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ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Investigation on the Commission's own motion to consider Cost - Effective Programs to reduce use of Oil and Natural Gas for Southern California Edison Company's electric generation	OII 82-04-02 (Filed April 28, 1982)

(See Appendix A for appearances.)

INTERIM OPINION

I. SUMMARY

Today's decision revises the procedures by which Southern California Edison Company's (Edison's) fuel-related expenses are recorded and passed into rates. These revisions are designed to provide Edison clear and more effective incentives to manage its fuel costs efficiently. We intend to apply similar principles in making revisions to the fuel cost recovery procedures for California's other electric utilities.

Under today's revisions, the Commission will continue to adopt an annual forecast of all fuel-related expenses. Ten percent of the forecast amount will be placed in the Annual Energy Rate (AER) for recovery in rates. The remaining 90% will be placed in the Energy Cost Adjustment Clause (ECAC) balancing account, and used to calculate a billing factor which would recover the projected account balance over the year. If actual fuel-related expenses vary, the utility will be able to recover changes in the ECAC share through adjustments in the billing factor. However, because each year's AER amount will not be changed to reflect expense changes, this AER/ECAC split means that utility shareholders will bear 10% of any unforecast changes in fuel-related expenses.

The new allocation changes the present AER/ECAC procedure in two major ways. First, it provides uniform rate treatment for all fuel-related expenses, thus eliminating perverse incentives for utility management inherent in the current procedure. This move to uniformity reduces from 100% to 10% the portion in AER of four fuel expenses related to the management of fuel oil inventory: carrying costs of fuel oil in inventory, underlift charges, facilities charges, and gains or losses from sale of oil inventory. Second, the new procedure increases the AER portion of all remaining fuel-related costs from 2% to 10%, while limiting the total possible variation in earnings attributable to fuel cost changes.

Under the present AER/ECAC split, there is considerable risk to Edison's shareholders that their earnings will be affected by swings in expenses of items contained in the AER. By reducing the company's share of risks related to fuel oil inventory from 100% to 10%, we are reducing a major risk to shareholders.

We also limit a second risk to Edison's shareholders. In the system replaced today, there has been no limit to potential gains or losses from changes in the 2% of other fuel costs contained in the AER. We will adopt a cap on total earnings fluctuations which can be caused by unforecast changes in fuel expenses. This cap will be 160 basis points on pretax return on common equity, which represents slightly more than $32 million in 1983.

This realignment of the risks related to fuel expenses should not significantly affect Edison's cost of capital. Shareholders and ratepayers will have some of their fuel-related risks increased, and some decreased. We believe the result is an appropriate balance of risks and opportunities.

The ratepayers will also benefit directly from the newly-adopted system. First, their share of the risk of most fuel-

related cost changes is reduced from 98% to 90%. Second, the move to treat all fuel costs consistently eliminates the present system's incentive to the utility to manage AER-recovered expenses differently than ECAC-recovered expenses. Under the new AER/ECAC mechanism, every action Edison takes to reduce its own expenses will also reduce the expenses charged to the ratepayers.

II. INTRODUCTION

On April 28, 1982, the Commission issued Order Instituting Investigation (OII) 82-04-02, an investigation on its own motion into appropriate incentives for efficient management of fuel costs by Edison. While Edison was the only named respondent, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCal) were directed to participate and comment on policy issues. These energy utilities participated actively in recognition that the findings and conclusions of OII 82-04-02 might be applied to them.

OII 82-04-02 identifies as its central issue the allocation of risk between shareholders and ratepayers in conjunction with the minimization of total energy costs. The investigation focused on two specific areas of interest: (1) what modifications in ECAC procedures, if any, would enhance the incentives for utilities to minimize their fuel costs, and (2) what incentives can be adopted through ECAC and AER to encourage the development and use of alternative resources to reduce the utilities' reliance on oil and gas for electric generation.

The Commission set out six specific policy issues for analysis as a means of focusing the testimony:

a. Whether the current 2% of estimated fuel cost included in the Annual Energy Rate (AER) should be maintained, increased, or eliminated.

b. Whether gains or losses on the sale of fuel oil and underlift and facilities charges should continue to be estimated in advance and included in the AER.

c. Whether the carrying cost of oil in inventory should continue to be included in the AER.

d. How and to what extent carrying costs of excess oil in inventory should be recovered.

e. Whether the ECAC balancing account ratemaking procedure should be gradually terminated in phases, or terminated completely, or whether any particular fuel component now included in ECAC should be excluded.

f. Whether it is feasible and/or desirable to change the allocation of risks and rewards between ratepayers and shareholders created by the ECAC to minimize fuel costs.

Fifteen days of hearing were held between August 16 and September 28, 1982. Evidence was presented by Edison, PG&E, SDG&E, Sierra Pacific Power Company (Sierra Pacific), Toward Utility Rate Normalization (TURN), and the Commission Staff (Staff). The matter was submitted on September 28, subject to receipt of concurrent briefs on October 29, 1982. Briefs were filed by Edison, PG&E, SDG&E, SoCal, TURN, City of San Diego, California Department of Consumer Affairs, and Staff.

III. SUMMARY OF PROPOSALS

A. Edison

Edison proposes that the current AER/ECAC procedures be maintained without change. All facets of the current procedures, including the 98% ECAC/2% AER split, the 100% recovery of underlifts, carrying costs and gains or losses on the sale of fuel oil, and the temporary continuation of balancing account treatment for facilities charges, should be retained. Edison recommends that a floating

inventory procedure be adopted to account for oil in inventory in excess of adopted levels and suggests adoption, in a future Edison ECAC proceeding, of a mechanism for ratepayers and shareholders to share costs occasioned by deviations of fuel oil inventory levels from adopted levels. Edison also feels it is essential that the Commission establish criteria for determining the appropriate base level of fuel oil to be adopted.

Edison has indicated that it would prefer 100% balancing account treatment for all fuel-related expenses, but does not advocate such treatment at this time. Edison contends that investors are still considering the impact of the current procedure which has been in effect for less than two years for Edison, and that any change in ECAC procedures would have an unsettling influence upon them. Sierra Pacific's position is in substantial concurrence with Edison's.

B. PG&E

PG&E's primary recommendation calls for 100% recovery of all fuel-related expenses through ECAC, and elimination of the AER. PG&E contends that the annual reasonableness review of energy expenses conducted by the Commission is a sufficient incentive to the utility to encourage cost minimization. PG&E further argues that AER-type recovery is not fair to either the utility or the ratepayers, since chance events can have a large impact on the level of expenses estimated in advance.

In the event the Commission retains the AER, PG&E has two proposals for the treatment of oil in inventory. The first mechanism, designed for PG&E by its consultant, Energy Management Associates, Inc. (EMA), calls for continued estimation of an annual level of oil in inventory, for which carrying costs could be included

in the AER.[1] Subsequent additional costs of excess oil in inventory during any given year would be allocated so that 30% of the extra costs would be borne by PG&E's shareholders while the remaining 70% would be recovered from the ratepayers through ECAC. This mechanism is referred to as a Floating Inventory Mechanism. PG&E, however, disagrees with EMA's recommendations and suggests, alternatively, that 100% of any carrying costs in excess of those adopted annually and recovered in base rates be afforded balancing account treatment.

Through rebuttal testimony, PG&E urges retention of the current annual reasonableness review, while recommending a plan to increase its effectiveness without causing further delay in rate relief. PG&E proposes review of reasonableness issues in hearings to be held after an initial round of hearings in which offset and balancing rates are set and implemented. PG&E argues that this bifurcation would allow sufficient time to examine reasonableness issues in detail without delaying the implementation of new rates. In addition, PG&E proposes a requirement that the utility present in the reasonableness hearings a detailed analysis of its then current operating forecast for the coming year which would serve as a benchmark in the record for consideration in the following year's reasonableness review. Further, PG&E proposes a timetable or regulatory lag plan for the reasonableness review, which calls for hearing and decision within 180 days of the close of the record period.

C. SDG&E

SDG&E proposes recovery of 100% of all energy-related expenses through ECAC. If the Commission rejects this

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[1] The EMA mechanism assumes continuation of the existing ECAC/AER procedures and percentages of fuel cost recovery.

recommendation, SDG&E suggests expansion of ECAC to include all energy expenses except facilities charges and certain fuel oil inventory costs. SDG&E recommends elimination of most of the AER. Underlifts, oil sale losses and gains, and certain inventory expenses would be placed in the balancing account. The AER would retain only facilities charges and the carrying charges for the adopted level of fuel oil in inventory.

SDG&E proposes a "deadband" mechanism for handling variations in fuel oil in inventory:

> "The annual expected level of fuel oil in inventory is adopted and the carrying costs are included in base rates; a 'deadband' encompassing some 70-80% of the expected variations in that inventory level is set. To the extent that inventory levels vary within that deadband, the resulting carrying costs are recovered in full through the balancing account. If expenses vary outside of the adopted deadband, the utility would not recover those carrying costs without making a specific showing justifying the reasonableness of those expenses in the reasonableness review. Similarly, if the expenses are lower than the adopted level by more than the deadband allowance, the utility would have to justify why a refund to customers would not be appropriate."

D. SoCal Gas

SoCal, in substantial agreement with SDG&E and the other utilities, advocates continued recovery through ECAC of expenses related to the purchase and use of natural gas for electric generation. SoCal concludes that the ECAC recovery mechanism promotes the use of natural gas, which it argues is a better and more efficient fuel.

E. TURN

TURN advocates major reform of the current cost recovery mechanisms used by the Commission in setting rates for the major electric utilities.

TURN's underlying premise is that a combination of ineffective review of utility energy operations and a multiplicity of balancing accounts which recover in rates the vast majority of energy expenses has resulted in the elimination of incentives for the utilities to minimize costs and aggressively seek alternatives to fossil fuels. TURN believes that the current reasonableness review is too limited in scope and too dependent upon information provided by the utilities to provide an effective independent check upon energy operations.

TURN proposes to replace the allegedly cumbersome ECAC/AER format with a single, prospective, and all-encompassing annual rate case for each major utility. The proceeding would cover all aspects of the utility's operations, estimate expenses in advance for a forward-looking test year, and establish rates. Retrospective reasonableness review would be eliminated. The City of San Diego joins in this recommendation.

At the conclusion of the test year, a "true-up" proceeding would take place, with two main functions. First, the true-up proceeding would make a "pro forma" adjustment to energy costs to normalize the effect of certain chance events which had affected estimated energy costs.

The second major adjustment contemplated in the true-up proceeding requires adoption in the annual rate case of a deadband or range of expense variations for energy expenses.[2] Once the deadband is established, the utility would absorb in full any expense variations within the deadband. Furthermore, there would be no reasonableness review if expenses varied within the deadband.

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[2] TURN proposed no specific level of variation or dollar amount for the deadband.

If, however, expenses varied to a point beyond the deadband, the true-up proceeding would examine the reason for the variation. If the expense variations were due to uncontrollable and unpredictable factors, the variation would be eligible for balancing account treatment.

TURN also proposed an alternative method for recovery of oil inventory expenses. TURN suggests that oil in inventory up to the level normally required for operation of the generation plants receive treatment as a rate base item, forecast in advance of the test year and included in rates through calculation of carrying charges using the authorized rate of return. Oil held in excess of the adopted operational level would be recoverable in rates, usually via the true-up proceeding; but the carrying costs would be calculated using the short-term interest rate applicable at the time, such as the present ECAC balancing account interest rate now used. Any adjustment for oil inventory in excess of the adopted operational limit would only apply for changes in oil inventory caused by factors other than the uncontrollable expense variations contained in the pro forma adjustment.

F. Commission Staff

The Commission staff analyzed the present ECAC/AER procedures, and the degree to which utility management can control fuel-related costs. Staff then presented three alternative proposals for changing ECAC/AER to reallocate risks between ratepayers and shareholders.

1. Analysis of Factors under Management Control.

Staff's analysis emphasizes that management's ability to control fuel-related costs varies greatly overtime. In a single year, Edison is largely dependent on the effects of market and weather forces on the company's forecast supply and demand. To some extent, improved forecasting can reduce the impacts of such

fluctuations. Even in a single year, a utility can affect fuel-related expenses by assuring the reliability of its facilities, and by taking advantage of spot market and purchased power opportunities.

In the short term, a utility can improve plant reliability through operations and maintenance policies, can diversify supply sources for needed fuels, and can develop and institute cost-effective conservation and load management programs. These activities begin to reduce the utility's vulnerability to fluctuations in what the utilities have called in this proceeding "uncontrollable" factors.

Over the long term, management has considerable "control" over fuel-related costs. Most importantly, construction of generation, transmission and distribution facilities can reduce the system's dependence on less secure sources, and so minimize vulnerability to price and supply fluctuations. For example, Edison's resource plan is directed toward diversifying energy sources and reducing dependence on oil and gas.

In the long term, random fluctuations in "uncontrollable" hydroelectric and purchased power sources will also average out. The company can plan its system to make the most cost-effective use of such sources, including provisions for alternative generation in low-hydro years.

Staff is concerned that any revisions in ECAC/AER recognize that degrees of "controllability" increase over time. Staff proposes higher utility shares in the risks of variations in fuel price and supply, to hasten management efforts to assert immediate-, short- and longer-run control over fuel-related expenses. Staff also proposes a "cap" on fuel-related fluctuations in utility return, to protect the company from financial hardship, especially in the early years when fewer risk-controlling decisions have been implemented.

2. Proposed AER/ECAC Changes.

All three of Staff's main proposals for revising ECAC call for an increase in the percentage of energy-related expenses subject to AER treatment. The proposals are distinguished primarily by the manner in which the AER-ECAC percentages are calculated.

a. The Utilities Division advocates a mechanism labeled Stabilized Percentage Equivalency Risk Opportunity Sharing (SPEROS) which would operate to allocate all fuel costs between ECAC and AER rates so that a variation in the forecasted energy expense will produce the same percentage change in utility shareholder earnings as the percentage change in customer rates. Using current data for Edison, this mechanism produces a 16% AER/84% ECAC distribution of costs.

b. The Revenue Requirements Division recommends allocating the fuel costs between ECAC and AER so that the utility would absorb a percentage of energy costs which makes the risk of earnings fluctuation due to fuel-related expenses comparable to the earnings risk the utility normally experiences for other costs, such as the expense items included in the biennial general rate cases. For Edison, this method produces a 13% AER - 87% ECAC distribution of costs.

c. The Policy and Planning Division proposes a 20% AER - 80% ECAC distribution of fuel-related costs, based upon an analysis of the increase in risk that Edison can sustain without causing a significant increase in Edison's cost of capital.

All three proposals incorporate a "cap" which would limit the possible annual earnings variation from increased allocation of energy costs to the AER. The proposals for the size of the cap vary, and are based upon differing measures of earnings. Utilities Division would limit the variation to 5% of the return on common equity. The Revenue Requirements Division would limit the variations in return on rate base to 35 basis points. Finally, the Policy and Planning Division proposes to limit fluctuations in pretax return on common equity to 300 basis points. The after-tax financial risk to Edison in years of extreme fuel expense variation would amount to $25.9 million, $26.9 million, and $45.8 million respectively.[3]

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[3] The dollar estimates are based upon the rate base set forth in the Staff report at p. 50, as well as on information provided in Exh. 34, A.61138, which includes the staff's recommended rate of return on equity (17.25%).

In addition to the proposals to revise the AER/ECAC split, the Staff has presented a series of minor adjustments to current ECAC procedures which could be adopted as a more limited reform of ECAC. These proposed adjustments include two which can be implemented simultaneously with the revised AER/ECAC percentages.

1. Institute uniform AER/ECAC cost allocation for all fuel-related expenses, including inventory carrying costs, underlifts, oil sale gains or losses and other such items which are now recovered entirely through the AER.

2. For purposes of calculating carrying costs on fuel oil inventory recoverable through ECAC, the Commission should use the most recent twelve-month-ended realized rate of return, rather than the present system which makes the carrying cost calculation based upon the authorized rate of return.

In addition, Staff outlined four measures designed to be implemented independently of any change in the AER/ECAC split:

1. Limit balancing account treatment for fuel oil and natural gas to:

   a. Volume fluctuations using the original price estimates adopted at the beginning of the twelve-month ECAC period.

   b. Price fluctuations only for volumes of oil or gas included in the original estimate of fuel expense at the beginning of the twelve-month ECAC period.

2. Study the effectiveness of implementing power plant efficiency standards for all generating plants to formulate incentives to minimize oil and gas usage.

3. Allow interest on the ECAC balancing account only on a net after tax balance, on a monthly basis.

4. Allow recovery of revenues for franchise fees and uncollectible expenses for ECAC on an estimated basis.

Staff suggests that oil in excess of the adopted annual inventory level be accorded treatment consistent with all other fuel-related expenses. Under Staff's proposal, if the Commission were to adopt a 16% AER - 84% ECAC, 16% of the inventory cost for excess oil would be borne by the shareholders, and 84% of the costs would be recovered through the ECAC balancing account.

The Staff also outlines more complete revisions of fuel cost recovery procedures which are worthy of future discussion but which it admits are insufficiently detailed to be implemented at this time. First, future energy cost recovery proceedings might set specific limits on the amount of oil and gas fuel which can be recovered in rates. These limits could be reduced each year to encourage a steady reduction in the use of such fossil fuels. Second, major energy utility rate proceedings could be restructured so that energy costs could be considered in conjunction with other fuel-related expenses, such as conservation, load management, maintenance, facility planning, and rate design.

IV. POSITION OF THE PARTIES

A. The Utilities' Position

The utilities are in essential agreement that 100% recovery of all fuel-related expenses through ECAC with an annual reasonableness review constitutes the most effective mechanism for satisfying the legitimate interests of both shareholders and ratepayers. This proposal is advanced because of the alleged unpredictability, volatility and uncontrollability of the utilities' energy mix and costs. The utilities also generally agree in their criticism of the TURN and Staff proposals. Therefore, their positions will be presented as one.

The utilities contend that the Staff and TURN proposals are founded upon the false premise that increased financial exposure to fuel cost uncertainty will enhance the utility's incentive and ability to minimize fuel costs. The utilities find no factual support for a finding that an increase in the utility's direct financial stake in its fuels management decisions will induce the desired action of minimizing costs and reducing reliance on oil and gas.

The utilities argue that the underlying assumption of the TURN and Staff proposals is unfounded because:

1. Utilities already have the greatest financial, corporate, and regulatory incentives to minimize all costs, including fuel costs, consistent with their obligation to serve;

2. The supposed incentive offered is at best transitory, potentially illusory, and may simply produce gamesmanship, as opposed to additional efforts to reduce fuel costs;

3. Even if the utility's incentive to further reduce costs could be enhanced, given the uncontrollable nature of fuel costs, there is little, if any, further action the utility could take to lower fuel costs;

4. The earnings fluctuations and financial risks to which the Staff and TURN recommendations would expose the utility would impair the utility's financial health, increase its cost of capital, reduce its access to capital, and therefore jeopardize its long-term ability to secure alternative energy resources.

The utilities believe that the annual reasonableness review provides the appropriate signal to minimize energy costs. Since all energy costs are subject to review of their reasonableness and prudency, a sufficient incentive to minimize costs exists.

Absent compelling circumstances, the reasonable and prudent action is to minimize energy costs. Thus, the annual reasonableness review provides the appropriate signal to minimize energy costs, and allows the utility some opportunity to explain circumstances, such as environmental considerations, which forced it to deviate from that goal. No such opportunity for explanation is provided under a formula incentive such as the AER.

Even if additional incentives for cost minimization were warranted, the Staff and TURN proposals fail, in the utilities' opinion, to induce the desired result. The utilities posit that the proposed incentives would only work if management had sufficient control over energy costs to be able to respond to the incentive. The utilities claim that all the evidence demonstrates that the utility has no realistic ability to respond to the incentive by further reducing costs because energy costs are dominated by events outside the control of utility management. For Edison, the annual swing in uncontrollable short-term energy costs may be as high as $500 million above or below normal year levels considering potential fluctuations in demand, hydro, purchased power, and natural gas availability. In PG&E's case, the annual swing in uncontrollable short-term costs could be as high as $1 billion. Therefore, they conclude that the incentive provided is illusory.

The utilities further maintain that this illusory incentive might even backfire. Since energy costs are substantially uncontrollable, the utilities would reduce their exposure to variation between the AER forecast and actual energy expense by improving their forecasting capabilities.

The utilities note that accurate forecasting is not the same as cost minimization. Accuracy in forecasting simply indicates that the utility is a good forecaster. It reveals nothing about how well the utility manages fuels. The utilities argue that each proposal to increase the AER will therefore create an incentive to seek stable, easily forecast energy sources, regardless of their relative cost.

Consequently, the utility could have an incentive to favor predictable energy sources with steady availability, such as firm purchased power contracts, over sources more difficult to predict, such as economy purchase arrangements, regardless of cost comparisons. The utilities argue that this incentive against uncertain energy sources will impede the desired development of alternative energy sources. New technologies, such as solar and wind, have not yet proven commercially feasible and have unknown reliability. Such new sources could have volatile, uncontrollable availability. Therefore, the utilities conclude that a company seeking to maximize its profits would have a strong incentive to avoid these new and unpredictable resources.

The utilities further assert that Staff's alleged incentive would, in practicality, be so diluted as to be of minimal value. The utilities contend that under each Staff proposal, any revenue benefit for reducing fuel costs will be transitory. As the utility improves its performance, the resulting lower costs will be reflected in all future years' forecasts, resulting in a lower AER allowance. Therefore, the utilities claim that any incentive provided by increasing the AER percentage would be diluted as the utility could reap its rewards only in the initial year.

Finally, the utilities argue that the Staff and TURN proposals, if implemented, would increase the utilities' potential earnings fluctuations and so result in an increased cost of capital. The utilities claim that the Staff and TURN proposals are not improved by their proposed earnings fluctuation caps. If the Commission properly allows this increase in earnings fluctuations to be reflected in the utility's authorized rate of return, customers' rates will be increased. If the Commission does not reflect the increased cost of capital in the authorized rate of return, or delays inclusion in the authorized rate of return, the utility's financial position will deteriorate and its ability to attract needed capital will be impaired.

The utilities argue that increased volatility in earnings will cause investors, particularly bondholders, to question the utility's ability to satisfy its fixed obligations. In turn, the wariness with which investors view earnings volatility will cause the utility's cost of capital to increase.

B. TURN's Position

TURN argues that existing procedures transfer excessive risk from the utilities and their shareholders to the ratepayers. Furthermore, TURN has witnessed with alarm the proliferation of special balancing accounts and adjustment clauses in recent years. In TURN's view, this development has led to unacceptable regulatory fragmentation. Every application deals with partially overlapping issues and expense items, yet no one case provides a single, comprehensive overview of the entire utility. As a result no member of the Commission staff can adequately cover a utility.

In TURN's view, there is little incentive for the utilities to pursue least cost fuel strategies under current procedures. The essential feature of TURN's proposal is replacement of the ECAC/AER format with a single, prospective ratemaking proceeding in which the utility would face significant risks and opportunities in its management of fuel costs. The State Department of Consumer Affairs shares this position.

TURN recommends accomplishment of this goal by adoption of an annual forecast of fuel-related expenses, as in a general rate case, and a requirement that the utilities operate within that budget, subject to certain limitations. TURN contends that adoption of its proposal would provide the following immediate benefits:

1. Electric rates would generally be stable and predictable for an entire year.

2. Retrospective reasonableness review would be eliminated. Rates would be established once each year to cover estimated fuel costs. These estimates would not be generated in the often perfunctory manner that typifies current ECAC proceedings, but rather would result from the same searching examination that occurs in the general rate case forum. The "burden of proof" problems inherent in the retrospective reviews would be largely eliminated.

3. The artificial distinction between fuel-related costs dealt with in the general rate case, e.g., conservation, load management, operating efficiency expenses, etc., and those now covered by ECAC would be eliminated.

4. The utility would have a significant incentive to minimize fuel costs, but would not be exposed, beyond reasonable limits, to unpredictable or uncontrollable deviations from forecasted energy costs.

5. Electric utility customers would enjoy a far greater degree of assurance that the energy-related components of their monthly bills included only fair and reasonable costs. Changes in rates implemented outside of the regular, annual rate adjustment would be directly related to understandable factors such as major variations in rainfall.

TURN illustrates operation of its proposal by use of a hypothetical.

> Following appropriate hearings, a 12-month fuel cost estimate for a test year beginning January 1, 1983 is adopted by the Commission for utility "X". This estimate is based on normal rainfall and projects a revenue requirement of $2.5 billion for energy costs. Base rates sized to satisfy this revenue requirement are set by the Commission. At the close of the test year an annual "true-up" filing would be required. The utility would present its actual fuel costs for the past year (assume $2.7 billion). The utility would also present "adjusted" or "normalized" costs reflecting those expenses that would have been incurred had hydro production matched the forecasted level (a pro forma hydro adjustment). Any factors other than hydro, such as natural gas prices or purchased power quantities, that the Commission considers to be categorically uncontrollable and unpredictable would, like hydro, be an "above-the-line" item and therefore be reflected in this pro forma adjustment.
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> For utility "X" the normalized rate year costs produced by these adjustments equal $2.58 billion. In other words the company incurred $120 million in additional, uncontrollable "above-the-line" expenses because, for example, hydro was less than normal. Such cost changes would be reflected as upward or downward rate adjustment for the coming year (much like current over- and undercollections). Hearings would be held for this purpose if any party took issue with the accuracy of the recorded fuel expenses or the calculation of the pro forma adjustment.

If the Commission decided to leave the utilities any risk for all "below-the-line" fuel cost changes, this would be the end of the regulatory line for test year fuel expenses. That is to say, utility "X" would not recover the remaining $80 million by which its normalized rate year expenses exceeded the test year estimate. More likely, however, the Commission would want to apply a "dead band" concept as a limitation on possible fuel cost profits and losses. The deadband could be sized so that it would be large enough to create real incentives for cost minimization, but not so large as to impose unacceptable risks on the company or its shareholders.

Assume that the Commission has adopted a $50 million deadband for utility "X" in the forecast proceeding. In this instance, the "normalized" test year results would be compared with the adopted estimate to determine the magnitude of the difference (here $80 million). If the shortfall or excess amount fall within the adopted deadband, that would be the end of the matter.

If the difference between normalized and estimated costs fell outside the deadband, either upward or downward, (here it exceeds it by $30 million) the utility would include in its true-up filing a detailed itemization of the causes for the deviation in costs from the adopted estimate. Such factors could include higher or lower than anticipated oil costs, reduced or increased availability of coal, nuclear or geothermal generation, increased or decreased purchased power (if that is not treated above-the-line), higher heat rates due to forced outages at the more efficient thermal plants, etc. If actual normalized costs exceeded the deadband, the utility could seek to recover the additional costs above the deadband only by showing that those expenses (here $30 million) were unpredictable at the time the forecast was adopted, uncontrollable, and consistent with the overall policies approved in the projection case. If costs were incurred as a result of changes in policy or strategy, the utility would be required to show that such changes were reasonable due to factors unforeseeable at the time of the forecast.

> Likewise, if costs fell below the deadband level, staff or intervenors could show that the savings were not due to anyh action of the utility, but rather resulted from unpredictable and uncontrollable events. In either case, if the Commission found that costs above or below the deadband should flow to the ratepayers, rates could be adjusted prospectively in conjunction with the pro forma hydro adjustment.

As is apparent from its proposal, TURN is recommending a fundamental restructuring of the Commission's current regulatory framework while acknowledging its imperfections. TURN contends that its proposed reform is an appropriate first step toward a "return to normalcy" in California rate regulation.

C. Staff's Positions

Staff identifies four reasons why the current ECAC/AER procedures require reform: the current AER provides inconsistent incentives; utility shareholders are not exposed to significant risk with respect to energy expenses; the present ECAC/AER procedure provides no incentive for utilities to increase the use of renewable and alternative resources; and the present reasonableness review of utility energy operations is not sufficient to ensure that utilities have done the maximum to reduce energy expense.

All parties agree that the current mechanism which provides 100% recovery through the AER of certain oil inventory costs, such as underlifts, oil sale losses, and carrying charges, but recovery of only 2% of the remaining energy costs in the AER, produces perverse incentives for the utility.

Staff presented an example. Consider that early in the year, a utility has already incurred underlifts or losses on sales of oil up to the level estimated at the time the AER was set for the year. If the utility should decide that it could dispose of

additional excess oil in order to accommodate cheaper fuels, such as gas, the shareholders would pay the full cost of additional underlifts or oil sale losses. If, however, the utility rejected the cheaper fuels, and continued to burn oil so that it did not expose shareholders to the costs of additional underlifts, it would receive 98% of the cost of the oil burned (if the decision passed subsequent reasonableness review). In this way it is possible for the utility to perceive that it should increase the burning of oil in order to protect shareholders. This is contrary to the desired result.

All the Staff proposals resolve the problem by providing consistent rate treatment for all fuel-related expenses, including underlifts and the cost of burning oil. Under this approach both ratepayers and shareholders benefit if the least cost alternative is chosen. This occurs because the shareholders pay a constant percentage of whatever extra cost is required, and thus benefit if the lower cost path is chosen. Likewise, the ratepayers' rates will increase by a constant percentage of whatever excess costs are incurred, regardless of the particular expense item.

Staff maintains that the present ECAC/AER procedures do not contain any inherent incentive for the utility to increase use of renewable or alternative resources, since energy costs are recovered on a dollar-for-dollar basis. It makes no difference whether expensive oil or relatively cheap hydroelectricity is used, since the costs are passed on to the ratepayers to the same extent. Therefore, an objective of Staff's revision of the ratemaking procedures is to encourage the shift to renewable resources.

One of the factors of fuel expense over which management of the utility does have control is in the long-range choice of resources; the utilities can reduce their risk from price increases and supply insecurities by accelerating the replacement of fossil

fuel plants with renewable resources. The Staff contends that, if some risk of energy expense is placed upon the utilities, the path to renewables and alternative resources will become a logically attractive means to reduce the risk as much as possible. The Staff proposals are designed to place sufficient risk on the utilities to encourage cost-effective changes in the resource mix without imposing financial losses on the utility large enough to delay the program of conversion to renewable resources.

Prior to creation of the ECAC and its predecessor fuel cost adjustment procedures, utility shareholders bore the full risk of variations in energy expense from forecast levels. In Staff's view, the present system, with 98% of all fuel expenses recovered through the balancing account on a dollar-for-dollar basis, provides little or no incentive in the ratemaking process to encourage the utility to minimize costs. If a dollar is spent, it will be recovered, subject only to its passing the scrutiny of the reasonableness review.

Staff asserts that the experience of the past two years demonstrates that the reasonableness review of utility energy operations cannot be counted on to provide a complete and critical study of the utilities' efforts to provide a least cost resource mix. Staff also maintains that the reasonableness review process is fallible and cannot be expected to comprehend the whole system of energy operations of any utility.

Staff contends that the "reasonableness" showings of the utilities tend to be conclusory statements that expenses have been reasonable. Furthermore, such statements tend to be sponsored by witnesss with only general knowledge of the subject gained from others. There is little first-hand testimony.

Staff concludes that the reasonableness review should be maintained despite its limitations, because it provides unique

ability and flexibility to address unexpected issues and events. In addition, it is essential that the reviews continue so that Commission auditors can examine the utilities' books to see that expenses are properly accounted. However, Staff finds little reason for public confidence that the process of the reasonableness review alone is sufficient to ensure that the utilities are following a least cost energy strategy. Staff is also troubled by the fact that the Commission and the ratepayers must rely solely on an investigative process dependent upon those being investigated for its effectiveness. Staff concludes that the reasonableness review may be improved, and more vigorously implemented, and that it should be maintained. However, Staff feels that the public deserves a more certain and effective form of regulation -- a financial incentive that will induce the utilities to reduce energy costs for their own financial benefit.

Staff notes that the shareholders are currently willing to accept the risk of expense variation associated with items included in base rates, for which there is no balancing account recovery in a direct sense.[4] Staff argues that by imposing on the shareholders significant risk of expense variation, without exposing the utility to severe negative financial impacts, the Commission can give the utilities substantially more incentive to manage their energy costs.

The Staff argues that each of its proposals has a sound theoretical basis. Utilities Division's proposed mechanism is based upon the intuitively fair notion that if energy expenses vary, the shareholders and ratepayers should share in the consequences of that variation. Accordingly, the mechanism calculates a specific AER/ECAC allocation so that any given error in energy cost forecasts

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[4] The effects of the Electric Revenue Adjustment Mechanism (ERAM) are discussed below.

would change customer rates and shareholders' earnings by the same percentage. The calculation takes into account all elements of the revenue requirement, including base rates, the AER, ECAC, and other miscellaneous offset rates. For Edison, using data available from its recent general rate case, the appropriate AER/ECAC split is calculated to be 16%/84%.

By this proposal, Staff links the fortunes of shareholders and ratepayers. Any management decision which reduces costs will benefit the shareholders and the ratepayers by the same percentage. Furthermore, Staff pairs this concept with a limitation on the extent of earning variations which shareholders will be required to absorb, thereby preventing the financial consequences of extreme variation in costs from injuring the utilities' financial health. Under the proposed mechanism, the AER percentage and the expense variation limitations would be set every two years in general rate cases. The Staff contends that this mechanism will provide a short-run incentive for the utility to reduce energy costs and a long-run incentive to move to more stable forms of generation, thereby avoiding the price and supply instability associated with oil and gas.

The historical risk proposal of the Revenue Requirements Division calls for the allocation of expenses to the AER such that the investor will absorb energy costs to the point where the risk of nonrecovery of expenses for fuel-related items is comparable to that risk associated with other costs. This recommendation is based upon the fact that shareholders of the utility have always absorbed the risk of expense variation in virtually all categories of utility expense, including taxes, depreciation, and operation and maintenance costs. Staff reminds us that shareholders bore the cost of variation in energy expenses until the early 1970s when rapidly escalating fuel costs made the risk of such variation too high for the utility to sustain without frequent rate relief. In response the Commission created the fuel cost adjustment clauses.

The essence of this Staff proposal is to return to the investor that proportion of the risk of expense variation that is retained on nonfuel-related expenses. This proposal would an AER so that the largest expense variation in fuel costs would produce no greater earnings variation than the utilities' investors presently experience experience with other costs, as measured by variation from the authorized rate of return set by the Commission.

Variation in rate of return on rate base is used to gauge earnings volatility. The historical risk proposal assumes that the variation between authorized and realized rate of return is and will be an acceptable level of earnings variation for the shareholders to absorb. As was intended with the original creation of the ECAC mechanism, the ratepayers will assume expense variations in excess of that level to protect the utility from extraordinary fluctuations in energy costs. However, under Staff's second proposal ratepayers will no longer absorb virtually all risks of energy cost variations.

For purposes of illustration, the Staff witness used the period 1976 to 1981 as the base period from which to determine the risk of not earning the rate of return authorized by the Commission. In practice, a running average would be used to include the rate of return experience of the utility in the most recent years, although a span of several years should be used. Furthermore, the Staff made an allocation based upon the ratio of fuel expenses to nonfuel expenses for 1972 to avoid the effect of recent fuel price escalation in the proportion of fuel-related risk to be assumed by investors. This ratio could be adjustd, but the Staff recommends the use of the 31% energy costs/69% nonenergy costs ratio for the present to simulate the proportion of energy risk borne by investors prior to the enormous fuel price increases of the seventies. The result of these calculations is an AER of 13% and an ECAC allocation of 87%. The overall rate of return of the utility can vary by 0.35% under this allocation, matching the historical experience of 1972.

Staff argues that adoption of this method would place upon the shareholders a risk of variation in fuel expenses directly comparable to the risk they now bear for nonfuel expenses. For this reason, Staff concludes that the effect on the cost of capital should be minimal, particularly when combined with the earnings "cap" proposed by Revenue Requirements. The cap would provide a maximum earnings variation of approximately 5%, or 0.35% overall rate of return. The dollar impact of that swing on Edison's current system would be $26.3 million.

The Policy and Planning Division recommended that rate treatment for fuel expenses be split on a 20% AER/80% ECAC basis. The proposal is based on detailed analyses of the effect that earnings fluctuations might have on Edison's cost of capital. The witness concluded that the cost of capital would not be significantly changed if the 20% AER/80% ECAC proposal were adopted, combined with a 300 basis point limit on pretax variations in return on common equity.

In his analysis, the witness emphasized the importance of considering potential impact on the cost of equity separately from any impact on the cost of debt, since the owners and creditors perceive fuel-related risks quite differently. First, the witness argued that the cost of equity would not rise as a result of the proposed revision in current fuel expense allocation since any increase in earnings fluctuations would not be correlated with the aggregate economy. This conclusion is consistent with financial theory, and is well supported by numerous empirical studies.

Second, the witness concluded that the cost of debt would not rise significantly due to the proposed revision. He noted that the cost of debt is strongly related to cash coverage of interest; he had previously developed an econometric model which clearly demontrated the importance of interest coverage in determining bond yields. Based upon the staff projections of Edison's 1983 cost of

capital made in A.61138 (Exhibit 34c),and the staff analysis of fuel expense estimate error in this proceeding (Appendix A of staff report), the witness studied the effect that the proposed revision would have upon Edison's after tax interest coverage in a year of extremely underforecast fuel expense (assumed to occur one time in a forty-year period). The analysis indicates that a moderate reduction in interest coverage would occur, from 2.71 times to 2.57 times, since the 300 basis point limit protects the company from any greater erosion in coverage.

In making this proposal, the Policy Division witness recognized that the Commission might adopt an electric revenue adjustment mechanism (ERAM) in its decision for the general rate case, A.61138, which would protect Edison from revenue swings which might otherwise result from substantial misestimates of the total electric sales used to set rates during the test year. If such an ERAM mechanism were adopted, a major potential source of earnings erosion (which could reduce interest coverage) would be eliminated, substantially reducing the risk to Edison's bondholders.

The Staff contends that its three primary proposals represent major improvements and refinements of existing ECAC procedures. The unform treatment of all fuel-related expenses eliminates the perverse incentives present under the current system, and the increase in AER percentage places increased risk upon shareholders and ties their fortunes to the ratepayers. All utility actions to reduce the impacts of rising energy costs on shareholders will also benefit ratepayers. Staff maintains that this automatic mechanism will operate in conjunction with the reasonableness review to provide specialized review of specific transactions. The Staff feels that its proposals also resolve the problem of excess oil in inventory by allocating the costs between ratepayer and shareholder in a manner that will reduce revenue swings due to excess oil.

Accordingly, the Staff recommends that the Commission adopt one set of the Staff proposals.

Staff also presented a collection of secondary proposals, for the Commission to consider as supplements, or less-sweeping alternatives, to the primary recommendations. These secondary alternatives were recommended for adoption if the Commission were determined to make more limited changes in the AER/ECAC mechanism. The first, uniform treatment of all fuel-related expenses in AER/ECAC, is a severable element of Staff's primary proposals. The other secondary proposals would change slightly the calculation of return to Edison from some factors in the ECAC balance, would reduce the amounts of oil or gas cost changes eligible for treatment in ECAC, or would expand the applicability of power plant efficiency standards.

V. DISCUSSION

A. Background: Fuel Cost Adjustment Clauses.

The development of the current ECAC procedures can be traced to the early 1970s. Prior to that time, fuel costs were relatively stable, and were projected as normal costs of service in the infrequent general rate proceedings. In the early 1970s, several factors began to drive up energy costs rapidly: increases in the price of fuel oil; increased use of fuel oil due to a shortage of natural gas; and air pollution regulations which mandated the burning of more expensive, low-sulfur fuel oil. These price increases were not covered in base rates and therefore were absorbed by the utility.

The Commission recognized that a combination of general inflation and rapid changes in fuel costs had seriously impaired the utilities' financial integrity. In March of 1972, it authorized establishment of a Fuel Cost Adjustment (FCA) for Edison. The FCA was based on current rather than forecast oil and gas prices and a twelve-month forecast of loads and resources assuming normal hydro conditions. It recognized increases or decreases in Edison's fossil

fuel costs compared to the costs already reflected in base rates.[5]

Subsequent to adoption of FCA, above-average precipitation increased available hydro and purchased power and consequently lowered fuel costs. Large utility overcollections resulted, prompting the Commission in April, 1976 to abandon FCA and to adopt the original ECAC procedure. This ECAC procedure was designed to keep the utilities exactly whole for all of their reasonably incurred fuel and purchased power expenses. The ECAC rate was based on twelve-month recorded data and subject to semiannual revision. A balancing account approach, initially rejected for FCA, was adopted. The purpose of the balancing account is to accumulate the difference between ECAC revenues and expenses recorded each month. The balance in the account is reflected in subsequent adjustments by an Energy Cost Adjustment Billing Factor (ECABF).

During periods of increasing fuel costs, the gap between incurred and recovered costs would impair a utility's cash flow. Conversely, in a period of decreasing fuel costs, the ECAC would produce utility overcollections. In reaction to problems created by regulatory lag and controversy engendered by the use of recorded versus estimated fuel expenses, OII 56 was instituted in the fall of 1979, to analyze whether any changes should be made to the then existing ECAC procedure.

In a January 1980 interim opinion (D.91269), the Commission changed the ECAC to a more forward-looking basis and ordered the following basic revisions: from semiannual to triannual adjustments to the ECABF; from recorded to estimated resource mix; from recorded to estimated energy prices; from recorded to estimated sales; and

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[5] PG&E, SDG&E, and Sierra Pacific received authority to establish FCA mechanisms in 1973.

from a recorded to an estimated balancing account balance on the revision date. The Commission also recognized the appropriateness of a variable, rather than a fixed twelve-month, period for amortization of over- and undercollections.

In a second interim decision issued in OII 56 in January 1980 (D.91277), the Commission revised the balancing account interest rate from a fixed rate of 7% to the variable rate of commercial paper.

The final decision in OII 56 (D.92496, dated December 5, 1980) made permanent the changes instituted by the two interim decisions. Additionally, 2% of most annual fuel costs and 100% of certain expense items, such as underlift and facilities charges, gains and losses on oil sales, and carrying costs of oil in inventory, were excluded from ECAC. Prospective estimates of the reasonable levels of these expense items, including the 2% of fuel costs, were to be recovered in base rates through what is now called the AER. The ECAC procedure had reached its present stage.

B. Allocating Risks

As stated in the order (OII 82-04-02) which instituted this investigation:

> "Allocation of risk to utility shareholders has always been the central tool available under traditional regulation for encouraging efficient utility decision-making. While balancing accounts have been essential as a response to financial crisis in the short term, the risk reducing impacts of fuel cost adjustment clauses in the long term need to be addressed."

Our concern in this OII is therefore to find an appropriate allocation of risks between the ratepayers on one hand, and Edison's shareholders on the other. Edison must shoulder a high enough proportion of risk to assure the most attentive and efficient management of fuel-related expenses. At the same time, the level of

risk should not be so great that it cannot be borne without imposing significant increases in the utilities cost of capital. We will therefore limit Edison's exposure to earnings fluctuation. By capping such swings, Edison's ability to raise capital should be unaffected by today's decision.

1. The AER/ECAC Split

As described above, the present AER includes 2% of most fuel-related costs, but 100% of fuel oil inventory costs. All parties have agreed that this distinction has produced perverse incentives for the utility.

Consider, for example, a situation in which a utility were offered an unforecast opportunity to buy inexpensive purchased power, but would then have to reduce its oil burn. If the utility were thereby forced to "underlift" oil already contracted for or sell oil from inventory, it would lose 100% of the unforecast loss, but receive only 2% of the benefit of the less expensive purchased power. Even if the total cost of the purchased power plus the oil sale losses were less than the cost of burning the oil, the utility's direct financial incentive under the existing AER/ECAC mechanism would be to burn the oil.

We will eliminate this perverse regulatory incentive to utility management. Today's decision will provide for consideration of all fuel-related costs, including those related to fuel oil inventory, in both AER and ECAC. All fuel-related costs will receive the same 90%-10% allocation between ECAC and AER. Consistent with this decision to provide uniform treatment of all fuel-related expenses, we will reject Staff's secondary proposals to limit ECAC treatment of oil and gas, and to implement a broad range of power plant efficiency standards.

2. 10% AER/90% ECAC

Parties in this proceeding proposed a broad range of

regulatory treatments, ranging from the utilities' arguments for 100% balancing account treatments to TURN's proposal to consider fuel costs within an annual rate case. As we will explain below, neither extreme is appropriate. Instead, we will adopt a 10% AER/90% ECAC split for Edison.

The utilities' proposal is in direct conflict with our determination to return more of the risks of variation in fuel-related expenses to the utilities. Their proposed 100% balancing account treatment of all fuel-related costs would remove their direct financial stake in the outcome of fuel management decisions. The Commission's annual reasonableness review would then provide our only opportunity to review these decisions. It would be inappropriate to place such exclusive reliance on reasonableness review.

Fuel cost reasonableness reviews are difficult proceedings. In contrast to standard prospective ratemaking procedures, review proceedings must rely in large part on the records and recollections provided by the utility to reconstruct the knowledge and options available at the time particular decisions were made, and to separate what could reasonably have been foreseen at the time from what subsequently transpired. Under these circumstances, it is difficult to articulate a consistent set of easily-followed objective criteria. This lack of clarity increases the so-called "regulatory risks" faced by utility management.

The 2% AER was introduced in order to relieve utilities and the Commission of the burdens of exclusively retrospective evaluation of volatile fuel-related costs. The same principles guide today's decision. Since the shareholders will be directly at risk.

management will have an enhanced incentive to minimize costs at the time each decision is made; this reduces the relative importantce of after-the-fact evaluation by the Commission.

The utilities cite as "disadvantages" of a larger AER the enhanced incentive to spend money on forecasting, and to attempt to ensure against unpredictable fuel swings by fixed-price contracts with suppliers. Neither response, if reasonably limited is inappropriate. Ratepayers also have an interest in price predictability and stability. Accurate forecasts can both reduce disruptive surprises, and draw attention to those areas of fuel-cost management which warrant the most attention. We will continue to review Edison's fuel-related decisions in the course of existing procedures: budget for forecasting in rate cases; fuel purchases in ECAC annual reviews; and proposed facility investment decisions in certification proceedings. This regulatory review should ensure that unreasonable decisions are not made in the search for stability.

The utilities also claim that any attempts they make to minimize fuel costs will be overwhelmed by unpredictable and "uncontrollable" variations in price and supply. We do not agree. We are persuaded by Staff's arguments that utility management has significant influence over fuel expenses, particularly in the long run. In the short term, management can improve operations and forecasting accuracy and in the long term reduce the utility's dependence on fuel oil and natural gas through capital investment, and cost-effective conservation and load management programs.

We agree with the staff arguments that Edison and its ratepayers should share the costs and benefits of fuel management decisions. However, in the interest of caution, and in recognition of the fact that any proposed split must be based on assumptions that ultimately depend on reasoned judgment, we will adopt a 10% AER forEdison. This figure falls below the 13% to 20% range encompassed by

the three staff proposals. However, it does provide a significant increase in the shareholders' proportion of the risk of most fuel-related decisions while reducing the risks presently associated with managing fuel oil inventories. We may in the future consider further enlargement of the AER share.

In adopting this procedure, we reject TURN's proposal for three principal reasons. First, it would maintain the artificial distinction between "controllable" and "uncontrollable" expenses. Second, this distinction would perpetuate the perverse incentives contained in the present AER/ECAC mechanism. Third, TURN's proposal would impose unreasonable administrative burdens.

3. A cap on AER-induced earnings fluctuations.

We agree with the parties in this proceeding that a reasonable limitation should be placed on the total risks to shareholders of fuel cost changes. Further, we agree with Staff that the most appropriate way to limit these risks is to cap the size of the adjustment. We reject TURN's proposal to narrow the types of variations to which shareholders are exposed, but to leave the shareholders' potential exposure unlimited. As explained above, we prefer more uniform regulatory treatment, unencumbered by artificial distinctions among types of fuel.

One of our principal concerns in selecting a cap on potential AER-related earnings adjustments is to avoid increasing Edison's cost of capital. We believe that Edison's shareholders can bear a limited share of fuel-related risks without raising the costs of capital. This is particularly true since today's decision reduces Edison's share of the risk of losses associated with fuel oil inventory from 100% to 10%, by revising the AER/ECAC split. Further, the cap adopted today also eliminates the unlimited potential exposure which Edison presently faces on 2% of other fuel costs.

The Policy and Planning Division witness argued that fuel-

related fluctuations of up to 300 basis points on pretax return on equity would be tolerated by Edison's shareholders and bondholders without significantly increasing Edison's cost of capital. He argued that this would represent a small potential variation in shareholders' return and that years of positive and negative adjustment should average out over time, so that expected return over time is unaffected. The witness also presented analysis that the proposed cap was also low enough to reassure bondholders that only minimal changes in cash coverage of interest due on debt could occur.

The witness' evaluation of the impacts on costs of capital of a 300 basis point cap may well be valid. Furthermore, our adoption of ERAM in D. 82-12-55 in A.61138, Edison's test year 1983 rate case, eliminates the risk to Edison of electric sales swings, which has been a major source of financial risk to Edison's shareholders and bondholders. In the interest of caution, however, we will set a cap of 160 basis points on variations in pretax return on common equity. Such a cap should produce no measurable increase in Edison's capital costs.

The 160 basis point cap and 10% AER will keep Edison's shareholders partially at risk for all unforecast price changes in 1983 of less than $498 million. This calculation is based on staff's forescasto of Edison's 1983 rate base of $7,412,400,000 and a capital structure which includes 42.0% common equity. In D.82-12-55, we adopted a rate base of $4,768,171,000 for 1983; the greatest difference from Staff's earlier forecast results from the continued exclusion of additional nuclear generation facilities from the rate base. Using the adopted rate base, Edison will be at risk for $32.04 million in 1983; inclusion of the nuclear plant in rate base would increase this exposure.

Staff has estimated that such unforecast fluctuations will rarely exceed $500 million in a given year. This range should be

narrowed further by making the AER calculation in the spring of each year, when more accurate forecasts of in-state hydroelectric supplies are available. This and other procedural issues are discussed in the next section.

C. Implementing the new AER/ECAC mechanism.

Today's decision establishes the basic elements of Edison's new AER/ECAC mechanism. A number of important procedural questions remain to be resolved. Also, a number of procedural changes proposed by Staff and others are not disposed of by this decision. Further hearings will be held to address the questions set forth below.

First, as indicated in the order which instituted this investigation, although we limited the factual analysis to Edison, we fully intend that the approach established in this proceeding be subsequently applied to the other electric companies within our jurisdiction. We have made a policy determination that all fuel-related expense be recovered through a combination of the AER and ECAC rates. For Edison, we have decided that the reasonable allocation for fuel-expense recovery is 10% through the AER and 90% through the ECAC, subject to a 160 basis point cap on variations in pretax earnings on common equity. This combination leaves the shareholders with a share of the risk of most fuel-related expense changes.

Substantial differences exist among the electric utilties under our jurisdiction. For each company specific circumstances must be taken into account in determining an appropriate allocation of fuel expense between AER and ECAC rates. We will issue this decision on an interim basis and here name PG&E, SDG&E and Sierra Pacific as respondents to the next phase of this proceeding. These new respondents will be expected to file, within 30 days of the effective date of this order, the data necessary to permit determination of the proper allocation of fuel-expense recovery between the AER and ECAC

rates. The required data are specified in detail in Appendix B, attached to this order. The further hearing in this proceeding will address these filings, and will not be used to relitigate the policy determinations reached in this decision.

Second, Edison and Staff will be directed to set forth the specific terms of tariffs embodying the changes in ECAC which we are ordering today. Edison and Staff should also include, at the hearing, a proposed accounting treatment for the adopted cap on AER-related earnings fluctuations. The proposed accounting treatment should be consistent with Staff's suggestion that Edison track its total revenues and AER revenues in a manner similar to the ERAM in place for PG&E and SDG&E, and adopted in A.61138 for Edison. Similarly, the three additional respondents named above should be prepared to propose the specific terms of tariffs and the accounting treatment through which changes in their AER/ECAC allocation would be implemented.

Third, at the hearing all respondents and the Staff will be expected to address the issue of the appropriate interest rate to be allowed for fuel inventories. Analyses should include consideration of whether rates might appropriately differ between amounts of for oil up to the adopted operational level as opposed to amounts above that volume.

Fourth, the implementation schedule and other procedural details may be modified by the decision in Order Instituting Investigation (Rulemaking Proceeding) 82-09-02 (procedural OII) which is the Commission's concurrent investigation "for the purpose of establishing standards for the filing and content of gas and electric offset rate proceedings and to revise the current procedures and schedules for the filing of such applications." The procedural OII further is charged "to consider reducing the number of offset filings per year and to coordinate gas and electric offset rate

proceedings". Until the procedural OII is concluded the new schedule of ECAC filings for other utilities will not be known.

However, implementation for Edison should not be delayed. The AER/ECAC split adopted here for Edison should be placed in effect in the first new twelve-month AER period. This date is presently May 1, 1983, but is subject to change by decision in OII 82-09-02.

The decision in OII 82-09-02 should address the feasibility of an AER/ECAC schedule which allows time for analysis of snow-pack and precipitation data in the spring. The uncertainty in forecast fuel mix would be substantially reduced if the AER is set after California hydroelectric supplies can be forecast confidently and the best possible estimate of imported hydroelectric-based purchased power supplies can be made.

We will also leave to OII 82-09-02 the resolution of PG&E's recommendation to bifurcate the annual reasonableness review, and the actual establishment of the annual forecast of fuel-related costs.

VI. CONCLUSION

Today's decision continues the process, begun in OII 56, of determining an appropriate balance between forecast-year ratemaking and balancing account retrospective ratemaking for fuel-related expenses and transactions. The new AER/ECAC mechanism will provide Edison's management with a strong incentive to manage fuel-related expenses efficiently, but will limit Edison's total risk in order to avoid any chance of compromising the utility's ability to raise capital.

Up to the limit imposed by the 160 basis point cap, Edison's shareholders will share the burdens and benefits of fuel-related decisions on ratepayers' rates. At the adopted 10% AER, the shareholders receive one-tenth of such fluctuations. With the adopted 1983 ratebase, Edison would receive its maximum adjustment of $32 million if fuel-cost forecasts erred by roughly $320 million,

which would mean an unforecast change of roughly 15% of fuel cost. If fuel costs unexpectedly rose $320 million (e.g., in response to an exceptionally dry year, a major OPEC price increase, or unexpected outages of several large Edison power plants) the ratepayers would face an increase of just under $290 million, while Edison's shareholders' pretax return on equity would fall by $32 million. If fuel expenses dropped $320 million (because of a wet year, OPEC collapse, and/or exceptionally efficient operation of power plants), Edison's shareholders could receive a pretax bonus of $32 million while the ratepayers could receive a $290 million reduction in rates.

We recognize that the evidence suggests that fuel-related expense variations can be as large as $500 million. This is considerably larger than the $320 million swing which would drive Edison's AER-related earnings fluctuation to the cap. However, we anticipate that the reasonable expenses associated with SONGS 2 and 3, and the Palo Verde units will be passed into Edison's rate base after those units become used ann useful. After that time, the 160 basis point cap would embrace a larger range of fuel-related expense variations.

Findings of Fact

1. Fuel cost adjustment procedures were developed in response to dramatically escalating and unpredictable energy costs encountered by California's regulated electric utilities in the early 1970s.

2. Under current AER/ECAC procedures, utility ratepayers bear the predominant share of the risk that actual energy expenses will vary from estimated expenses.

3. Current AER/ECAC procedures protect the financial integrity of the utilities from the impact of unpredictable, constantly escalating fuel prices.

4. An increase in the proportion of financial risk of fuel-related expenses imposed upon utility shareholders will operate as a further incentive to Edison's management to most efficiently control its energy costs.

5. The TURN proposal is an inefficient and impractical method to reallocate the risks and rewards created by the AER/ECAC between ratepayers and shareholders.

6. It is appropriate to provide consistent rate treatment for all fuel-related expenses by including all such expenses in both the AER and ECAC and giving them equal percentage recovery.

7. The adopted 10% AER/90% ECAC split will further induce Edison to control its costs.

8. Adoption of an earnings cap of 160 basis points on pretax return on common equity will limit the maximum financial risk borne by Edison shareholders under the revised AER/ECAC to roughly $32.04 million in 1983, based on the rate base and capital structure adopted in D.82-12-55 in A.61138, Edison's test year 1983 rate proceeding.

9. Costs incurred beyond the adopted earnings will be subject to balancing account recovery; to the extent Edison's fuels management produces savings up to the amount of the earnings cap, its shareholders will retain the benefits.

10. Our revisions to the AER/ECAC, when viewed in combination with the 160 basis point cap on variations in return on common equity, will not have a significant impact upon Edison's cost of capital.

11. Under the adopted AER/ECAC revisions, the carrying cost of oil in inventory, underlift charges, facilities charges, and gains or losses from sale of oil inventory are afforded the same treatment as all other energy-related expenses through the 10% AER/90% ECAC allocation.

12. To the extent feasible, it is reasonable to time the date of the fuel mix projection to include complete winter precipitation data.

13. PG&E, SDG&E, Sierra Pacific, and SoCal Gas participated fully in this proceeding.

14. In order that the changes in Edison's AER and ECAC procedures can be implemented at Edison's next annual reasonableness review, it is appropriate that this order be made effective today.

Conclusions of Law

1. The Commission should revise the AER/ECAC to more appropriately allocate the risk that actual energy expenses will vary from estimated expenses between Edison's ratepayers and shareholders.

2. The Commission should adopt a 10% AER/90% ECAC procedure for Edison, with all fuel-related expenses afforded consistent treatment.

3. The Commission should adopt a cap of 160 basis points on variations in pretax return on common equity, to limit the maximum financial gain or loss potentially incurred by Edison's shareholders under the revised AER/ECAC procedures.

4. The Commission should name PG&E, SDG&E, and Sierra Pacific as respondents to this investigation and address through further hearing the appropriate allocation of rate recovery between the AER and ECAC for all fuel-related expense. The three respondents should file with the Commission all data necessary to determine the appropriate AER/ECAC allocation.

5. Further hearing should be held in OII 82-04-02 to allow review of the exact terms of proposed tariffs which embody the changes in the AER/ECAC which have been adopted today.

6. Specified details for implementing the adopted changes in AER/ECAC procedures should be addressed in OII 82-09-02; however, the decision in Edison's next annual reasonableness review should not be delayed.

7. This order should be made effective today, in order to ensure that the changes in Edison's AER and ECAC procedures can be implemented at Edison's next annual reasonableness review.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) shall file within 30 days of the effective date of this order a proposed tariff containing revisions to its AER/ECAC procedure consistent with this decision.

2. The Commission Staff shall file within 45 days of the effective date of this order a proposed tariff reflecting revisions to Edison's AER/ECAC procedure consistent with this decision.

3. Revisions to Edison's AER/ECAC procedure consistent with this decision shall be included in the order concluding Edison's next annual reasonableness review, now scheduled for May 1, 1983, so that Edison will be subject to the revised procedure during 1983-1984.

4. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Sierra Pacific Power Company (Sierra Pacific) shall each be a respondent in all further phases of this investigation.

5. PG&E, SDG&E, and Sierra Pacific shall each file an original and 12 copies of the compliance data as specified in Appendix B of this order within 30 days of the effective date of this order.

6. Further hearings shall be held in OII 82-04-02, in San Francisco. These hearings shall address: the proposed tariffs filed by Edison and the Staff; Edison's proposed accounting treatment for the adopted cap on earnings fluctuation; and, for PG&E, SDG&E and

Sierra Pacific, the appropriate allocation of fuel-related expense for rate recovery between the AER and ECAC.

This order is effective today.

Dated DEC 22 1982 at San Francisco, California.

JOHN E. BRYSON
President
RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

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

Joseph E. Bodovitz, Executive Director

APPENDIX A

List of Appearances

Respondent: John R. Bury, David N. Barry, III, Richard K. Durant, Carol B. Henningson, and James M. Lehrer, Attorneys at Law, for Southern California Edison Company.

Interested Parties: William L. Knecht, Attorney at Law, for California Association of Utility Shareholders; John W. Witt, City Attorney, by William S. Shaffran, Deputy City Attorney, for City of San Diego; Randall W. Childress, William Reed, and Jeffrey Guttero, Attorneys at Law, for San Diego Gas & Electric Company; Graham & James, by Boris H. Lakusta, David J. Marchant, Thomas J. MacBride, Jr., Ann C. Pongrancz, Attorney at Law and James B. Henly, for Sierra Pacific Power Company; Harry K. Winters, for the University of California; Jane S. Kumin, Attorney at Law, for Natomas Company and Thermal Power Company; Antone S. Bulich, Jr., Attorney at Law, for California Farm Bureau Federation; Robert M. Loch, Jeffrey E. Jackson, and Thomas D. Clarke, Attorneys at Law, for Southern California Gas Company; Daniel E. Gibson, Shirley Woo, and Steven Greenwald, Attorneys at Law, for Pacific Gas and Electric Company; Nancy R. Teater, for Stanford University; Roger Dickinson, Attorney at Law, for California Department of Consumer Affairs; Robert Spertus and Michel Peter Florio, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Catherine A. Johnson, Attorney at Law, for California Energy Commission; and Robert E. Burt, for California Manufacturers Association.

Commission Staff: Timothy E. Treacy and Michael B. Day, Attorneys at Law, William R. Stalder, and Raymond A. Charvez.

(END OF APPENDIX A)

Appendix B

Description of Data To Be Provided by PG&E, SDG&E and Sierra Pacific

Fuel Forecast Data

1. a. All twelve-month calendar year forecasts developed within the last 15 years of;

   i. Energy production by resource type including purchased power (GWh).

   ii. Total generation and sales (GWh).

   iii. Twelve-month average total and operational oil inventory levels.

   b. If twelve-month forecasts for other than a calendar year basis are available, and the company believes they are significantly more accurate or precise, they should also be submitted.

2. Recorded twelve-month data corresponding to the items in 1a and 1b, above.

3. Forecasts for the forthcoming AER year (preliminary, if necessary) of:

i. Resource mix, GWh by type.
ii. Heat rates, by resource type.
iii. Fuel prices, by resource type.
iv. Total generation and sales.
v. Operational oil inventory level.
vi. Economic excess oil inventory level.

Financial Data

The following data must be provided on both a recorded basis for 1982 (as of December 31, 1982 if available, otherwise of September 30, 1982) and on an estimated basis for 1983.

- Total Sales Revenues for the twelve months
  - o Percent of revenue attributed to electric sales

- Interest Expense for the twelve months

- Total Debt Service (including interest and payments to all sinking funds) for the twelve months

- Total Rate Base
  - o Percent of rate base attributed to electric service

- Total Value of Current Liabilities

- Total Value of Long-Term Liabilities

- Total Value of Common Equity

- Total Value of Preferred Stock

- Effect on after-tax earnings available for common stock in:
  total dollars
  per share of common stock
  rate of return on equity
  comparing recorded earnings with pro forma earnings assuming no balancing account from inception of ECAC to present.

(End of Appendix B)

regulatory treatments, ranging from the utilities' arguments for 100% balancing account treatments to TURN's proposal to consider fuel costs within an annual rate case. As we will explain below, neither extreme is appropriate. Instead, we will adopt a 10% AER/90% ECAC split for Edison.

The utilities' proposal is in direct conflict with our determination to return more of the risks of variation in fuel-related expenses to the utilities. Their proposed 100% balancing account treatment of all fuel-related costs would remove their direct financial stake in the outcome of fuel management decisions. The Commission's annual reasonableness review would then provide our only opportunity to review these decisions. It would be inappropriate to place such exclusive reliance on reasonableness review.

Reasonableness reviews are ~~extraordinarily~~ difficult proceedings. In contrast to standard prospective ratemaking procedures, review proceedings must rely in large part on the records and recollections provided by the utility to reconstruct the knowledge and options available at the time particular decisions were made, and to separate what could reasonably have been foreseen at the time from what subsequently transpired. ~~This after-the-fact investigation is not only inherently difficult, but requires our Staff to perform tasks which are outside the range of activities generally considered appropriate to ratemaking. Under these circumstances, it is impossible~~ to articulate a consistent set of easily-followed objective criteria. This lack of clarity increases the so-called "regulatory risks" faced by utility management.

The 2% AER was introduced in order to relieve utilities and the Commission of the burdens of exclusively retrospective evaluation of volatile fuel-related costs. The same principles guide today's decision. Since the shareholders will be directly at risk,

7. This order should be made effective today, in order to ensure that the changes in Edison's AER and ECAC procedures can be implemented at Edison's next annual reasonableness review.

INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) shall file within 30 days of the effective date of this order a proposed tariff containing revisions to its AER/ECAC procedure consistent with this decision.

2. The Commission Staff shall file within 45 days of the effective date of this order a similar proposed tariff reflecting revisions to Edison's AER/ECAC procedure consistent with this decision.

3. Revisions to Edison's AER/ECAC procedure consistent with this decision shall be included in the order concluding Edison's next annual reasonableness review, now scheduled for May 1, 1983, so that Edison will be subject to the revised procedure during 1983-1984.

4. Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), and Sierra Pacific Power Company (Sierra Pacific) shall each be a respondent in all further phases of this investigation.

5. PG&E, SDG&E, and Sierra Pacific shall each file data as specified in Appendix B of this order within 30 days of the effective date of this order.

6. Further hearings shall be held in OII 82-04-02, in San Francisco. These hearings shall address: the proposed tariffs filed by Edison and the Staff; Edison's proposed accounting treatment for the adopted cap on earnings fluctuation; and, for PG&E, SDG&E and

APPENDIX A

List of Appearances

Respondent: John R. Bury, David N. Barry, III, Richard K. Durant, Carol B. Henningson, and James M. Lehrer, Attorneys at Law, for Southern California Edison Company.

Interested Parties: William L. Knecht, Attorney at Law, for California Association of Utility Shareholders; John W. Witt, City Attorney, by William S. Shaffran, Deputy City Attorney, for City of San Diego; Randall W. Childress, William Reed, and Jeffrey Guttero, Attorneys at Law, for San Diego Gas & Electric Company; Graham & James, by Boris H. Lakusta, David J. Marchant, Thomas J. MacBride, Jr., Ann C. Pongrancz, and James B. Henly, Attorneys at Law, for Sierra Pacific Power Company; Harry K. Winters, for the University of California; James S. Kumin, Attorney at Law, for Natomas Company and Thermal Power Company; Antone S. Bulich, Jr., Attorney at Law, for California Farm Bureau Federation; Robert M. Loch, Jeffrey E. Jackson, and Thomas D. Clarke, Attorneys at Law, for Southern California Gas Company; Daniel E. Gibson, Shirley Woo, and Steven Greenwald, Attorneys at Law, for Pacific Gas and Electric Company; Nancy R. Teater, for Stanford University; Roger Dickinson, Attorney at Law, for California Department of Consumer Affairs; Robert Spertus and Michel Peter Florio, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Catherine A. Johnson, Attorney at Law, for California Energy Commission; and Robert E. Burt, for California Manufacturers Association.

Commission Staff: Timothy E. Treacy and Michael B. Day, Attorneys at Law, William R. Stalder, and Raymond A. Charvez.

(END OF APPENDIX A)