPMC seems unlikely if some progress is not made in this proceeding. Alternatively, the impact of multiple rate increases at the time of Edison's next general rate case and its 1990 ECAC could impede further movement to EPMC at that time.

TURN has also expressed concern regarding the impact of an EPMC revenue allocation on residential customers using quantities above the baseline amounts. We believe that this concern may be somewhat mitigated by the enactment of SB 987 and our implementation of that legislation in I.88-07-009.

Specifically, we note that the purpose of I.88-07-009 is to provide for the immediate realignment of baseline and nonbaseline residential rates by the start of the 1988-89 heating season or November 1, 1988, consistent with SB 987. These baseline rate changes include deleting the requirement that baseline rates be established at a differential of from 15% to 25% below the system average rate. In establishing baseline rates, amended Section 739 (c)(1) requires the Commission to "avoid excessive rate increases for residential customers, and ... establish an appropriate gradual differential between the rates for the respective blocks of usage." In making these changes, however, the Commission is to assure that the rates are sufficient to enable the

subsidy relationships and reduction of those subsidies by one-third.

4. FEA--FEA proposes that a 20 percent reduction of the dollar deviation from EPMC should apply to all classes, reducing in the subsidy of the residential class by the large power customer class.

5. CMA--CMA supports CLECA's proposed revenue allocation.

6. CAL-SLA--CAL-SLA believes that DRA's revenue allocation proposal is consistent with D.87-12-066, but prefers a one-half EPMC revenue allocation with a 5% cap on increases above the system average percentage change. CAL-SLA opposes CLECA's proposal under which street light customers would receive no percentage increase or decrease in their rates.

While these parties' approaches to a phased-in EPMC revenue allocation vary, their grounds in support of such a revenue allocation do not. Primarily, these parties assert that an EPMC revenue allocation is consistent with current Commission policy and, despite increases over SAPC for the domestic class, must be realized in this rate case in order to achieve a full EPMC revenue allocation for Edison by 1990.

In this regard, DRA is joined by the other parties in arguing that any delay in movement toward EPMC will only mean that negatively-impacted customer classes will suffer "an even bigger jolt when rates suddenly move 50% or 100% of the way to EPMC." (DRA Opening Brief, at p. 26.) DRA believes that its approach best meets the Commission's goals of (1) achieving full EPMC by 1990, (2) moving rates toward the cost of service, and (3) minimizing negative bill impacts. DRA asserts that, in contrast, Edison's SAPC approach achieves none of these goals by postponing any further movement toward EPMC for over eighteen months (Edison's 1989 ECAC). DRA also believes its approach is

utility "to recover a just and reasonable amount of revenue from residential customers as a class". (Id.)

Additionally, SB 987 directs the Commission to use increased revenues resulting from any increase in baseline rates exclusively to reduce rates for service above the baseline quantity. Any significant differential between baseline and nonbaseline rates is not to be eliminated, however, for at least 30 months after the effective date of this bill.

Hearings in I.88-07-009 have been scheduled to commence on August 15, 1988. It is our hope that any rate changes adopted in that proceeding can be reflected in Edison's rates adopted in this proceeding. In order to make the rate change authorized in this decision coincide with the change from the summer to winter residential baseline period, the adopted rates will be made effective October 1, 1988.

Under these circumstances, we believe that it is appropriate to take a further step toward a full EPMC revenue allocation for Edison in this proceeding. D.87-12-066 does not prohibit such a step being taken in this ECAC and, despite other parties' contentions to the contrary, does not limit the percentage increase over the system average percentage change which can occur.

Specifically, Edison has argued that the Commission's 5% cap was an "annual" cap on rate increases. In fact, we find that D.87-12-066 not only did not provide for such a limitation, but makes clear that any revenue allocation adopted by the Commission in subsequent offset proceedings be determined by the circumstances existing at the time of the offset. (D.87-12-066, at p. 262.) In that decision, we also directed Edison and other parties to file SAPC and phased-in EPMC proposals without any limitation on the nature of their phase-in proposals.

Edison may have reached its conclusion based on references in D.87-12-066 to revenue allocation changes in the two years <u>following</u> the test year. These statements would seem to

imply that no revenue allocation changes were intended during the test year (1988).

While this result may have been one for which the Commission had hoped, this expectation is not a reasonable one given the current circumstances of a significant rate increase and changes in the timing of intervening rate changes. Additionally, the fact that the Commission in part foresaw the need to reevaluate revenue allocation is reflected in our providing for consideration of revenue allocation in this proceeding in both D.87-12-066 and D.88-04-026.

We note TURN's arguments regarding changes to marginal energy cost revenue responsibility and speculation regarding future rate increases. In answer to these points, we again note that the issue of marginal cost structure was not to be considered in this proceeding. Based on changes to marginal energy cost revenues alone, we cannot quantify the structure occurring since the last general rate case has been changed to marginal energy costs which requires considerations of other factors as well. It is difficult to believe that this change in revenues alone could have a significant enough effect on marginal energy costs to drastically change the percentage distance of residential rates from EPMC.

With respect to future rate increases, although they may be less than this request, the magnitude of rate increase adopted in this proceeding has the direct effect, as pointed out by many parties, of increasing the discrepancy in actual dollar terms between the revenue responsibilities of the large power and residential classes. We believe that some movement toward EPMC in this proceeding is preferable to permitting that situation to deteriorate.

In reviewing the various proposals of the parties, we therefore believe that a reasonable basis upon which to achieve further movement toward EPMC and mitigate any negative rate impact is a modified version of DRA's methodology. DRA's approach

requires a weighted average of 1/3 EPMC and 2/3 SAPC. We will adopt this basic approach, but modify it to add a 2.5% cap over the system average percentage change for all customer groups. No floors on rate reductions, however, will be required. We believe that this approach has the positive effect of achieving some movement toward EPMC in this proceeding, mitigating rate shock to the domestic customer group, and providing a balanced treatment of all of Edison's customer classes.

Our adopted revenue allocation is shown on the following table. This allocation is based on Edison's total adopted revenue requirement as of October 1, 1988. Details are shown in Appendices B and C. This table also illustrates some of the proposed revenue allocation methodologies.

CMA also rejects TURN's argument that the distance from EPMC will diminish simply by the Commission recognizing an increase in Edison's marginal energy cost revenues. CMA states that such speculation ignores the potential of offsetting changes in marginal capacity costs and customer costs. Such changes, in CMA's view, would result in a reverse shift of the allocated revenue requirements share to the lower load factor domestic customers. CMA also states that, based on a larger share of total sales and changes in load patterns, updated marginal cost responsibility data show an increasing share of existing marginal costs are allocable to domestic sales.

In addition, CLECA rejects Edison's assertion that the 5% cap set forth in D.87-12-066 was meant to be applicable to all rate increases during the test year. CLECA notes that, when issuing D.87-12-066, the Commission had no way of knowing at the time what amount of revenue increase would be requested by Edison in its 1988 ECAC. In CLECA's view, it makes no sense to suggest that the Commission would foreclose its option to make additional progress toward EPMC when faced with a $400 million increase.

In support of CLECA's revenue allocation, CMA asserts that DRA's approach would perpetuate the existing disproportionate degrees to which other classes support the domestic subsidy. CMA similarly found that FEA's and IU's approach did not result in a significant enough change and retained the existing wide range of subsidization intact.

CAL-SLA joins those parties supporting a phased-in EPMC revenue allocation in this proceeding. CAL-SLA states that, because the street lighting customer's rates are presently the furthest from marginal costs, an EPMC-based revenue allocation in this proceeding is critical. CAL-SLA opposes the proposal of CLECA under which street light customers would receive no percentage increase or decrease and therefore no change in the subsidization by street lighting.

A.88-02-016 ALJ/SSM
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SOUTHERN CALIFORNIA EDISON COMPANY ECAC
ADOPTED REVENUE ALLOCATION 1/
EFFECTIVE OCTOBER 1, 1988

CUSTOMER GROUP	SALES 2/ (GWH)	PRESENT RATE REV PRIOR TO INTERIM /3 ($000's)	PRESENT RATE REV /3 /4 ($000's)	TOTAL MC REVS 5/ ($000's)	FULL EPMC ($000's)	(%) INC.	(EDISON) SAPC ($000's)	(%) INC.	(DRA) 2/3 SAPC 1/3 EPMC ($000's)	(%) INC.	EPMC CAPPED AT 5% OVER SAPC ($000's)	(%) INC.	EPMC CAPPED AT 2.5% OVER SAPC ($000's)	(%) INC.	2/3 SAPC 1/3 EPMC 2.5% CAP OVER SAPC /6 ($000's)	ADOPTED CHANGES (%) TOTAL INC.	(%) INC. OVER INTERIM	AVERAGE RATE ($/KWH)
DOMESTIC	20,162	1,726,096	1,789,992	1,611,300	2,084,420	20.7	1,846,926	7.0	1,926,091	11.6	1,933,229	12.0	1,890,078	9.5	1,890,078	9.5	5.6	0.094
SM/MED POWER																		
GS-1	4,187	434,915	451,017	363,200	469,783	8.0	465,305	7.0	466,798	7.3	487,051	12.0	476,178	9.5	471,630	8.4	4.6	0.113
GS-2	18,084	1,560,580	1,618,337	1,223,500	1,585,161	1.6	1,669,638	7.0	1,641,479	5.2	1,650,971	5.8	1,678,976	7.6	1,657,054	4.2	2.4	0.092
LARGE POWER																		
TOU-8:2ND	6,756	540,725	560,745	416,900	539,242	(0.3)	578,509	7.0	565,420	4.6	561,630	3.9	571,157	5.6	570,641	5.5	1.8	0.084
TOU-8:PRI	10,413	746,462	774,099	558,700	722,654	(3.2)	798,622	7.0	775,299	3.6	752,636	0.8	765,424	2.5	780,126	4.5	0.8	0.075
TOU-8:SUB	3,189	185,051	191,992	133,200	172,288	(6.9)	197,982	7.0	189,417	2.4	179,441	(3.0)	182,485	(1.4)	190,989	3.2	(0.5)	0.060
AGRICULTURE	2,073	172,010	178,376	139,600	180,432	5.0	184,053	7.0	182,913	6.3	188,128	9.4	188,353	9.5	184,732	7.4	3.6	0.089
STREETLIGHTING	475	70,321	71,671	20,000	59,724	(15.1)	72,869	3.6	68,488	(2.6)	60,798	(13.5)	61,255	(12.9)	68,656	(2.4)	(4.2)	0.144
TOTAL	65,338	5,436,160	5,636,158	4,468,400	5,813,905	6.9	5,813,905	6.9	5,813,905	6.9	5,813,905	6.9	5,813,905	6.9	5,813,905	6.9	3.2	0.089

1/ Although facilities charges and optional TOU meter charges have been excluded from the revenue allocation process, these amounts have been added to the figures in this table in order to obtain the correct percentage increases and average rate calculations.

2/ ECAC sales figures have not been adjusted for employee discounts.

3/ Present rate revenues include optional TOU meter charges for test year 1988 per SCE general rate case decision D.87-12-066, and differ slightly from interim D.88-05-074. Additional revenues for optional TOU meters will be reflected in attrition per D.87-12-066.
Present rate revenues are adjusted for the Large Power class to reflect the difference between actual interruptible credits and credits allocated on an EPMC basis.

4/ Interim Decision 88-05-074 issued May 25, 1988.

5/ Based on marginal costs from SCE general rate case D.87-12-066. Marginal cost revenue responsibility has been updated for ECAC forecast sales, demand and customers.

6/ Interruptible credits are computed on an EPMC basis, based on D.87-12-066 as modified.

This table reflects that although we are authorizing expense revisions for only the ECAC/AER/ERAM portion of Edison's revenue requirement, we have adopted a new revenue allocation. Under these circumstances, we have two choices for the treatment of base rates: (1) to leave base rates unchanged resulting in Edison's ERAM account becoming susceptible to overcollection because the sales forecast adopted in this proceeding exceeds the sales used in setting the current base rates, or (2) to leave base rate revenue requirement unchanged, except for authorized revenue changes since the interim decision, and revise base rates to reflect the new sales level.

In order to minimize fluctuations in the ERAM account balance, we find that it is reasonable to adopt the second of these options. We have recently adopted this approach in setting ECAC/AER/ERAM rates for PG&E in D.87-12-068. We further note that this rate adjustment has no impact on authorized base rate revenue requirement.

Although Edison's Major Additions Adjustment Clause (MAAC) and Conservation and Load Management Adjustment Clause (CLMAC) rates are not constructed in exactly the same way as base rates, we will also adjust those two rates for the new sales forecast to be consistent with our approach to base rates. The cash flow impacts of this decision are minimal (see footnote 4, Appendix C). By following this approach, all of Edison's rate elements will be determined using the most recently adopted sales forecast.

Finally, we address the treatment of interruptible credits and streetlight facilities charges in the revenue allocation process and the determination of Edison's off-peak energy charge. We find that D.87-12-066 makes clear that "[s]treetlight energy charges, but not facilities charges associated with an end-use, should be included in the revenue allocation process." (D.87-12-066, at p. 442.) We did not intend,

contrary to Edison's conclusion, to limit this exclusion of facilities charges to EPMC-based revenue allocations. We therefore share CAL-SLA's conclusion that the exclusion of streetlight facilities charges is equally appropriate for both SAPC and EPMC revenue allocations.

We do not believe, however, that this proceeding is the appropriate forum for changing the treatment of interruptible credits in the revenue allocation process. Consideration of revenue allocation issues was limited to SAPC or phased-in EPMC proposals. In all other ways, our treatment of marginal costs or a customer's usage patterns were to remain constant with our findings in D.87-12-066. We therefore reject the approach taken by IU and FEA with respect to interruptible credits and suggest that they renew such suggestions in Edison's next general rate case.

With respect to Edison's off-peak energy charge, in D.87-12-066 we rejected DRA's proposal to set the off-peak energy rate at the full EPMC level. Instead, we adopted Edison's proposed 5 cent/kWh off-peak energy charge "to ensure consistency between the TOU-8 and TOU-GS schedules and to mitigate any adverse effect which might result from customers having to change schedules." (D.87-12-066, at p. 324.)

The result of this finding was effectively to insulate the off-peak energy charge from revenue increase changes which would require other charges to be increased toward their EPMC relationships. Our change to this rate resulting from the interim order in this proceeding (D.88-05-074) was, as Edison observes, inadvertent.

We therefore find that the off-peak energy charge contained in Edison's time of use schedules listed in Appendix D to this decision should be returned to the 5-cent/kWh level, but all other charges should be changed in accordance with DRA's proposed

CEPC rate design.[1] As we found in D.88-05-074, this rate design proposed by DRA is consistent with D.87-12-066 and D.88-04-026.

Findings of Fact

1. Edison's current ECAC marks the beginning of the regular annual updating in ECAC of key components in the calculation of prices paid for power sold to the utility by qualifying facilities.

2. Because the ECAC proceeding is intended to reflect the most up-to-date data in any adopted forecast expense or IER, it was reasonable for Edison and DRA to update their recommendations in this proceeding.

3. It is the Commission's goal to develop both a utility's rates and QF prices on a consistent basis.

4. There is no evidence in this proceeding that the ELFIN production cost computer model produces unreasonable forecast results or results substantially at odds with the FPP spreadsheet program.

5. The use of a production cost model to forecast both revenue requirements and components of variable QF payments best achieves the Commission's regulatory goals, reflects the growing reliance on computer modeling in ratemaking, and ensures consistency in establishing both utility rates and QF payments.

6. Based on the preceding findings, it is reasonable to adopt DRA's recommendation to use ELFIN to develop both Edison's revenue requirement and its IER.

7. Due to the adoption of most of DRA's recommended forecast assumptions, it is necessary only for DRA to "re-run" its ELFIN computer model for revenue requirements purposes during the comment phase.

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1 Our application of DRA's CEPC rate design in the interim order D.88-05-074 effectively requires a reduction in the off-peak energy charge adopted in that order to the 5-cent/kWh level.

8. Because the Commission did not uniformly adopt the assumptions of any single party with respect to the IER calculation, it will be necessary for the parties to "re-run" ELFIN during the comment period to provide their final recommendations.

9. It is reasonable to consider the revised IER and revenue requirement recommendations presented during the comment period as late-filed exhibits and require the parties offering these recommendations to serve each other with all supporting work papers at the same time their comments are filed.

10. The adopted procedure for considering revised IER and recommendations during the comment period, necessitated by time constraints in this proceeding, is appropriate given that all parties have used the same model and have had an equal opportunity through many days of workshops and hearing to discuss and cross-examine each party's use of ELFIN.

11. It is reasonable to adopt the agreement reached by Edison and DRA on the issues of sales forecast, Edison hydro generation, nuclear generation and expense, and the estimated ECAC and ERAM account balances as each is based on the most recent data and surveys.

12. The Commission remains committed to the reinstitution of Edison's AER at a 10% level.

13. It is premature to grant the suspension of Edison's AER beginning June 1, 1989, based solely on the possibility of an ECAC schedule for Edison in R.87-11-012 that varies from Edison's current schedule.

14. Edison should renew its request to suspend its AER in future ECAC proceedings only when and if circumstances warranting its suspension actually exist.

15. Inconsistencies in Edison's approach in forecasting its gas price, as well as an exaggerated response to seasonal curtailments, undermine the reliability of Edison's forecast.

16. Because DRA considered all of the elements necessary to provide a reasonable level of gas generation expense and developed a reasonable gas price forecast, it is reasonable to adopt DRA's forecast of this expense item.

17. It is the Commission's intention to maintain consistency in the forecasts of both gas and oil expenses with respect to the components which these forecasts share in common.

18. DRA has made reasonable assumptions concerning the level of gas curtailment which Edison can anticipate this winter.

19. DRA's forecast 15-day gas curtailment period, reflected in both its gas and oil generation expense forecasts, is reasonable.

20. DRA's well-supported independent forecast of LSFO oil prices is reasonable.

21. Having found reasonable DRA's estimates of the two components determining oil generation expense, it is reasonable to adopt DRA's forecast for this expense item of $24.8 million for the forecast period.

22. DRA's and Edison's agreement on the quantity of QF power and the capacity factors projected for the four large QF projects is a reasonable compromise of the forecasts presented and should be adopted.

23. DRA has established and Edison has recognized the need to develop better records reflecting the status of each of Edison's QF contracts and to provide this data in a timely fashion to DRA.

24. To improve Edison's QF record-keeping, DRA has proposed a reasonable approach requiring Edison to provide all QFs with a written data request regarding their operational data and to make such data available to DRA with its ECAC data response each year.

25. To protect Edison's ratepayers and ensure accurate representation of QFs in Edison's resource mix, it is necessary to specifically direct the completion of DRA's proposed survey, referenced in the above finding, by Edison's next ECAC.

Given the possibility of a change in the proposed effective date in Edison's 1989 ECAC to December 1989, achieving full EPMC seems unlikely if some progress is not made in this proceeding. Alternatively, the impact of multiple rate increases at the time of Edison's next general rate case and its 1990 ECAC could impede further movement to EPMC at that time.

TURN has also expressed concern regarding the impact of an EPMC revenue allocation on residential customers using quantities above the baseline amounts. We believe that this concern has been somewhat mitigated by the enactment of SB 987 and our implementation of that legislation in I.88-07-009.

Specifically, the purpose of I.88-07-009 is to provide for the immediate realignment of baseline and nonbaseline residential rates by the start of the 1988-89 heating season or November 1, 1988, consistent with SB 987. Today the Commission issues its first decision in that investigation. In that order, we adopt the stipulation of Edison, DRA, and TURN to realign Edison's baseline and Tier II residential rates consistent with SB 987. Specifically, this stipulation provides that Edison's Tier II rate be reduced with the resulting shortfall in revenue offset by a modest increase in the base line rate. Under this stipulation, Edison's base line rate will rise from 85% to 87% of the system average rate.

Consistent with this order and SB 987, it is reasonable to direct Edison to make the rate changes required by that decision and reflected in Appendix D of this order effective concurrently with the ECAC revenue increase authorized in this decision. To ensure a rate change that coincides with the seasonal rate changes experienced by most of Edison's customers and to comply with the November 1, 1988, implementation date of SB 987, the rates adopted in this proceeding will be made effective October 1, 1988.

Under these circumstances, we believe that it is appropriate to take a further step toward a full EPMC revenue

26. Given the adoption of DRA's gas price forecast and approval of DRA's use of ELFIN to determine revenue requirement, the final firm purchase power expense level should be closer to that forecasted by DRA than by Edison.

27. During the comment period, DRA will be required to re-examine its firm purchase power forecast to determine the change in revenue impact, if any, caused by any change to its recommended IER resulting from the assumptions adopted in this decision.

28. CCC/CSC failed to adequately demonstrate that a seven-month period of zero-availability of PNW economy energy power is likely to occur during the forecast period.

29. The three-month period of zero-availability of economy energy power projected by DRA and Edison is a reasonable forecast of the future availability of PNW power.

30. The differences between Edison's and DRA's non-firm power purchases and expense are largely attributable to the differences in the parties' gas price forecasts and DRA's use of ELFIN to determine Edison's revenue requirement.

31. Given the adoption of DRA's forecast gas price, PNW economy energy availability, and use of the ELFIN model for determining Edison's revenue requirement, it is reasonable to adopt DRA's forecast of PNW economy energy availability and expense.

32. Based on the adoption of DRA's gas price forecast and its use of the ELFIN model to develop Edison's revenue requirement, it is reasonable to adopt DRA's forecast of PSW economy energy availability and expense.

33. While there is insufficient support in this record to adopt a ceiling on PSW economy energy availability, the parties can continue to explore the efficacy of "hardwiring" the ELFIN model in the IER workshops held in future ECACs.

34. The difference between Edison's and DRA's coal generation expense forecasts is attributable to different gas prices and ELFIN dispatch of Mohave.

allocation for Edison in this proceeding. D.87-12-066 does not prohibit such a step being taken in this ECAC and, despite other parties' contentions to the contrary, does not limit the percentage increase over the system average percentage change which can occur.

Specifically, Edison has argued that the Commission's 5% cap was an "annual" cap on rate increases. In fact, we find that D.87-12-066 not only did not provide for such a limitation, but makes clear that any revenue allocation adopted by the Commission in subsequent offset proceedings be determined by the circumstances existing at the time of the offset. (D.87-12-066, at p. 262.) In that decision, we also directed Edison and other parties to file SAPC and phased-in EPMC proposals without any limitation on the nature of their phase-in proposals.

Edison may have reached its conclusion based on references in D.87-12-066 to revenue allocation changes in the two years <u>following</u> the test year. These statements would seem to imply that no revenue allocation changes were intended during the test year (1988).

While this result may have been one for which the Commission had hoped, this expectation is not a reasonable one given the current circumstances of a significant rate increase and changes in the timing of intervening rate changes. Additionally, the fact that the Commission in part foresaw the need to reevaluate revenue allocation is reflected in our providing for consideration of revenue allocation in this proceeding in both D.87-12-066 and D.88-04-026.

We note TURN's arguments regarding changes to marginal energy cost revenue responsibility and speculation regarding future rate increases. In answer to these points, we again note that the issue of marginal cost structure was not to be considered in this proceeding. Based on changes to marginal energy cost revenues alone, we cannot quantify changes to the marginal cost structure occurring since the last general rate case. It is difficult to

35. Given the adoption of DRA's forecast gas price and its use of ELFIN to determine Edison's revenue requirement, it is reasonable to adopt DRA's forecast of coal generation and expense.

36. DRA's and Edison's agreement on the coal inventory level and carrying costs is reasonable.

37. There is insufficient evidence in this record to support the changes in circumstance which Edison asserts require a fuel oil inventory level greater than the level adopted in its 1987 ECAC.

38. It is reasonable to adopt DRA's forecast of a 4.4 billion barrel fuel oil inventory which maintains the inventory level adopted for Edison in D.87-11-013.

39. The difference between DRA's and Edison's fuel oil inventory carrying costs is attributable to differences in their forecast fuel oil inventory levels.

40. Having adopted DRA's fuel oil inventory level for the 1988 forecast period, it is reasonable to adopt DRA's fuel oil inventory carrying costs.

41. Consistent with D.87-11-013, it is reasonable to adopt the same ratemaking treatment for fuel oil inventory carrying costs, variations from adopted levels, and gains or losses as adopted in that decision.

42. The fact that different fuel oil inventory carrying cost procedures might be adopted for PG&E does not necessarily warrant or require their mandatory application to Edison.

43. In D.87-12-066, the Commission transferred the rate recovery of coal and nuclear inventory carrying costs from base rates to ECAC rates effective January 1, 1988, and directed that they be included 100 percent in the ECAC balancing account.

44. In D.87-12-069 in SDG&E's 1987 ECAC, the Commission declined to adopt DRA's "lump sum" approach for fuel oil inventory carrying costs.

45. Given the Commission's continuation of a memorandum account for fuel oil inventory carrying costs, it is reasonable to

believe that the change in revenues alone, however, could have a significant enough effect on marginal energy costs to drastically change the percentage distance of residential rates from EPMC.

With respect to future rate increases, although they may be less than this request, the magnitude of rate increase adopted in this proceeding has the direct effect, as pointed out by many parties, of increasing the discrepancy in actual dollar terms between the revenue responsibilities of the large power and residential classes. We believe that some movement toward EPMC in this proceeding is preferable to permitting that situation to deteriorate.

In reviewing the various proposals of the parties, we therefore believe that a reasonable basis upon which to achieve further movement toward EPMC and mitigate any negative rate impact is a modified version of DRA's methodology. DRA's approach requires a weighted average of 1/3 EPMC and 2/3 SAPC. We will adopt this basic approach, but modify it to add a 2.5% cap over the system average percentage change for all customer groups. No floors on rate reductions, however, will be required. We believe that this approach has the positive effect of achieving some movement toward EPMC in this proceeding, mitigating rate shock to the domestic customer group, and providing a balanced treatment of all of Edison's customer classes.

Our adopted revenue allocation is shown on the following table. This allocation is based on Edison's total adopted revenue requirement as of October 1, 1988. Details are shown in Appendices B and C. This table also illustrates some of the proposed revenue allocation methodologies.

to create a similar account for nuclear fuel and coal inventory carrying costs and to direct Edison to include 100% of its adopted nuclear fuel and coal inventory carrying costs in ECAC.

46. It is reasonable to adopt DRA's recommended franchise fees and uncollectible accounts expense and resale accounts allocation based on the adoption of DRA's other forecast recommendations.

47. The workshops ordered by D.87-12-066 and held before the hearings in this forecast phase has greatly enhanced consideration of the many complex issues now included in ECAC and should be continued.

48. Having had the opportunity to review each other's recommendations, it is reasonable to adopt the parties' stipulation of an ERI value of 0.43 for Edison's forecast phase.

49. The procedures followed in this proceeding, including the IER workshops, the forecast phase hearings, and presentation during the comment phase of ELFIN model runs based on our adopted forecasts and assumptions related to Edison's revenue requirement and IER, have provided all parties a full and fair opportunity to litigate the issues in this proceedings.

50. The record in this proceeding supports the adoption of values, as opposed to methodologies, for the assumptions in dispute and the Commission's consideration during the comment phase of IER recommendations based on those values.

51. There is insufficient evidence in this record that any of the parties to this proceeding used the ELFIN model in an inappropriate way or applied poor judgment in reviewing ELFIN results for reasonableness.

52. Sole reliance on the past, and specifically, a single recorded IER, is not appropriate in any forecasting effort.

53. Factual matter or expert opinion upon which a party intends the Commission to rely as support for or a challenge to a

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SOUTHERN CALIFORNIA EDISON COMPANY ECAC
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STREETLIGHTING	475	70,321	71,671	20,000	59,714	(15.1)	72,856	3.6	68,475	(2.6)	60,789	(13.6)	61,266	(12.9)	68,643	(2.4)	(4.2)	0.144
TOTAL	65,338	5,436,160	5,636,159	4,468,400	5,811,642	6.9	5,811,642	6.9	5,811,642	6.9	5,811,642	6.9	5,811,642	6.9	5,811,642	6.9	3.1	0.089

1/ Although facilities charges and optional TOU meter charges have been excluded from the revenue allocation process, these amounts have been added to the figures in this table in order to obtain the correct percentage increases and average rate calculations. Facilities charges and TOU meter charges are expressed in thousands for the following classes: $273.6 for domestic; $30.6 for GS-2; $65.3 for agriculture; $33,855.2 for streetlighting.

2/ ECAC sales figures have not been adjusted for employee discounts; fringe and Sequoia sales have been excluded.

3/ Present rate revenues include optional TOU meter charges for test year 1988 per SCE general rate case decision D.87-12-066, and differ slightly from interim D.88-05-074. Additional revenues for optional TOU meters will be reflected in attrition per D.87-12-066. Present rate revenues are adjusted for the Large Power class to reflect the difference between actual interruptible credits and credits allocated on an EPMC basis.

4/ Interim Decision 88-05-074 issued May 25, 1988.

5/ Based on marginal costs from SCE general rate case D.87-12-066. Marginal cost revenue responsibility has been updated for ECAC forecast sales, demand and customers.

6/ Interruptible credits are computed on an EPMC basis, based on D.87-12-066 as modified. Revenue deficiency from capping is spread to other classes on a 2/3 SAPC, 1/3 EPMC basis.

particular position is evidentiary in nature and should not be presented in a post-hearing brief.

54. The revision of IER recommendations during the comment period is distinguishable from CCC/CSC's inclusion of sensitivity results in its brief for the following reasons: (1) each party will have the same opportunity to present their recommendations at the same time and under the same circumstances, (2) each of these submissions will be accorded the same status (late-filed exhibit), (3) the same assumptions will be used, (4) supporting work papers will be served on each party performing a model run, and (5) each party will have the opportunity to address the revised recommendations in their comment responses.

55. A "substitute unit," as referenced in D.88-03-079, is a "new" resource added in response to the absence of short-run QFs and not an "existing" unit returned from cold standby to fill an intermittent loss of capacity.

56. It is reasonable for those performing a "QFs Out" run to return cold standby units to service in response to a shortage in capacity.

57. To mirror actual system operations, the standby units reflected in a "QFs Out" run should be those which should actually be used to respond to intermittent capacity shortfalls, and their inclusion in this run should be limited to the actual period of time in which the capacity shortage is forecast.

58. CCC/CSC has demonstrated the reasonableness of including Etiwanda 12 and San Bernardino 12 as standby units in the "QFs Out" run for the two-month period in which a capacity shortage is forecast and valuing as-available capacity at 100% during this same period.

59. In forecasting Edison's system operations, it is reasonable to reflect the "probability" of forced outages in ELFIN runs and, in turn, to de-rate capacity for forced outages as well as maintenance.

This table reflects that although we are authorizing expense revisions for only the ECAC/AER/ERAM portion of Edison's revenue requirement, we have adopted a new revenue allocation. Under these circumstances, we have two choices for the treatment of base rates: (1) to leave base rates unchanged resulting in Edison's ERAM account becoming susceptible to overcollection because the sales forecast adopted in this proceeding exceeds the sales used in setting the current base rates, or (2) to leave base rate revenue requirement unchanged, except for authorized revenue changes since the interim decision, and revise base rates to reflect the new sales level.

In order to minimize fluctuations in the ERAM account balance, we find that it is reasonable to adopt the second of these options. We have recently adopted this approach in setting ECAC/AER/ERAM rates for PG&E in D.87-12-068. We further note that this rate adjustment has no impact on authorized base rate revenue requirement.

Although Edison's Major Additions Adjustment Clause (MAAC) and Conservation and Load Management Adjustment Clause (CLMAC) rates are not constructed in exactly the same way as base rates, we will also adjust those two rates for the new sales forecast to be consistent with our approach to base rates. The amortization rates included in ECAC for the Chevron Settlement, the Uranium Contract Termination, the LSFO Inventory Writedown will also be adjusted to reflect the new sales forecast adopted in this decision. The cash flow impacts of this decision are minimal (see footnote 4, Appendix C). By following this approach, all of Edison's rate elements will be determined using the most recently adopted sales forecast.

Finally, we address the treatment of interruptible credits and streetlight facilities charges in the revenue allocation process and the determination of Edison's off-peak energy charge. We find that D.87-12-066 makes clear that

60. Given the time constraints and procedures adopted for this ECAC, it is not reasonable to adopt a methodology for determining and adjustment the commit target variable.

61. The record, which includes reasonable approaches to determining commit target variables, is sufficient to permit the Commission to adopt specific comit target values in this proceeding and, with the adoption of DRA's resource mix assumptions, supports the adoption of DRA's commit target values for the forecast period.

62. For consistency between utilities with standard offer contracts, it is reasonable to apply to Edison the same approach adopted for PG&E in D.86-10-045 for determining fixed gas costs.

63. It is reasonable to reflect avoided gas costs in QF energy payments consistent with the findings of D.88-07-024.

65. In recent Edison's recent general rate case, the Commission has indicated its intent to move toward an EPMC revenue allocation for Edison "as soon as possible." (D.87-12-066, at p. 262.)

65. Recent decisions make clear the Commission's intent to consider a further phase-in of an EPMC revenue allocation for Edison in this proceeding, as well as proposals for an SAPC revenue allocation.

66. Although Edison's domestic customers will face multiple rate increases this year, the "shock" of these increases being allocated on a phased-in EPMC basis has been mitigated by the following: (1) the timing of this rate increase in terms of Edison's last general rate case, (2) the ALJ's proposed changes in Edison's ECAC scheduling, and (3) the enactment of SB 987.

67. The circumstances listed in the above finding, which also suggest the timeliness of a further movement toward EPMC in this proceeding, have produced the following results have occurred: (1) the rate change adopted in this decision will follow the general rate case by nine months and will not include the summer peak period, (2) the issuance of an interim order in this

"[s]treetlight energy charges, but not facilities charges associated with an end-use, should be included in the revenue allocation process." (D.87-12-066, at p. 442.) We did not intend, contrary to Edison's conclusion, to limit this exclusion of facilities charges to EPMC-based revenue allocations. We therefore share CAL-SLA's conclusion that the exclusion of streetlight facilities charges is equally appropriate for both SAPC and EPMC revenue allocations.

We do not believe, however, that this proceeding is the appropriate forum for considering an alternative method of treating interruptible credits in the revenue allocation process. Consideration of revenue allocation issues was limited to SAPC or phased-in EPMC proposals. In all other ways, our treatment of marginal costs or a customer's usage patterns was to remain constant with our findings in D.87-12-066. We therefore will not adopt the alternative approach taken by IU and FEA with respect to interruptible credits, but suggest that the parties renew such suggestions in Edison's next general rate case.

With respect to Edison's off-peak energy charge, in D.87-12-066 we rejected DRA's proposal to set the off-peak energy rate at the full EPMC level. Instead, we adopted Edison's proposed 5 cent/kWh off-peak energy charge "to ensure consistency between the TOU-8 and TOU-GS schedules and to mitigate any adverse effect which might result from customers having to change schedules." (D.87-12-066, at p. 324.)

The result of this finding was effectively to insulate the off-peak energy charge from revenue increase changes which would require other charges to be increased toward their EPMC relationships. Our change to this rate resulting from the interim order in this proceeding (D.88-05-074) was, as Edison observes, inadvertent.

We therefore find that the off-peak energy charge contained in Edison's time of use schedules listed in Appendix D to

proceeding will result in more gradual increases in domestic rates during this year, (3) the ALJ's proposed schedule for Edison's 1989 ECAC could result in a rate change in the Edison's next ECAC at least 24 months after issuance of the general rate case, and (4) changes in baseline legislation resulting from SB 987 could result in providing some rate relief to Edison's Tier II residential customers.

68. The magnitude of rate increase adopted in this proceeding has the direct effect of increasing the discrepancy in actual dollar terms between the revenue responsibilities of the large power and residential classes.

69. Based on the preceding findings, it is appropriate to take a further step toward a full EPMC revenue allocation for Edison in this proceeding.

70. D.87-12-066 does not prohibit a further step toward EPMC being taken in those proceeding nor does it limit the percentage increase over the system average percentage change which can occur.

71. A reasonable basis upon which to achieve further movement toward EPMC, mitigate rate shock to the domestic customer group, and provide a balanced treatment of all of Edison's customer classes is to adopt a modified version of DRA's proposed revenue allocation.

72. It is reasonable to adopt a revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all customer groups, but with no floor on rate reductions.

73. It is reasonable to make the rate change authorized in this decision coincide with the change from the summer to winter residential baseline period.

74. In order to minimize fluctuations in the ERAM account balance, it is reasonable to leave base rate revenue requirement unchanged, except for authorized revenue changes since the interim decision, and revise base rates to reflect the new sales level.

75. It is reasonable to adjust Edison's MAAC and CLMAC rates for the new sales forecast to be consistent with the adopted approach for adjusting base rates.

76. In D.87-12-066, the Commission did not intend to limit the exclusion of street light facilities charges from the revenue allocation process to EPMC-based revenue allocations.

77. It is equally appropriate to exclude street light facilities charges from both SAPC and EPMC revenue allocations.

78. This proceeding is not the appropriate forum for changing the treatment of interruptible credits in the revenue allocation process.

79. Consistent with our approach in D.87-12-066, interruptible credits should not be excluded at this time from the revenue allocation process.

80. In D.87-12-066, the Commission intended to insulate the off-peak energy charge included in Edison's time-of-use schedules from revenue increase changes which would require other charges to be increased toward their EPMC relationships.

81. The off-peak energy charge contained in Edison's time-of-use schedules listed in Appendix D to this decision should be returned to the 5-cent/kWh level approved in D.87-12-066 following its inadvertent increase in D.88-05-074.

82. Except for the off-peak energy charge referenced above, consistent with D.87-12-066 and D.88-04-027, all other charges should be changed in accordance with DRA's CEPC rate design.

Conclusions of Law

1. In this proceeding, it is reasonable to adopt DRA's recommendation to use the ELFIN production cost model to develop both Edison's revenue requirement and its IER.

2. During the comment period following issuance of the ALJ proposed decision, DRA should "re-run" its ELFIN model based on the adopted forecast expenses, resource mix, and IER assumptions to

produce the final revenue requirement to be adopted in this proceeding.

3. During the comment period following issuance of the ALJ proposed decision, Edison, DRA, and CCC/CSC should "re-run" the ELFIN model based on the input assumptions and modeling conventions adopted in this decision to produce their final LER recommendations.

4. The revised revenue requirement and LER recommendations presented during the comment period in this proceeding should be considered late-filed exhibits and should be supported by work papers served on all parties making ELFIN runs during the comment period.

5. The agreement reached by Edison and DRA on the issues of sales forecast, Edison hydro generation, nuclear generation and expense, and the estimated ECAC and ERAM account balances should be adopted.

6. The temporary suspension in D.88-05-074 of Edison's AER should be ended by this decision and the AER reinstituted at a 10% level.

7. DRA's gas price forecast is reasonable and should be adopted.

8. DRA's gas generation expense forecast of $613.25 million is reasonable and should be adopted.

9. Consistency should be maintained in the forecasts of both gas and oil expenses with respect to the components which these forecasts share in common.

10. DRA's oil general expense forecast of $24.8 million is reasonable and should be adopted.

11. DRA's and Edison's agreement on the quantity of QF power and the capacity factors projected for the four large QF projects is reasonable and should be adopted.

12. In Edison's future ECAC proceedings, Edison should be required to provide all QFs with a written data request, consistent

with the survey and timetable proposed by DRA, and provide the resulting data to DRA with its ECAC data response.

13. As part of "re-running" ELFIN during the comment period for revenue requirement purposes, DRA should re-examine its firm purchase power forecast to determine the change in revenue impact, if any, caused by any change to its recommended IER resulting from the assumptions adopted in this decision.

14. The final firm purchase power expense level should be closer to that forecasted by DRA than by Edison.

15. DRA's forecast of PNW economy energy availability and expense is reasonable and should be adopted.

16. DRA's forecast of PSW economy energy availability and expense is reasonable and should be adopted.

17. DRA's forecast of coal generation and expense is reasonable and should be adopted.

18. DRA's and Edison's agreement on the coal inventory level and carry costs is reasonable and should be adopted.

19. DRA's forecast of a 4.4 billion barrel fuel oil inventory is reasonable and should be adopted.

20. DRA's forecast of fuel oil inventory carrying costs is reasonable and should be adopted.

21. The ratemaking treatment announced in D.87-11-013 related to the establishment of a memorandum account for fuel oil inventory carrying costs should be continued for those costs and similar memorandum accounts created for nuclear fuel carrying costs and coal inventory carrying costs.

22. Edison should include 100% of its adopted nuclear fuel carrying costs and coal inventory carrying costs in ECAC.

23. DRA's recommended franchise fees and uncollectible accounts expense and resale accounts allocation is reasonable and should be adopted.

24. The parties' stipulated ERI value of 0.43 is reasonable and should be adopted.

25. The "QFs Out" run performed in this proceeding to develop Edison's final IER should reflect the return to service of Etiwanda 12 and San Bernardino 12 as cold standby units for the two-month period in which a capacity shortage is forecast and should value as-available capacity at 100% for the same time period.

26. In determining Edison's final IER, Edison's system capacity should be de-rated for forced outages and maintenance in the manner proposed by DRA and Edison.

27. DRA's proposed commit target values for the forecast period are reasonable and should be adopted.

28. DRA's proposed approach to determining Edison's fixed gas costs is reasonable and should be adopted.

29. Avoided gas costs should be reflected in QF energy payments in a manner consistent with D.88-07-024.

30. A revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all customer groups is reasonable and should be adopted in this proceeding.

31. The rate change authorized in this decision should coincide with the change from the summer to winter residential baseline period.

32. The base rate revenue requirement should remain unchanged in this proceeding except for authorized revenue changes since the interim decision (D.88-05-024).

33. Edison's MAAC, CLMAC, and base rates should be revised in this proceeding to reflect the new, adopted sales level.

34. Street light facilities charges should be excluded from both SAPC and EPMC revenue allocations.

35. The Commission's treatment of interruptible credits in the revenue allocation process should not be altered in this proceeding.

31. The differences between Edison's and DRA's non-firm power purchases and expense are largely attributable to the differences in the parties' gas price forecasts and DRA's use of ELFIN to determine Edison's revenue requirement.

32. Given the adoption of DRA's forecast gas price, PNW economy energy availability, and use of the ELFIN model for determining Edison's revenue requirement, it is reasonable to adopt DRA's forecast of PNW economy energy availability and expense.

33. Based on the adoption of DRA's gas price forecast and its use of the ELFIN model to develop Edison's revenue requirement, it is reasonable to adopt DRA's forecast of PSW economy energy availability and expense.

34. While there is insufficient support in this record to adopt a ceiling on PSW economy energy availability, the parties can continue to explore the efficacy of "hardwiring" the ELFIN model in the IER workshops held in future ECACs.

35. The difference between Edison's and DRA's coal generation expense forecasts is attributable to different gas prices and ELFIN dispatch of Mohave.

36. Given the adoption of DRA's forecast gas price and its use of ELFIN to determine Edison's revenue requirement, it is reasonable to adopt DRA's forecast of coal generation and expense.

37. DRA's and Edison's agreement on the coal inventory level and carrying costs is reasonable.

38. There is insufficient evidence in this record to support the changes in circumstance which Edison asserts require a fuel oil inventory level greater than the level adopted in its 1987 ECAC.

39. It is reasonable to adopt DRA's forecast of a 4.4 million barrel fuel oil inventory which maintains the inventory level adopted for Edison in D.87-11-013.

40. The difference between DRA's and Edison's fuel oil inventory carrying costs is attributable to differences in their forecast fuel oil inventory levels.

36. The off-peak energy charge contained in Edison's time-of-use schedules listed in Appendix D to this decision should be 5-cents/kWh.

37. Except for the off-peak energy charges contained in the schedules listed in Appendix D, all other charges should be changed as a result of the revenue increased authorized in this decision in accordance with DRA's CEPC rate design.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized to increase its Energy Cost Adjustment Clause (ECAC) revenue requirement by the amount reflected in the late-filed revenue requirement exhibit to be submitted by the Commission's Division of Ratepayer Advocates (DRA) during the comment period following the issuance of the proposed decision of the Administrative Law Judge (ALJ). This exhibit shall reflect a further ELFIN production cost model run by DRA including all of the forecast expense and resource mix assumptions adopted in this decision, as well as DRA's revised IER presented during the comment period. The resulting revenue requirement is not likely to differ substantially from DRA's currently proposed increase of $384 million, which consists of an increase of $389 million in ECAC, an increase of $37 million in the Annual Energy Rate (AER), and a decrease of $42 million in the Electric Revenue Adjustment Mechanism (ERAM).

2. The temporary suspension of Edison's AER adopted in D.88-05-024 shall be lifted, and Edison's AER shall be reinstituted at the 10% level.

3. Edison's base rate revenue requirement shall remain unchanged except for authorized revenue changes since the interim decision, but Edison's base rates shall be revised to reflect the sales level adopted in this proceeding. Edison's Major Additions

41. Having adopted DRA's fuel oil inventory level for the 1988 forecast period, it is reasonable to adopt DRA's fuel oil inventory carrying costs.

42. Consistent with D.87-11-013, it is reasonable to adopt the same ratemaking treatment for fuel oil inventory carrying costs, variations from adopted levels, and gains or losses as adopted in that decision.

43. The fact that different fuel oil inventory carrying cost procedures might be adopted for PG&E does not necessarily warrant or require their mandatory application to Edison.

44. In D.87-12-066, the Commission transferred the rate recovery of coal and nuclear inventory carrying costs from base rates to ECAC rates effective January 1, 1988 and directed that they be included 100 percent in the ECAC balancing account.

45. In D.87-12-069 in SDG&E's 1987 ECAC, the Commission declined to adopt DRA's "lump sum" approach for fuel oil inventory carrying costs.

46. Given the Commission's continuation of a memorandum account for fuel oil inventory carrying costs, it is reasonable to to create a similar account for nuclear fuel and coal inventory carrying costs for later potential recovery through ECAC and to direct Edison to include 100% of its adopted nuclear fuel and coal inventory carrying costs in ECAC.

47. It is reasonable to allow Edison to finance its nuclear fuel inventory carrying costs based on an interest rate which is a blend of short- and intermediate-term debt rates.

48. It is reasonable to adopt DRA's recommended methodology for calculating franchise fees and uncollectible accounts expense and resale accounts allocation based on the adoption of DRA's other forecast recommendations.

49. The workshops ordered by D.87-12-066 and held before the hearings in this forecast phase have greatly enhanced consideration

Adjustment Clause (MAAC) rates, and Conservation and Load Management Adjustment Clause rates shall similarly be revised to reflect the new sales level. (See, Appendix C to this decision.)

4. On or after the effective date of the final order in this proceeding, and at least 3 days prior to their effective date, Edison shall file revised tariff schedules for electric rates reflecting the revenue increase authorized by the final order. To coincide with the change from the summer to winter residential baseline period, the revised tariff schedules shall become effective on October 1, 1988, and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

5. It is necessary for Edison, DRA, and the California Cogeneration Council and the Cogenerators of Southern California (CCC/CSC) to present revised Incremental Energy Rate (IER) recommendations using the assumptions and modeling conventions adopted in this proceeding as inputs to the ELFIN production cost model. In making these further ELFIN runs, the assumptions to which the parties agreed prior to hearing shall remain unchanged. The parties revised recommendations shall be made late-filed exhibits in this proceeding.

6. The parties making ELFIN runs during the comment period to develop IER (Edison, DRA, and CCC/CSC) recommendations shall be required to serve each other with all supporting work papers at the same time their comments are filed. DRA shall serve the work papers supporting its final revenue requirement recommendation on Edison and CCC/CSC.

7. In the manner proposed by DRA, Edison shall be required to provide all qualifying facilities (QFs) with a written data request regarding the QFs' operational data and to make such data available to DRA each year with Edison's ECAC data response.

8. The ratemaking treatment announced in D.87-11-013 involving the establishment of a memorandum account for Edison's

of the many complex issues now included in ECAC and should be continued.

50. Having had the opportunity to review each other's recommendations, it is reasonable to adopt the parties' stipulation of an ERI value of 0.43 for Edison's forecast phase.

51. The procedures followed in this proceeding, including the IER workshops, the forecast phase hearings, and presentation during the comment phase of ELFIN model runs based on our adopted forecasts and assumptions related to Edison's revenue requirement and IER, have provided all parties a full and fair opportunity to litigate the issues in this proceedings.

52. The record in this proceeding supports the adoption of values, as opposed to methodologies, for the assumptions in dispute and the Commission's consideration during the comment phase of IER recommendations based on those values.

53. There is insufficient evidence in this record that any of the parties to this proceeding used the ELFIN model in an inappropriate way or applied poor judgment in reviewing ELFIN results for reasonableness.

54. Sole reliance on the past, and specifically, a single recorded IER, is not appropriate in any forecasting effort.

55. Factual matter or expert opinion upon which a party intends the Commission to rely as support for or a challenge to a particular position is evidentiary in nature and should not be presented in a post-hearing brief.

56. The revision of IER recommendations during the comment period is distinguishable from CCC/CSC's inclusion of sensitivity results in its brief for the following reasons: (1) each party had the same opportunity to present their recommendations at the same time and under the same circumstances, (2) each of these submissions was accorded the same status (late-filed exhibit), (3) the same assumptions were used, (4) supporting work papers were served on each party performing a model run, and (5) each party had

fuel oil inventory carrying costs shall be continued for those costs, and similar memorandum accounts shall be created for Edison's nuclear fuel carrying costs and coal inventory carrying costs. Edison is directed to include 100% of its adopted nuclear fuel carrying costs and coal inventory carrying costs in its ECAC balancing account.

9. An Energy Reliability Index value of 0.43 shall be adopted in this proceeding.

10. A revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all groups shall be adopted in this proceeding.

11. The revenue allocation adopted in this proceeding shall be based on Edison's total adopted revenue requirement as of October 1, 1988. Details are shown in Appendices B and C to this decision.

12. Edison's off-peak energy charge included in the tariff schedules listed in Appendix D to this decision shall be returned to the 5-cent/kWh level authorized in D.87-12-066 following an inadvertent increase in that charge in D.88-05-074.

the opportunity to address the revised recommendations in their comment responses.

57. A "substitute unit," as referenced in D.88-03-079, is a "new" resource added in response to the absence of short-run QFs and not an "existing" unit returned from cold standby to fill an intermittent loss of capacity.

58. It is reasonable for those performing a "QFs Out" run to return cold standby units to service in response to a shortage in capacity.

59. To mirror actual system operations, the standby units reflected in a "QFs Out" run should be those which should actually be used to respond to intermittent capacity shortfalls, and their inclusion in this run should be limited to the actual period of time in which the capacity shortage is forecast.

60. CCC/CSC has demonstrated the reasonableness of including Etiwanda 1 and 2 and San Bernardino 1 and 2 as standby units in the "QFs Out" run for the two-month period in which a capacity shortage is forecast.

61. In forecasting Edison's system operations, it is reasonable to reflect the "probability" of forced outages in ELFIN runs and, in turn, to de-rate capacity for forced outages as well as maintenance.

62. Given the time constraints and procedures adopted for this ECAC, it is not reasonable to adopt a methodology for determining and adjustment the commit target variable.

63. The record, which includes reasonable approaches to determining commit target variables, is sufficient to permit the Commission to adopt specific commit target values in this proceeding and, with the adoption of DRA's resource mix assumptions, supports the adoption of DRA's commit target values for the forecast period.

13. Except for the off-peak energy charge referenced above, all other demand and energy charges shall be increased as a result of the rate change authorized in this decision in accordance with DRA's Class Equal Percent Change rate design.

This order is effective today.

Dated _____, at San Francisco, California.

64. For consistency between utilities with standard offer contracts, it is reasonable to apply to Edison the same approach adopted for PG&E in D.86-10-045 for determining fixed gas costs.

65. It is reasonable to reflect avoided gas costs in QF energy payments consistent with the findings of D.88-07-024.

66. Having applied the proper assumptions, forecasts, and methodologies, it is reasonable to adopt DRA's final revenue requirement and IER proposals contained in its comments to the ALJ's proposed decision.

67. In recent Edison's recent general rate case, the Commission has indicated its intent to move toward an EPMC revenue allocation for Edison "as soon as possible." (D.87-12-066, at p. 262.)

68. Recent decisions make clear the Commission's intent to consider a further phase-in of an EPMC revenue allocation for Edison in this proceeding, as well as proposals for an SAPC revenue allocation.

69. Although Edison's domestic customers will face multiple rate increases this year, the "shock" of these increases being allocated on a phased-in EPMC basis has been mitigated by the following: (1) the timing of this rate increase in terms of Edison's last general rate case, (2) the ALJ's proposed changes in Edison's ECAC scheduling, and (3) the enactment of SB 987.

70. The circumstances listed in the above finding, which also suggest the timeliness of a further movement toward EPMC in this proceeding, have produced the following results: (1) the rate change adopted in this decision will follow the general rate case by nine months and will not include the summer peak period for Edison's nondomestic service customers and some of its domestic customers, (2) the issuance of an interim order in this proceeding will result in more gradual increases in domestic rates during this year, (3) the ALJ's proposed schedule for Edison's 1989 ECAC could result in a rate change in the Edison's next ECAC at least 24

months after issuance of the general rate case, and (4) changes in domestic rates resulting from the Commission's implementation of SB 987 have resulted in providing some rate relief to Edison's Tier II residential customers.

71. The magnitude of rate increase adopted in this proceeding has the direct effect of increasing the discrepancy in actual dollar terms between the revenue responsibilities of the large power and residential classes.

72. Based on the preceding findings, it is appropriate to take a further step toward a full EPMC revenue allocation for Edison in this proceeding.

73. D.87-12-066 does not prohibit a further step toward EPMC being taken in those proceeding nor does it limit the percentage increase over the system average percentage change which can occur.

74. A reasonable basis upon which to achieve further movement toward EPMC, mitigate rate shock to the domestic customer group, and provide a balanced treatment of all of Edison's customer classes is to adopt a modified version of DRA's proposed revenue allocation.

75. It is reasonable to adopt a revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all customer groups, but with no floor on rate reductions.

76. It is reasonable to make the rate change authorized in this decision coincide, to the extent possible, with the change from the summer to winter residential baseline period.

77. In order to minimize fluctuations in the ERAM account balance, it is reasonable to leave base rate revenue requirement unchanged, except for authorized revenue changes since the interim decision, and revise base rates to reflect the new sales level.

78. It is reasonable to adjust Edison's MAAC and CLMAC rates for the new sales forecast to be consistent with the adopted approach for adjusting base rates.

79. It is reasonable to adjust Edison's Chevron Settlement Rate, Uranium Contract Termination Rate, LSFO Inventory Writedown Rate, and Distillate Inventory Writedown Rate for the new sales forecast so that all of Edison's rate elements will be determined using the most recently adopted sales forecast.

80. In D.87-12-066, the Commission did not intend to limit the exclusion of street light facilities charges from the revenue allocation process to EPMC-based revenue allocations.

81. It is equally appropriate to exclude street light facilities charges from both SAPC and EPMC revenue allocations.

82. This proceeding is not the appropriate forum for changing the treatment of interruptible credits in the revenue allocation process from that followed in D.87-12-066.

83. In D.87-12-066, the Commission intended to insulate the off-peak energy charge included in Edison's time-of-use schedules from revenue increase changes which would require other charges to be increased toward their EPMC relationships.

84. The off-peak energy charge contained in Edison's time-of-use schedules listed in Appendix D to this decision and the second block energy rate for Rate Schedules GS-2 and PA-2 should be returned to the 5-cent/kWh level approved in D.87-12-066 following their inadvertent increase in D.88-05-074.

85. Except for the off-peak energy charge and the second block energy charges referenced above, consistent with D.87-12-066 and D.88-04-027, all other charges should be changed in accordance with DRA's CEPC rate design.

Conclusions of Law

1. Edison's petition to set aside submission and reopen hearings in the forecast phase should be denied.

2. The temporary suspension of Edison's AER should be continued to November 1, 1988, but should be reinstated, effective that date, by advice letter filing.

3. The suspension of Edison's AER should occur only when and if circumstances warranting such action actually exist.

4. In this proceeding, it is reasonable to adopt DRA's recommendation to use the ELFIN production cost model to develop both Edison's revenue requirement and its IER.

5. During the comment period following issuance of the ALJ's proposed decision, DRA properly "re-ran" its ELFIN model based on the adopted forecast expenses, resource mix, and IER assumptions to produce the final revenue requirement adopted in this proceeding.

6. During the comment period following issuance of the ALJ's proposed decision, Edison, DRA, and CCC/CSC appropriately "re-ran" the ELFIN model based on the input assumptions and modeling conventions adopted in this decision to produce their final IER recommendations.

7. The revised revenue requirement and IER recommendations presented during the comment period in this proceeding should be considered late-filed exhibits and should be supported by work papers served on all parties making ELFIN runs during the comment period.

8. The agreement reached by Edison and DRA on the issues of sales forecast, Edison hydro generation, nuclear generation and expense, and the estimated ECAC and ERAM account balances should be adopted.

9. DRA's gas price forecast is reasonable and should be adopted.

10. DRA's gas generation expense forecast of $613.25 million is reasonable and should be adopted.

11. Consistency should be maintained in the forecasts of both gas and oil expenses with respect to the components which these forecasts share in common.

12. DRA's oil general expense forecast of $24.8 million is reasonable and should be adopted.

13. DRA's and Edison's agreement on the quantity of QF power and the capacity factors projected for the four large QF projects is reasonable and should be adopted.

14. DRA's forecast of PNW economy energy availability and expense is reasonable and should be adopted.

15. DRA's forecast of PSW economy energy availability and expense is reasonable and should be adopted.

16. DRA's forecast of coal generation and expense is reasonable and should be adopted.

17. DRA's and Edison's agreement on the coal inventory level and carry costs is reasonable and should be adopted.

18. DRA's forecast of a 4.4 million barrel fuel oil inventory is reasonable and should be adopted.

19. DRA's forecast of fuel oil inventory carrying costs is reasonable and should be adopted.

20. The ratemaking treatment announced in D.87-11-013 related to the establishment of a memorandum account for fuel oil inventory carrying costs should be continued for those costs and similar memorandum accounts created for nuclear fuel carrying costs and coal inventory carrying costs for later potential recovery through ECAC.

21. Edison should include 100% of its adopted nuclear fuel carrying costs and coal inventory carrying costs in ECAC.

22. DRA's recommended methodology for calculating franchise fees and uncollectible accounts expense and resale accounts allocation is reasonable and should be adopted.

23. The parties' stipulated ERI value of 0.43 is reasonable and should be adopted.

24. The "QFs Out" run performed in this proceeding to develop Edison's final IER should reflect the return to service of Etiwanda 1 and 2 and San Bernardino 1 and 2 as cold standby units for the two-month period in which a capacity shortage is forecast.

25. In determining Edison's final IER, Edison's system capacity should be de-rated for forced outages and maintenance in the manner proposed by DRA and Edison.

26. DRA's proposed commit target values for the forecast period are reasonable and should be adopted.

27. DRA's proposed approach to determining Edison's fixed gas costs is reasonable and should be adopted.

28. Avoided gas costs should be reflected in QF energy payments in a manner consistent with D.88-07-024.

29. DRA's final revenue requirement and IER proposals contained in its comments to the ALJ's proposed decision should be adopted.

30. A revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all customer groups is reasonable and should be adopted in this proceeding.

31. The rate change authorized in this decision should coincide with the change from the summer to winter residential baseline period for Edison's domestic customers in Baseline Region 15.

32. The base rate revenue requirement should remain unchanged in this proceeding except for authorized revenue changes since the interim decision (D.88-05-024).

33. Edison's MAAC, CIMAC, and base rates should be revised in this proceeding to reflect the new, adopted sales level.

34. Edison's Chevron Settlement Rate, Uranium Contract Termination Rate, LSFO Inventory Writedown Rate, and Distillate Inventory Writedown Rate should be revised in this proceeding to reflect the new, adopted sales level.

35. Street light facilities charges should be excluded from both SAPC and EPMC revenue allocations.

36. Consistent with our approach in D.87-12-066, interruptible credits should not be excluded at this time from the revenue allocation process.

37. The off-peak energy charge contained in Edison's time-of-use schedules listed in Appendix D to this decision and the second block energy rate for Rate Schedules GS-2 and PA-2 should be 5-cents/kWh.

38. Except for the off-peak energy charges and the second block energy charges contained in the schedules listed in Appendix D, all other charges should be changed as a result of the revenue increased authorized in this decision in accordance with DRA's CEPC rate design.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized and directed to file with this Commission, on or after the effective date of this order, and at least 3 days prior to their effective date, revised tariffs schedules for electric rates based on the revenue requirement adopted in Appendix C to this decision.

2. The revised tariff schedules shall become effective on or after October 1, 1988, and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. Edison's baseline and Tier II domestic rates shall reflect the decision issued today in I.88-07-009 and shall be consistent with the rates adopted in Appendix D to this decision.

4. The temporary suspension of Edison's Annual Energy Rate (AER) adopted in D.88-05-024 shall be continued to November 1, 1988. The AER shall be reinstated at the 10% level by advice letter filing effective November 1, 1988. AER revenues will be

$217 million, offset by a $217 million reduction to Energy Cost Adjustment Clause (ECAC) revenues.

5. Effective October 1, 1988, Edison's base rate revenue requirement shall remain unchanged except for authorized revenue changes since the interim decision, but Edison's base rates shall be revised to reflect the sales level adopted in this proceeding. Edison's Major Additions Adjustment Clause (MAAC) rates, Conservation and Load Management Adjustment Clause rates, and the amortization rates set forth in Appendix C shall similarly be revised to reflect the new sales level. (See, Appendix C to this decision.)

6. The ratemaking treatment announced in D.87-11-013 involving the establishment of a memorandum account for Edison's fuel oil inventory carrying costs shall be continued for those costs, and similar memorandum accounts shall be created for Edison's nuclear fuel carrying costs and coal inventory carrying costs for later potential recovery through ECAC. Edison is directed to include 100% of its adopted nuclear fuel carrying costs and coal inventory carrying costs in its ECAC balancing account.

7. An Energy Reliability Index value of 0.43 and an annual Incremental Energy Rate (IER) of 9,763 Btu/kWh shall be adopted in this proceeding. DRA's proposed time-differentiated IERs shall also be adopted.

8. A revenue allocation based on a weighted average of 1/3 EPMC and 2/3 SAPC with a 2.5% cap over the system average percentage change for all groups shall be adopted in this proceeding.

9. The revenue allocation adopted in this proceeding shall be based on Edison's total adopted revenue requirement as of October 1, 1988. Details are shown in Appendices B and C to this decision.

10. Effective October 1, 1988, Edison's off-peak energy charge included in the tariff schedules listed in Appendix D to

this decision and the second block energy rate for Rate Schedules GS-2 and PA-2 shall be returned to the 5-cent/kWh level authorized in D.87-12-066 following an inadvertent increase in that charge in D.88-05-074.

11. Effective October 1, 1988, except for the off-peak energy charge and the second block energy charges referenced above, all other demand and energy charges shall be increased as a result of the rate change authorized in this decision in accordance with DRA's Class Equal Percent Change rate design.

12. Edison's petition to set aside submission and reopen hearings in the forecast phase of this proceeding is denied.

This order is effective today.

Dated SEP 14 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Adopted Base Rate Revenue Requirement - California Jurisdiction

Line	Annual Revenues ($ million)	Effective Date	Item
	(a)	(b)	(c)
1	$ 3,239.665	1/1/88	Authorized Level of Base Rate Revenues
	Changes to base rate revenue requirement since 1/1/88:		
2	19.967	1/20/88	Palo Verde 3 COD
3	20.191	2/1/88	Palo Verde 1 phase-in
4	11.139	3/18/88	Palo Verde 3 base rates
5	20.191	10/1/88	Palo Verde 2 phase-in
6	7.190	"	Tax Reform Act true-up
7	+ (4.071)	"	Palo Verde base rate true-up
8	$ 3,314.271	10/1/88	Total base rate revenue requirement (including facilities charges)

Notes:

Line 1. A.86-12-047, D.87-12-066.
Line 2. A.L. 777-E, Res. E-3077; noninvestment expenses and decommissioning.
Line 3. I.85-05-001, D.86-10-023, A.L. 774-E.
Line 4. A.87-08-054, D.88-03-022.
Line 5. A.L. 795-E, approval pending; margin change effective 9/19/88.
Line 6. A.L. 783-E, approval pending.
Line 7. Advice filing pending.

(END APPENDIX B)

SOUTHERN CALIFORNIA EDISON COMPANY
Revenue Changes Adopted for Revenue Allocation and Rate Design - California Jurisdiction
ECAC Forecast Period June 1, 1988-May 31, 1989

LINE	REVENUE ELEMENT	PRESENT RATE REVENUE 1/ 2/ 3/ ($ million)	OCTOBER 1 REVENUE CHANGE ($ million)	OCTOBER 1 ADOPTED REVENUE ($ million)	NOVEMBER 1 REVENUE CHANGE ($ million)	NOVEMBER 1 ADOPTED REVENUE ($ million)	NOVEMBER 1 AVERAGE RATE (cents/kwh)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Base rates	$3,318.781	($4.510)	$3,314.271 4/	$0.000	$3,314.271	5.075
2	Major Additions Adjustment Clause (MAAC)						
3	SONGS 2 and 3 post-COD	52.903	(0.304) 5/	52.599	0.000	52.599	0.081
4	Balsam Meadow	36.576	(0.747) 5/	35.829	0.000	35.829	0.055
5	Devers-Valley-Serrano	19.594	(0.152) 5/	19.442	0.000	19.442	0.030
6	SONGS pre-COD balancing account	8.491	(0.251) 5/	8.240	0.000	8.240	0.013
7	TOTAL MAAC	117.564	(1.454) 5/	116.110	0.000	116.110	0.178
8	Conservation Load Management Adjustment Clause (CLMAC)	(16.981)	0.211 5/	(16.770)	0.000	(16.770)	(0.026)
9	Energy Cost Adjustment Clause (ECAC)						
10	Fuel and purchased power	2,021.767	181.966	2,203.733	(217.189)	1,986.544	3.042
11	Balancing account	(137.808)	47.464	(90.344)	0.000	(90.344)	(0.138)
12	LSFO writedown	54.862	(2.470) 5/	52.392	0.000	52.392	0.080
13	Distillate writedown	4.572	0.120 5/	4.692	0.000	4.692	0.007
14	Chevron settlement	204.427	(2.541) 5/	201.886	0.000	201.886	0.309
15	Uranium contract termination	77.721	(0.966) 5/	76.755	0.000	76.755	0.118
16	TOTAL ECAC	2,225.541	223.573	2,449.114	(217.189)	2,231.925	3.417
17	Annual Energy Rate (AER)	0.000	0.000	0.000	217.189	217.189	0.333
18	Electric Revenue Adjustment Billing Factor (ERABF)	(9.143)	(41.940)	(51.083)	0.000	(51.083)	(0.078)
19	SUBTOTAL	5,635.762	175.879	5,811.642 6/	0.000	5,811.642	8.899
20	Other Operating Revenue	57.547	0.000	57.547	0.000	57.547	
21	CPUC fees	7.841	0.000	7.841	0.000	7.841	
22	TOTAL	$5,701.150	$175.879	$5,877.029	$0.000	$5,877.029	

1/ Based on adopted ECAC sales of 65,310.25 GWH, after adjustment for employee discounts and exclusion of fringe and Sequoia sales (65,340 GWH unadjusted).
2/ Present rates using current tariffs, which were made effective 6/1/88.
3/ Present rate revenues reflect test year 1988 optional TOU meter charges, and differ slightly from interim Decision 88-05-074. Recovery of revenue for optional TOU meters will be reflected in attrition per Decision 87-12-066.
4/ Revenues from Appendix B, reflects revenue changes due to revised sales forecast and other authorized base revenue changes effective 10/1/88.
5/ Revenue change due solely to revised sales forecast.
6/ Revenue used for revenue allocation and rate design.

(END APPENDIX C)

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Rate Appendix Highlights
Effective October 1, 1988

Domestic

[Expect to reflect implementation of SB987 baseline legislation resulting from I. 88-07-009 in final decision. Winter baseline allowances to be changed as directed in Decision 87-12-066.]

Small/Medium Power

GS-2: Second block energy rate set at 5 cents/kWh

TOU-GS: Off peak energy rate set at 5 cents/kWh

Large Power

TOU-8: Off peak energy rate set at 5 cents/kWh

Agriculture

PA-2: Second block energy rate set at 5 cents/kWh

TOU-PA, TOU-PA-3, TOU-PA-4, TOU-PA-5: Off peak energy rates set at 5 cents/kWh

Note: customer charges and demand charges to be increased by percent increase to rate group. Rates above exclude CPUC reimbursement fee.

(END APPENDIX D)

LIST OF APPEARANCES

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

Interested Parties: Lindsay, Hart, Neil & Weigler, by Michael Alcantar and Paul J. Kaufman, Attorneys at Law, for Cogenerators of Southern California; Barbara Barkovich, for CLECA, California Steel Producers Group; Jackson, Tufts, Cole & Black, by Allan Thompson and William Booth, Attorneys at Law, for CLECA; Morrison & Foerster, by Jerry R. Bloom, Attorney at Law, for California Cogeneration Council; R. H. Berby, for CLECA; Matthew Brady and Dian M. Grueneich, Attorneys at Law, for California Department of General Services; Deborah Bosch, for Energy Modeling Forum; David Branchcomb, for Henwood & Associates, Inc.; McCracken, Byers & Martin, by David J. Byers, Attorney at Law, and Reed V. Schmidt, for California Street Light Association; Bryan Cope, for Sierra Energy and Risk Assessment, Inc.; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Sam DeFrawi, for Naval Facilities Engineering Command; Karen Edson, for KKE & Associates; Mike Florio, Attorney at Law, for TURN; Steven Geringer, Attorney at Law, for California Farm Bureau Federation; Cynthia Hall, Attorney at Law, for Department of the Navy; Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobile Home Association; Jan Hamrin, for Independent Energy Producers; William Marcus, for JBS Energy, Inc.; Graham & James, by Robert C. Lopardo and Martin A. Mattes, Attorneys at Law, for California Hotel and Motel Association; A. Kirk McKenzie and Antonia Radillo, Attorneys at Law, for California Energy Commission; John D. Quinley, for Cogeneration Service Bureau; T. D. Clarke, R. B. Keeler, Attorneys at Law, and R. M. Rawlings, for Southern California Gas Company; Donald G. Salow, for Association of California Water Agencies; Donald W. Schoenbeck, for Cogenerators of Southern California; Gary Simon and Steve Harris, for El Paso Natural Gas; Clark Smith, for Transwestern Pipeline Company; James D. Squeri, for California Building Industry Association; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Christopher T. Ellison, Attorneys at Law, for Industrial Users; Michael R. Weinstein,

Attorney at Law, for San Diego Gas & Electric Company; Harry K. Winters, for University of California; Bill Dixon, Carl Wood, and John Chabot, for Utility Workers Union of America; Lawrence E. DeSimone, for Energy Management Associates, Inc.; Norman Furuta, Attorney at Law, for Federal Executive Agencies; and Harvey Mark Eder, for Public Solar Power Coalition and himself; and Graham & James, by Norman Pederson, Attorney at Law, Kathryn L. Stein, and Robert Weisenmiller, for themselves.

Division of Ratepayer Advocates: Carol Matchett and Robert C. Cagen, Attorneys at Law, Bill Y. Lee, and Meg Gottstein.

Commission Advisory and Compliance Division: Frank Crua.

(END OF APPENDIX A)

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Adopted Base Rate Revenue Requirement - California Jurisdiction

Line	Annual Revenues ($ million)	Effective Date	Item
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(END APPENDIX B)

APPENDIX C

SOUTHERN CALIFORNIA EDISON COMPANY
Revenue Changes Adopted for Revenue Allocation and Rate Design - California Jurisdiction
ECAC Forecast Period July 1, 1988-June 30, 1989

LINE	REVENUE ELEMENT	PRESENT RATE REVENUE 1/ 2/ 3/ ($ million)	ADOPTED REVENUE ($ million)	REVENUE CHANGE ($ million)	AVERAGE RATE (cents/kwh)
	(a)	(b)	(c)	(d)	(e)
1	Base rates	$3,319.183	$3,314.271 /4	($4.912)	5.075
2	Major Additions Adjustment Clause (MAAC)	117.558	116.110	(1.448) 5/	0.178
3	Conservation Load Management Adjustment Clause (CLMAC)	(16.981)	(16.770)	0.211 5/	(0.026)
4	Energy Cost Adjustment Clause (ECAC)	2,225.541	2,234.547	9.006	3.421
5	Annual Energy Rate (AER)	0.000	216.830	216.830	0.332
6	Electric Revenue Adjustment Billing Factor (ERABF)	(9.143)	(51.083)	(41.940)	(0.078)
7	Subtotal	5,636.158	5,813.905	177.747	8.902
8	Other Operating Revenue	57.547	57.547	0.000	
9	CPUC fees	7.841	7.841	0.000	
10	Total	$5,701.546	$5,879.292	$177.747	

1/ Based on adopted ECAC sales of 65,310.25 GWH, after adjustment for employee discounts (65,338 GWH unadjusted).

2/ Present rates using current tariffs, which were made effective 6/1/88.

3/ Present rate revenues reflect test year 1988 optional TOU meter charges, and differ slightly from interim Decision 88-05-074. Recovery of additional revenue for optional TOU meters will be reflected in attrition per Decision 87-12-066.

4/ Revenues from Appendix B, not equal to present rate revenues due to revised sales forecast and changes to authorized revenues since 6/1/88.

5/ Revenue change due solely to revised sales forecast.

(END APPENDIX C)

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Rate Appendix Highlights
Effective October 1, 1988

Domestic

[Expect to reflect implementation of SB987 baseline legislation resulting from I. 88-07-009 in final decision. Winter baseline allowances to be changed as directed in Decision 87-12-066.]

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GS-2: Second block energy rate set at 5 cents/kWh

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