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Decision 91-12-076 December 20, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for Authority to Increase its Authorized Level of Base Rate Revenue Under the Electric Revenue Adjustment Mechanism for Service Rendered Beginning January 1, 1992 and to Reflect this Increase in Rates.	Application 90-12-018 (Filed December 7, 1990)
And Related Matters.	I.89-12-025 (Filed December 18, 1989) I.91-02-079 (Filed February 21, 1991)

FOURTH INTERIM OPINION: PHASE 1 ISSUES

(See Appendix A for appearances.)

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1. Summary of Decision

This Fourth Interim Opinion decides Phase 1 issues in the test year 1992 general rate case (GRC) of Southern California Edison Company (Edison). The major issues are test year revenue requirement; productivity; marginal costs; research, development, and demonstration (RD&D) activities; demand-side management (DSM); and a return on equity (ROE) penalty proposed by the Division of Ratepayer Advocates (DRA).

The principal result of the decision is authorization of base rate revenue requirement, which is identified in Edison's tariffs as the Authorized Level of Base Rate Revenue (ALBRR). Base rate expenses account for roughly one half of Edison's annual operations. The remainder is fuel-related expenses, considered in Energy Cost Adjustment Clause (ECAC) proceedings. The adopted ALBRR is $4,012 million, which is 1.3% greater than Edison's present ALBRR and 3.9% less than the ALBRR requested by Edison. The adopted ALBRR will be used to set 1992 base rates in Application (A.) 91-05-050, Edison's current ECAC proceeding. The impact of this decision will be to increase Edison's overall rates by 0.7%.

Expense adjustments for Edison's Cost Containment program is a factor in the ALBRR reduction. The Commission finds that Edison should share by 50% its 1.5% Cost Containment savings. This adjustment is applied to controllable operations and maintenance expenses, which exclude fuel-related costs, employee health care benefits, RD&D, DSM, and certain other expenses. The revenue impact of the adjustment is $37.4 million.

The parties have generally agreed on determination of Edison's marginal costs. The adopted marginal costs will be used in Phase 2 of the GRC, which considers revenue allocation and rate design issues.

This decision authorizes $56 million in expenses for test year RD&D activities and $141 million for DSM programs. The DSM expenses are double the amount authorized in Edison's test year 1988 GRC, on a constant dollar basis.

Edison is authorized to begin an interim program of DSM shared savings incentives. Shareholders will be paid a percentage of the value of the energy saved by eligible DSM programs. If Edison meets its test year energy savings goals, shareholders will receive about $7 million in incentive payments. Shared savings and other DSM policy issues are deferred to Rulemaking (R.) 91-08-003 and Investigation (I.) 91-08-002, the DSM rulemaking.

The Commission declines to impose on Edison an ROE penalty for failure to provide information regarding affiliated qualifying facilities (QFs). Edison has failed to meet Commission standards for providing information, but an ROE penalty is not the most effective remedy. The record on a second penalty, for favoritism to affiliated QFs, is held open until reasonableness issues are decided in Edison's consolidated 1989, 1990, and 1991 ECAC proceedings. Possible disallowances for imprudent management of nuclear plant refueling outages are referred to ECAC proceedings, because the harm to ratepayers is excessive fuel-related costs. A penalty for the imprudence, if justified, will be considered in Edison's next GRC.

2. Procedural Background

This consolidated proceeding is Edison's test year 1992 GRC. Edison's last GRC was for test year 1988. At that time the Commission anticipated that the next GRC would be for test year

1991, but a one year deferral was granted in Decision (D.) 89-08-036.[1]

In accordance with the Rate Case Plan adopted in D.89-01-040,[2] on August 31, 1990 Edison tendered its Notice of Intent (NOI) for a test year 1992 GRC. The NOI was accepted for filing on October 5, 1990, and Edison filed A.90-12-018 on December 7, 1990. Edison amended A.90-12-018 on March 7, 1991, to submit Phase 2 testimony. On December 18, 1989 the Commission instituted I.89-12-025, concerning lengthy outages at Units 1 and 3 of Palo Verde Nuclear Generating Station (Palo Verde 1 and Palo Verde 3), in which Edison has an ownership share. I.89-12-025 was consolidated with the GRC by Administrative Law Judges' (ALJs') ruling dated February 1, 1991, in compliance with Public Utilities (PU) Code § 455.5(c). On February 21, 1991 the Commission opened and consolidated with the GRC I.91-02-079, which is a procedural forum to investigate revenue requirement, rates, practices, and other aspects of Edison's operations which may lie outside the scope of A.90-12-018.

The consolidated proceeding has thus far been divided into four separate phases: Phase 1 on revenue requirement, marginal costs, and DSM; Phase 2 on revenue allocation and rate design; Phase 3 on the Palo Verde outages; and an anticipated Phase 4 on affiliate transactions.

The first Interim Opinion, D.91-03-058, removed from the GRC the issue of the cost-effectiveness of capital additions to San Onofre Nuclear Generating Station, Unit 1 (SONGS 1), for which Edison is the operator and majority owner. The issue now resides in I.89-07-004, the Biennial Resource Planning Update. The Second

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1 32 Cal. PUC 2d 372 (1989).

2 30 Cal. PUC 2d 576, 601 (1989).

Interim Opinion, D.91-04-070, authorized ratemaking treatment of two proposed capital projects under the Major Additions Adjustment Clause (MAAC) in Edison's tariffs, rather than treatment under PU Code § 1005.5 as requested by Edison. The Third Interim Opinion, D.91-07-051, modified the terms of I.89-12-025 to recognize that Palo Verde Units 1 and 3 have been returned to service. This Fourth Interim Opinion covers remaining Phase 1 issues.

A prehearing conference was convened on January 11, 1991, followed by a procedural ruling from assigned ALJs James Weil and Mark Wetzell. Public participation hearings were held in six communities within Edison's service territory. Fifty days of evidentiary hearings were held during Phase 1; concurrent opening and reply briefs were filed on July 31 and August 14, 1991. Phase 1 was submitted at the conclusion of technical update hearings on September 23, 1991.

In A.90-12-018 Edison sought an increase in its ALBRR of approximately $440 million, including certain amounts which had been authorized by the Commission but were not yet effective on the date A.90-12-018 was filed. When opening briefs were filed, after other revenue requirement increases became effective and after several stipulations were made by Edison, the amount of the requested increase had been reduced to $191.364 million, relative to estimated margin effective December 31, 1991.

3. Sales, Customers, and Present Rate Revenues

The estimates presented by both Edison and DRA for test year sales were developed using econometric models that relate electricity consumption to economic and weather conditions. The two forecasts differ primarily due to assumptions used for: (1) customer bypass, (2) energy conservation programs identified in

A.90-04-036, Edison's application in the "collaborative process," and (3) weather conditions affecting agricultural sales.

Edison believes that sales will decline in response to an additional 1,500 gigawatt-hours (GWh) of bypass not captured in existing trends or identified in collaborative process programs. DRA argues that those two factors are included in historical trends, and that agricultural sales should be forecast assuming continuation of the California drought, which had persisted for five years as of the summer of 1991.

The positions of Edison and DRA apply only to Phase 1 of the GRC. Sales and customers affect revenue requirement in four areas: (1) jurisdictional allocation factors, (2) the user tax element of working cash, (3) postage expense, and (4) Edison's escalation of administrative and general (A&G) expenses. Both parties argue that recent sales estimates filed in A.91-05-050, Edison's current ECAC proceeding, should be used for revenue allocation and rate design in Phase 2. The California Farm Bureau Federation (CFBF), the only other party presenting sales forecast testimony, disagreed. CFBF supports Edison's GRC forecast, but believes the adopted GRC forecasts should be applied in the ECAC proceeding. CFBF also argues that Edison's sales forecast, which is lower than DRA's, is more reasonable because continued dry conditions and the extensive freeze during the winter of 1990-1991 will result in acreage being taken out of production, offsetting increased pumping load.

The ECAC forecast is based on more recent data, but that forecast is not yet on the record in the GRC. We must rely on the record evidence to determine revenue requirement in Phase 1. However, all parties should be prepared to revisit sales and customer forecasts in Phase 2, for revenue allocation and rate design purposes. (This warning repeats the instructions of ALJs Wetzell and Weil in an ALJ ruling dated October 7, 1991.)

For Phase 1 purposes we will adopt the DRA forecasts, with an adjustment for agricultural and pumping sales to allow for average weather and stream flow conditions in the test year. DRA's forecasts are based on the most recent data available, and Edison has not adequately supported its adjustments for additional conservation and customer bypass. We reject DRA's assumption of drought conditions for the agricultural and pumping customer group. Average weather in the test year is more likely than continuation of the drought.

The adopted sales and customer forecasts are shown in Appendix B. The only adjustment to DRA's forecasts is made by setting agricultural and pumping group sales equal to the same fraction of total sales that was derived by Edison.

Only Edison and DRA presented testimony on present rate revenues. The differences between Edison and DRA are the result of their different sales forecasts. There is no dispute over how to calculate present rate revenues once sales and customer figures are adopted. The adopted present rate revenues are shown in Appendix B to this decision.

4. Employee Compensation

In Edison's last GRC, DRA recommended a 9.2% reduction in salary levels for administrative, professional, and supervisory employees, based on a comparison of Edison salary levels and wage surveys of other firms. The Commission rejected DRA's proposal because comparisons should be on a total compensation basis (or adjusted to reflect employee benefits), and because DRA's study was statistically inadequate. The Commission ordered Edison and DRA to jointly develop an employee compensation data base for use in this GRC.[3] In the test year 1990 GRC of Pacific Gas and Electric

3 Ordering Paragraph 26, D.87-12-066; 26 Cal. PUC 2d 392, 457 and 614 (1987).

Company (PG&E), DRA recommended a 6.64% reduction in labor expenses, based on another salary survey. The Commission again rejected DRA's adjustment, due to weak matching of jobs in the survey, failure to compare total compensation levels, and lack of data ranges.

In this proceeding, DRA and Edison have made progress in some areas, but not in others. The two parties agreed on the matching of Edison employee and survey positions and on the appropriate adjustments of wage and salary data for comparability. However, the comparison still excludes employee benefits. DRA witness Martin Lyons testified that it is more accurate and valid to compare cash compensation separate from benefits.[4]

DRA testified that Edison's wages and salaries are 2.88% higher than market averages, but DRA's study does not show market compensation distributions. It is uncertain where the 2.88% average differential puts Edison in a ranking of corporate compensation levels. For example, is Edison's compensation in the top 49% for comparable firms, or the top 1%? The results of DRA's study are shown in Table 1 below:

TABLE 1

Summary of Wage and Salary Survey Results

Occupational Category	Edison Exceeds Market	Payroll Weighting	Net Impact
Clerical	(1.90)%	16.9%	(0.32)%
Physical	7.84	31.6	2.48
Prof./Technical	1.98	31.0	0.61
Sup./Manager	0.98	20.0	0.20
Executive	(17.10)	0.5	(0.09)
Total	--	100.0%	2.88%

4 Tr. 20:1759.

DRA seeks two results from the Commission: (1) adoption of market parity as the objective standard for the reasonableness of utility wage and salary expense, and (2) a 2.8% reduction in Edison's labor expense, amounting to about $17 million, based on the adopted standard.

Edison opposed DRA's recommendation, arguing that: (1) the data base should not be used to specify reasonable expenses, but only to show that Edison's requested expenses are not clearly unreasonable, and (2) DRA's study is flawed because it contains inherent errors of at least 5%, subsuming the 2.88% average wage and salary differential. Edison's rebuttal witness Dennis Spry testified that compensation levels within 5% of levels for comparable firms are "at market," but his testimony is compromised by his misunderstanding of the burden of proof in the Commission's regulatory process. He testified that Edison should be granted all of its requested expenses unless DRA clearly shows that the expenses are unreasonable. We decline to shift the burden of proof to DRA.

Although we continue to pursue rigorous, analytical standards for employee compensation, DRA's recommendations are not justified. We do not have before us evidence to support market parity as a reasonable standard for total compensation. DRA's wage and salary study is useful, and statistical failings have been resolved, but elsewhere in its testimony DRA uses entirely different standards for both health care and non-health care benefits. Even Edison's witness on non-health care benefits believes that the Commission should review wages and salaries together with benefits.[5] We must reject DRA's $17 million reduction because DRA does not fairly compare all of the elements of employee compensation, and we do not know where the 2.88%

5 Testimony of Alfred Cain, Tr. 16:1200.

differential and employee benefits place Edison in relation to comparable firms.

We are disturbed that we must again authorize labor expenses based on trends and averages of historical expenses, but the record evidence forces us to do so. We question whether labor expenses 2.88% higher than the market average are necessary for delivery of safe, reliable service at reasonable rates, but we reluctantly find that Edison's wage and salary levels are reasonable.

We will order Edison and DRA to continue their joint studies, with more emphasis on total compensation, total benefits as a percentage of cash compensation, and the distribution (not only averages) of total compensation among firms.

5. Operating Expenses

5.1 Escalation of Costs

As ordered in D.89-12-052,[6] Edison developed its requested operating expenses based on recorded data through 1988. In all discussions in this chapter, expenses are stated in 1988 dollars unless otherwise noted. Test year 1992 revenue requirements will later be determined using adopted escalation rates and appropriate franchise fees and uncollectibles factors.

Edison and DRA, the only parties submitting testimony on escalation rates, agreed that the most recent data available should be used to determine test year expense levels. There is no dispute over methods for calculating the escalation rates.

During update hearings, Edison revised its estimates of escalation rates, lowering the rates from its original testimony. DRA agreed to the figures, which we will adopt. The escalation rates are shown in Appendix C to this decision.

6 Conclusion of Law 1, at mimeo., p. 11.

5.2 Controllable and Uncontrollable Expenses

We will separate operations and maintenance (O&M) costs into controllable and uncontrollable expenses. The distinction is broad and is made for accounting and forecasting purposes, not to pass judgment on which O&M items are absolutely controllable or uncontrollable through utility efforts.

Edison testified that it has generally achieved its Cost Containment goals through 1990, but five cost categories are exempt from that conclusion: (1) fuel-related costs, (2) DSM, (3) RD&D, (4) franchise fees, and (5) uncollectibles.[7] DRA would omit uncollectibles from this list, and add pensions and benefits, including health care, and property and liability insurance. We agree with Edison's characterization, amended to allow for special treatment of employee health care costs, which are growing faster than other expense elements, and postage.

5.3 Productivity and Cost Containment

DRA did not offer testimony on productivity, but adjusted A&G expenses downward to reflect the successes of Edison's Cost Containment program, which is a five-year effort begun in 1988 and aimed at increasing productivity. The program goal is to limit the growth of all O&M expenses to inflation less 1.5%. DRA's Cost Containment adjustment factor of 0.9435 is the ratio of (1.025/1.04), raised to the fourth power to reflect four years of savings from 1988 to 1992. According to DRA, this accounts for 1.5% incremental productivity, assuming 4% average inflation.

Edison responded to DRA's adjustment by immediately backing away from its own Cost Containment goals, claiming that the real rate of 1.5% is a goal, not a predictor of A&G expenses. We reject this attempt to shrink from realistic goals. Edison has

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7 Edison witness Thomas Noonan, Tr. 15:1069.

testified that despite obstacles the Cost Containment program is on track.

Edison further opposed expense adjustments for Cost Containment, arguing that: (1) DRA witnesses have treated Cost Containment adjustments inconsistently, (2) adjustment for Cost Containment in advance of achievements sends a negative signal to other utilities considering such a program, and (3) Cost Containment accomplishments are already included in historical trends. We agree that the coordination of DRA's A&G adjustments can be confusing, but we will not sweep away all Cost Containment savings for that reason. We focus instead upon the second of Edison's arguments, that depriving a utility of savings from cost containment is a disincentive to control costs in the long run. We agree, and consistent with our emphasis on incentives as a stimulus to increase efficiency in production, we adopt a shared approach. Edison has gained 1.5% per year in cost containment savings. We will allot .75% of that savings to ratepayers and .75% to shareholders, which amounts to a revenue reduction of $37.4 million for the test year, as displayed in Appendix C. We must include forecasts of utility cost containment, or we would guarantee that early program achievements will always accrue to shareholders, not ratepayers. Splitting the savings retains the incentives while balancing fairness to ratepayers who should receive annual savings from expected prudent management practices. Concerning Cost Containment results within trends, we will apply savings as goals are set -- overall, not account by account.

We agree with Edison's argument that historical productivity achievements are included in data trends. Our preferred method to realize the adjustment for cost control is by broad application, rather than account by account reckoning. Determining what Cost Containment goals are achieved for each account is at odds with Edison's broad brush approach to its own Cost Containment program. Further, such minute examination account by account is impractical. Ideally, the Commission could review Edison's Cost Containment accomplishments for every FERC account, determine the most reasonable approach and apply test year adjustments as appropriate. Realistically, this is impossible. Variability in function by function Cost Containment targets are not known. Therefore, for ratemaking purposes we must assign one half of the Cost Containment gains to test year expenses in the same broad way that productivity is measured and Cost Containment goals are established. We will adjust all labor, nonlabor, and other expenses for Cost Containment achievements, according to the following table:

TABLE 2

Productivity and Cost Containment Adjustments

Adjusted in Test Year	Not Adjusted
Production expenses	Fuel-related costs, not in GRC
Transmission expenses	Postage
Distribution expenses	Uncollectibles
Customer accounts, except postage	Health care benefits
	Franchise fees
A&G, except health care benefits	RD&D
	DSM

We realize that elements of some O&M accounts are uncontrollable or are based on trends that include productivity, but we must apply productivity adjustments uniformly in order to ensure that overall accomplishments are properly reflected in Edison's rates. This is fair to Edison because account-by-account exclusions of productivity adjustments would require higher than average productivity adjustments for the remaining accounts. Productivity measurements and Cost Containment goals apply to all controllable O&M accounts. With some reasonable exceptions, our productivity and Cost Containment adjustments will apply to the same accounts.

We find that sharing productivity expense adjustments between shareholders and the ratepayers to reflect Cost Containment is reasonable and necessary. We will adopt reasonable values for Cost Containment gains. The 1.5% savings attributed to Cost Containment is amply supported by the record. First, Edison is meeting its Cost Containment goals, including health care, and should continue to do so. Recorded A&G expenses for 1987 and 1988 indicate Cost Containment achievements far exceeding 1.5%, net of inflation. Second, 1.5% savings for Cost Containment is consistent with a June 12, 1991 statement from chief executive officer John Bryson to Edison employees, in which Bryson announced 1992 expense increases of 2.2%, excluding health care. Using the adopted 1992 escalation factors in Appendix C and 1.5% for Cost Containment, Edison's net expense increase would be 2.0%, very close to Bryson's target.[8]

We will adopt 1.5% as a reasonable level for real Cost Containment savings and will allot .75% of those gains to the ratepayers.

Allotting 50% of the stated Cost Containment adjustments to ratepayers will reduce Edison's revenue requirement by $37.4 million as displayed in Appendix C, in 1992 dollars. Sharing the Cost Containment savings between ratepayers and shareholders will provide a solid incentive to Edison to continue to vigorously pursue cost control goals. This treatment is supported by the record and $37.4 million should be passed through to ratepayers.

8 The composite inflation measure for 4.16% labor and 2.91% nonlabor is 3.56%, weighted by labor-nonlabor ratios requested by Edison for A&G expenses (Exhibit 172, page VI-28). Then, $(1 + 0.0356) \times (1 - 0.015) = 1.020$, a 2.0% increase.

In summary, we will estimate expenses in each controllable O&M account by assuming .75% Cost Containment savings. Other adjustments will be made where they are justified by DRA, Federal Executive Agencies (FEA), or Toward Utility Rate Normalization (TURN).

In its comments to the ALJ's Proposed Decision, Edison suggested that the adopted escalation rates include Cost Containment. The evidence does not substantiate that claim. The adopted labor escalation factors are based on labor rates negotiated between Edison and its unions, and on forecasts of the Consumer Price Index for Urban Consumers, as published by Data Resources, Inc. Edison's nonlabor escalation rates are derived from composite price indexes (for material, contract, and other expenses) and an overall measure of inflation for the U.S. economy. These factors are all measures of price growth, not growth of Edison's aggregate costs, and they do not include the impacts of Cost Containment. Our allocation of 50% of the Cost Containment achievement to the ratepayers is therefore not double counted as demonstrated by the record.

Edison's testimony on total factor productivity (TFP) indicates a range of 1.3% to 1.9% for annual productivity gains from 1976 to 1992. Edison also cites declining O&M costs (in constant dollars) per delivered kWh from 1986 to 1992. Edison suggests that no expense adjustments for historical productivity are warranted, and we agree. We accept Edison's rationale that historical TFP is already factored into Edison's revenue request for the test year, notwithstanding our observations that Edison did not clearly delineate these gains in their application. We note that in the Commission's recent Pacific Gas and Electric general rate case we also addressed the need for a showing by the utility which clearly demonstrates that historical productivity gains are included in the test year forecast. We will order the same thorough showing by Edison that we ordered two years ago for PG&E:

> "We will ask PG&E to present another multifactor productivity analysis in its next general rate case, and as part of the analysis, that PG&E demonstrate how the forecasted multi-factor productivity gains are reflected in its test year revenue requirement request." (D.89-12-057, Section III F)

Consistent with our order in that case, we will order Edison to conduct such a TFP study in its next general rate case.

Edison's testimony on total factor productivity (TFP) indicates a range of 1.3% to 1.9% for annual productivity gains from 1976 to 1992.[9] Edison also cites declining O&M costs (in constant dollars) per delivered kWh from 1986 to 1992. Edison suggests that no expense adjustments for productivity are warranted.

In its next GRC Edison should improve its showing on historical total factor productivity, to include not only overall measurements of productivity, but also the influence of historical productivity on expense forecasts for specific operating functions or accounts. The Cost Containment program demonstrates that Edison takes productivity seriously in its operations, and that concern should now be clearly identified in ratemaking forecast.

5.4 Production Expenses

All production expenses are subject to adjustments for Cost Containment. In this section we consider specific adjustments to non-nuclear production expenses and nuclear production expenses in general.

5.4.1 Conventional Steam Production

In its direct testimony, DRA recommended four expense adjustments. Edison stipulated to one, a reduction of expenses by $1.285 million for O&M at Edison's Cool Water Coal Gasification

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9 Exhibit 87.

Demonstration Plant.[10] Three disputes remain: an engineering assessment program, a protective painting program, and sale of Yuma Axis Generating Station, discussed elsewhere in this chapter.

5.4.1.1 Engineering Assessment Program

In 1990, Edison established an engineering assessment program (EAP) to maintain or improve thermal efficiency, availability, and reliability of Edison's conventional oil and gas generating plants. The need for this new program arose because the performance of aging plants deteriorates in time. Many of Edison's plant units are now more than 25 years old. The degraded performance is accelerated by the conversion of older plants from base load to intermediate or load following status. This increased plant cycling is caused by more base load plants coming onto the system, including new Edison-owned units and increased QF capacity. Plant cycling degrades performance due to increased thermal stresses.

The EAP identifies and plans for future corrective work, not necessarily to improve plant performance, but to prevent further deterioration. The test year budget for the EAP is $1.353 million. Edison has not quantified program savings, but believes that future savings (avoided costs) will be large.

DRA does not dispute that the EAP is cost effective, but recommends a reduction in O&M expenses to assure that program benefits accrue to ratepayers. In the absence of savings estimates, DRA would impute savings by reduction in allowable expenses equal to the cost of the program. DRA allocated the imputed savings to Federal Energy Regulatory Commission (FERC) Accounts 511, 512, and 513.

In response to DRA, Edison argues that test year O&M expenses should not be reduced, because program savings will occur

10 Tr. 10:471.

beyond the test year and in areas not reviewed in the GRC. The EAP will not extend plant life, but will improve unit availability and efficiency, and thus reduce fuel-related costs. As Edison witness Lawrence Hamlin testified:[11]

> "Q. So in assessing the costs and benefits of the engineering assessment program, the costs are being sought in this proceeding but the benefits to the ratepayers in terms of improved availability and heat rate will be handled in Edison's ECAC proceeding rather than this one?
>
> "A. That is correct."

We agree with Edison that base rate O&M accounts are the wrong place to assign ratepayer benefits from the EAP. Edison's Annual Energy Rate (AER) is now suspended, so test year benefits should flow to ratepayers through the ECAC account.

However, in emphasizing recovery of benefits DRA has strayed from the more important issue of the reasonableness of EAP expenses. We do not dispute that aging power plants deteriorate, but Edison has not demonstrated a concurrent need for increased funding. Plant deterioration did not arrive suddenly in 1990. Prudent managers should have operated and maintained the plant units in the ratepayers' best interests continuously, even prior to 1990. According to Edison's own testimony, Accounts 511, 512, and 513 show no statistically significant expense trends from 1983 through 1988. Should we believe that increased productivity and other factors have allowed Edison to increase maintainance of its generating units without increased overall production costs, or are ratepayers paying for failure to adequately maintain plant units, through increased fuel expenses? If the former is true, then there is no demonstrated need for new program costs. If the latter is

11 Tr. 51:5120.

true, then Edison has imprudently neglected ratepayer interests by allowing the plants to run down.

We expect Edison to go forward with the EAP, but within the conventional forecast of production expenses. Extraordinary expenses are not necessary. We will not allow recovery of the added $1.353 million in rates.

5.4.1.2 Protective Painting Program

Edison requested $138,000 annually throughout this GRC cycle for a new protective painting program. Edison argues that increased painting requirements due to aging facilities require the program. The coating systems that Edison plans to use will allow a longer duration between paint jobs, particularly in the coastal environment.

Again, DRA agrees that the program is reasonable, but recommends reducing Edison's requested production expenses by $138,000 to assure that ratepayers receive proper credit for the cost savings generated by the program.

We will deny approval of the increased program costs, for the same reasons that we deny increased costs for the EAP. We expect Edison to go forward with the new painting program, but it has not shown a need for increased production expenses. The trends for Accounts 511, 512, and 513 do not indicate a need for further expenses, and Edison has offered no evidence that increased painting needs will arrive suddenly in 1992.

5.4.2 Hydroelectric Production

Edison and DRA have a small dispute over hydroelectric O&M, relating to removal of certain timber and land management expenses associated with nonutility property at Edison's Shaver Lake facility. Both parties agree that an adjustment is necessary. The dispute, in the amount of $54,000, is over calculation of the adjustment. Edison believes that 15% of the timber maintenance expense should be removed, based on a 1987 study which shows that 85% of supervisory time was spent on utility property. DRA believes that 89% of the expense should be removed, because only 11% of the timber acreage is utility property.

Although the evidence on both sides is sparse, the amount in dispute is small. We find that Edison's study of supervisory time is a more reliable measure of actual expenses than timber acreage. We deny DRA's recommended adjustment.

5.4.3 Nuclear Production

Edison operates and owns 76.7%[12] of the San Onofre Nuclear Generating Station (SONGS), a three-unit plant near San Clemente, California. San Diego Gas & Electric Company (SDG&E) owns 20% of each unit. Various municipalities own small shares of SONGS 2 and 3. Edison also has a 15.8% ownership share of Palo Verde Nuclear Generating Station (Palo Verde) in Arizona. Palo Verde is operated by Arizona Public Service Company (APS). Edison and DRA disagree on reasonable methods for estimating production expenses at the two plants. Edison seeks approval of $226.1 million in expenses; DRA recommends $11.3 million less.

The record evidence presents the Commission with two extraordinary reasons to carefully protect ratepayers in adopting nuclear production expenses. First, no party presented "zero-based" budget testimony on O&M expenses for Palo Verde. There are good reasons for this, but estimation by comparison of O&M needs at Palo Verde with recorded or budgeted expenses at other plants makes Palo Verde expense estimates uncertain. Second, and more alarming, the evidence shows that Edison is not managing its SONGS units in ratepayers' best interests.

Edison witness Douglas McFarlane testified that PG&E has an incentive to reduce refueling outage durations at its Diablo Canyon Nuclear Power Plant (Diablo Canyon) as much as possible, to

12 80% of Unit 1, and 75.05% of Units 2 and 3, unweighted for investment cost or capacity.

maximize capacity factor. That incentive, which results in direct benefits to shareholders, has worked to shorten refueling outages at Diablo Canyon and "far outweighs" any additional costs to shorten refueling outages. A similar incentive would work for Edison.[13] The witness further testified that in planning refueling outages, Edison considers the target capacity factor incentive in its tariffs, by which shareholders and ratepayers share the system benefits of high achieved capacity factor (once a minimum capacity factor is reached). However, absent target capacity factor impacts, Edison does not generally consider the balancing of refueling O&M costs against replacement power costs when it plans refueling outages. Edison's budgeting process restrains the funds available to do refueling outage work. If more money were available, outage durations could be reduced, but Edison does not compare replacement power benefits against refueling O&M costs.[14] We suspect that this occurs because Edison's shareholders would not receive the benefits. This causes us great concern. This concern leads us to scrutinize nuclear O&M expenses especially carefully, and to order Edison to file, in its current ECAC reasonableness reviews, additional testimony on: (1) incremental base rate O&M costs of shortening refueling outages, and (2) incremental replacement power costs associated with extending refueling outages. The testimony should cover all actual refueling outages during the review periods, and it should be served in accordance with a schedule ordered by the assigned ALJ in that proceeding. DRA should have the opportunity to serve responsive testimony.

13 Tr. 12:728.

14 Tr. 50:5007-5011.

Although Edison's witness was the bearer of these facts, we have no evidence that McFarlane, who is manager of Budgets and Administration for Edison's nuclear organization, has developed or is responsible for the management practices.

In Edison's last GRC, the Commission ordered Edison to make a comparison study to establish a zone of reasonableness for nuclear O&M expenses.[15] Edison has complied with this directive and recommends that a zone of reasonableness be defined as the average annual O&M expense for a comparison group, plus or minus one standard deviation for the data set. Edison presents data for several comparison groups--all nuclear plant units in the United States, pressurized water reactors (PWRs) larger than 400 megawatts electric (MWe), and, by segregation of the data presented, PWRs larger than 800 MWe. The O&M expenses can be presented as annual cost per unit or annual cost per installed MWe. For PWRs, the recommended zone of reasonableness can be chosen from the table below:

TABLE 3
Comparison Group Nuclear O&M Expenses
(1988 $)

Annual O&M Costs	Installed Capacity >400 MWe	Installed Capacity >800 MWe
Cost per unit ($ million):		
Average	$58.9	$63.7
Standard deviation	23.6	22.1
Coeff. of variation	0.40	0.35
Cost per kW ($):		
Average	$69.16	$67.11
Standard deviation	27.58	24.14
Coeff. of variation	0.40	0.36

Data source: Exhibit 11, p. 5-IIA-17.

15 D.87-12-066, Ordering Paragraph 24; 26 Cal. PUC 2d 392, 614 (1987).

We will not adopt a specific zone to assess O&M expense reasonableness, but we will compare recommended and adopted expenses against these values. DRA recommends that Edison perform another zone of reasonableness study in its next GRC. We concur and will order such a study.

Edison recommends that the Commission retain the present "flexible refueling outage schedule," which permits Edison to estimate attrition year refueling outage expenses in the event the number of outages in the attrition year differs from the number in the test year. No party protests this request. For the past several years, adjustments for varying outage schedules have been effective in estimating attrition year expenses. We will continue authorization of flexible refueling outage schedules.

5.4.3.1 SONGS

In its prepared testimony, Edison estimated test year expenses by first averaging recorded data for all SONGS O&M expenses in 1987 and 1988. It then applied a 2% per year real growth rate (despite data showing a 3% historical trend) and labor and nonlabor escalation factors to calculate a 1992 subtotal. Then incremental Nuclear Regulatory Commission (NRC) fees were added to reflect federal legislation in late 1990 which increased 1991 user fee funding to 100% of the NRC budget. Edison claims that its request is within the zone of reasonableness.

In response to DRA's testimony Edison adjusted its request, agreeing to: (1) add 1989 data to its two base years, because the proposed merger with SDG&E had no impact on nuclear O&M expenses, (2) exclude NRC fees from base expenses before applying the 2% real growth factor, and (3) separate overall O&M expenses into base costs and refueling costs, consistent with DRA's treatment and conventional attrition year expense estimation.

DRA recommended dividing nuclear O&M costs into base and refueling portions. DRA agrees with Edison's estimate of base O&M for SONGS, accepting Edison's 2% annual real growth rate and

Edison's estimate of $147.259 million for base O&M. DRA does not agree that the same escalation scheme should apply to refueling expenses. Instead, DRA recommends a "dollars-per-day" method, by which recorded data for refueling O&M expenses per day of outage are escalated forward to the test year, then multiplied by forecast outage days to determine test year expenses. DRA's refueling outage expense estimate is $2.955 million lower than Edison's requested $23.359 million. Edison vigorously opposed DRA's dollars-per-day calculation of refueling outage costs.

DRA also recommended a $152,000 reduction to Edison's requested $6.171 million for incremental NRC fees, to remove Edison's 2% growth factor. DRA believes the 1991 fee level will not be increased by the federal government. DRA also claims that its recommended O&M expense level is within Edison's zone of reasonableness.

We agree with DRA on the split of nuclear O&M expense into base and refueling portions. The separation of functions is useful and consistent with the attrition mechanism. We also agree with use of three years (1987, 1988, and 1989) of recorded data as a foundation for O&M expenses. We will authorize 1992 expenses based on the three years of data, escalated to reflect general inflation and include Edison's 2% real growth rate. The evidence shows that O&M costs at other plants generally exceed this rate, but we apply of the 2% growth factor because Edison's request is generally in line with the results of its industry comparison study which indicate higher than average real growth in O&M expenses. We approve this increase in nuclear O&M expenses reluctantly because we believe that the results of Edison's industry study are mediocre. For example, although the results of the comparison study overall show nuclear O&M expenses increasing, many plants in the comparison group show declining expenses. Nevertheless, the record provides us with no better basis than the comparison group study on which to judge increases in these expenses.

We are not convinced that expense trends based on an industry comparison group of nuclear facilities, whose operatons do not fall under our scrutiny, should form the basis for approval of increases in nuclear O&M expenses for Edison. Further, in light of our findings on Edison's management of refueling outages, we are generally concerned about Edison's management of its nuclear O&M budget. We are not, however in a position to adjust nuclear O&M expenses based upon our refueling findings. At this time, the issues of nuclear O&M and the management of refueling outages will be addressed separately.

We will revisit refueling in Edison's next GRC, where we expect an affirmative demonstration by Edison that it manages its refueling outages cost-effectively from a ratepayer, not shareholder, perspective. That showing should develop optimum refueling durations and should show exactly how incremental outage costs and replacement fuel costs depend on outage duration.

We reject DRA's dollars-per-day proposal for refueling costs. The exact dependence of costs on outage days is not known. Edison's testimony on outage days and refueling costs is conflicting. To authorize base O&M and refueling O&M expense, we will escalate forward the 1987-1989 recorded expenses, then split the total into base and refueling O&M using the ratios from Edison's requested amounts.[16]

The third element of nuclear O&M expenses is incremental NRC fees ordered by the federal government. The exact assignment of NRC costs to U.S. utilities is not on the record in this proceeding. We will authorize incremental expenses based on a $465 million national budget, divided by the 111 nuclear units that Edison cites, times the three units at SONGS, less the NRC fees embedded in Edison's recorded data (escalated to 1991). We will

16 Exhibit 172, page IV-7.

include neither 2% real growth nor nonlabor escalation from 1991 to 1992 in adopted NRC fees.

The total adopted nuclear O&M expenses (Edison share) for SONGS are $184.488 million (in 1988 dollars), as calculated by the Commission Advisory and Compliance Division (CACD). This equates to $77.8 million per unit per year and $87.6 per kW per year (total plant). These values are within Edison's proposed zones of reasonableness in Table 3. For attrition purposes, this estimate assumes that two units at SONGS will be refueled during 1992.

5.4.3.2 Palo Verde

Edison was unable to estimate test year O&M expenses at Palo Verde using historical data because the data is limited and Palo Verde O&M expenses are unstable. Nor could Edison compute a "zero-based" budget due to instability of expenses and difficulty in analysis of plant records. (Edison does not operate Palo Verde.) Instead Edison chose to estimate Palo Verde expenses by scaling of expenses recorded or forecast for SONGS. DRA generally agreed with comparison against SONGS but disputed Edison's scaling techniques.

Edison proposed a scaling factor, or ratio of Palo Verde to SONGS expenses, of 1.28, before adjustments for NRC fees and a water treatment facility (WTF) unique to Palo Verde. The scaling factor is the ratio of numbers of certain active equipment (valves, pumps, and instruments) at the two plants, reduced by 15% based on professional judgment, to reflect increased productivity at Palo Verde. The scaling factor stems from the logic that O&M expenses depend largely on the numbers of plant equipment that require regular maintenance. Passive equipment, such as cables and piping, is excluded.

After applying its scaling factor, Edison added costs for increased NRC fees and the WTF. Edison testified that the WTF does not offset any other O&M functions. Edison stated that its requested expense level for Palo Verde is within its zone of reasonableness.

DRA used different scaling factors to estimate Palo Verde expenses from SONGS expenses. DRA's base O&M factor is 1.1309, the ratio of 1988 expenses at Palo Verde to the average of 1987, 1988, and 1989 expenses at SONGS. DRA computed a separate factor of 1.1312 for refueling costs. DRA believes that its ratios are reasonable because achieved capacity factors and numbers of refueling outages at both plants were similar, and WTF operation was normal in 1988. Edison opposed DRA's scaling factor, arguing that Palo Verde's short operating history makes such comparisons unreasonable.

DRA again estimated refueling expense using its dollars-per-day approach and adjusted NRC fees to exclude Edison's 2% real growth factor. DRA included WTF costs in its estimate, but opposed Edison's WTF adjustments to the comparison group data, arguing that the comparison data include extraordinary and unusual expenses at other plants. DRA claims that its total estimate for Palo Verde O&M expenses is within the zone of reasonableness.

We agree with Edison that zero-based budgeting is impractical, and use of a scaling factor is appropriate until stable operating data are available. We have already rejected DRA's dollars-per-day approach. The key issue remaining is choice of scaling factor. Although Edison's approach is intuitively appealing, it is untested as a predictor of O&M expenses. There is simply no evidence of proven correlation between equipment counts and O&M costs. DRA's scaling factor relies on a single year of data at Palo Verde, but the 1988 recorded expenses include first year expenses at Unit 3, and Edison's own experience at SONGS shows that first year O&M may be more costly than in later years. This would increase the scaling factor, favoring Edison. We will adopt DRA's method, revising it only to use a scaling factor of 1.131 for both base O&M and refueling O&M costs.

Finally, we must consider adjustments for real growth rate, NRC fees, and WTF costs. We will exclude Edison's 2% real adjustment, because Edison has not shown that APS effectively manages its refueling outages. The scaling factor will be applied to SONGS adopted 1992 expenses. We expect Edison to present in its next GRC testimony on the plant operator's efforts to optimize refueling outages, as we ordered Edison to analyze operations at SONGS. We will base Palo Verde NRC fees on the 1991 federal budget, without escalation or real growth, as was done for SONGS. We will include WTF costs, despite the inclusion of extraordinary costs in comparison group data, as long as the final expenses are within a zone of reasonableness.

The adopted O&M expenses (Edison share) for Palo Verde are $42.726 million, or $87.5 million per unit per year and $67.1 per kW per year (total plant). These values are within the zones of reasonableness in Table 3.

5.4.3.3 Other Issues

SDG&E requested that the Commission approve Edison's nuclear O&M expenses for purposes of adopting SDG&E's nuclear O&M expenses in SDG&E's next GRC. The Commission has done this in the past to avoid repetitious litigation. No party opposed SDG&E's proposal, and we will approve it.

TURN argues that Edison's rates which include SONGS 1 O&M expenses should be authorized subject to refund, because the operating status of the unit is uncertain. Fuel Cycle 11 is now scheduled to end in late 1992 or early 1993. In this GRC Edison requested approval of capital additions necessary to operate SONGS 1 beyond fuel cycle 11, but the issue has been removed to another proceeding.[17] We will grant TURN's request. SONGS 1 base O&M expenses comprise 34.02% of all SONGS base O&M expenses

17 D.91-03-058.

(excluding NRC fees) in the 1987-1989 data set. The refueling O&M fraction for SONGS 1 depends on whether the unit is refueled that year. Test year NRC fees are $3.251 million. These figures should be used to calculate SONGS 1 O&M expenses if they are eventually excluded from Edison's rates.

5.4.4 Yuma Axis

Edison has filed A.90-08-014 with the Commission requesting authority to sell its Yuma Axis Generating Station (Yuma Axis) to the Imperial Irrigation District. The Commission has not yet reached a decision on the application. Edison included $785,000 in associated O&M expenses in its GRC request, $749,000 for steam production and $36,000 for other production.

DRA believes that the O&M expenses should be removed because Edison plans to execute the sale when it is approved, and the California Energy Commission's (CEC's) 1990 Electricity Report (ER90) does not include Yuma Axis in Edison's resource plan. DRA and Edison agreed that any action related to the O&M expenses associated with Yuma Axis should depend on the outcome of A.90-08-014.

Edison answered that if the sale is approved by the Commission and the date of transfer of ownership is known in time to incorporate into this decision, Edison would agree with the DRA's proposed expense reduction. However, until the Commission acts on A.90-08-014, DRA's recommendation is premature.

We cannot now predict when A.90-08-014 will be decided. We will leave Yuma Axis O&M expenses in Edison's rates for now, but order that the ALBRR be reduced on the effective date of the sale. An associated rate change is not necessary.

TURN noted that the exact amount of the O&M expense is uncertain. Edison and DRA have agreed on a figure of $785,000 in 1988 dollars, but in Exhibit 16 an Edison document shows $960,000 (apparently in 1992 dollars) for Yuma Axis O&M expenses. These figures are inconsistent. The $960,000 in Exhibit 16 equates to

$834,000 in 1988 dollars using the adopted escalation rates in Appendix C. We note that if the $66,000 of transmission O&M attributable to Yuma Axis is included, the total is $851,000, much closer to the O&M total shown in Exhibit 16. This figure should be refined in A.90-08-014.

5.5 Transmission Expenses

Edison's estimate for transmission O&M expenses is $71.618 million. DRA recommended a $1.031 million reduction to that amount. No other party has submitted testimony on these expenses. DRA's recommended expense reductions appear in three areas.

5.5.1 Sylmar Converter Station

The Sylmar Converter Station is jointly owned by Edison and the Los Angeles Department of Water and Power (LADWP), which operates and maintains the facility, and bills Edison monthly for its 50% share of expenses. In May 1989 the owners completed a major expansion project, increasing station capacity by 55%. Edison has increased its transmission O&M expense request to reflect the expansion, estimating a 50% increase in O&M costs at the station (the station capacity increase, less 10%). The increase is limited to four of the 14 FERC accounts used to book transmission O&M expenses.

DRA estimated additional expense for the expanded facility by comparing the average of monthly billings 16 months before and 20 months after the new facility went into commercial operation. DRA assumed that the $305,000 difference in annual costs between those two periods is the best measure of increased expense for the new facility. DRA believes that prorating expenses to station capacity is unreasonable because new technology reduces the number of valves that are required, the new facilities take up less land area than the older facilities, and modern equipment may require less maintenance than equipment in the existing facility. Edison opposed DRA's recommended adjustment, arguing that 20 months of recorded data subsequent to commercial operation is too little and too early in the life of a modern facility to be used to predict future O&M expenses.

Edison has not shown that converter station capacity accurately predicts O&M expenses. We agree with Edison that O&M expenses in the initial years of a new facility may not indicate long-term O&M trends, but in the short term covered by this GRC cycle recorded data for 20 months will better forecast test year expenses than Edison's simple but heroic assumption about the relationship between station capacity and O&M costs. We accept DRA's adjustment of $305,000.

5.5.2 Estimation Method

DRA recommended that Edison's requested O&M expenses be reduced by $660,000. The reduction is supported by DRA's more detailed estimation method. Edison trended, averaged, and adjusted its past expenses as they are recorded in 14 FERC accounts. DRA went through a similar exercise but analyzed 214 functional accounts within the same FERC accounts. DRA then collected its results into the FERC accounts. Edison argued that DRA's method leads to anomalous results, in part because scrutiny of accounting data at the functional account level introduces increased variability in the individual data trends. As a demonstration of this, Edison points out that: (1) in four of the 14 FERC accounts DRA recommends expenses higher than Edison's own requests, and (2) revised utility practices might confuse functional account trends, for example contracting for work previously done by utility staff. DRA responded by arguing that its more thorough analysis allows more detailed adjustments for nonroutine historical expenses, and that Edison's approach is overly broad. DRA testimony cited adjustments for nonroutine expenses in the areas of: (1) training programs in 1986 and 1987, (2) reduced painting of transmission towers after 1989, and (3) reduced transmission plant additions after 1989. None of these changes is mentioned in Edison's testimony.

DRA's net $660,000 adjustment comprises subtotals of $2.118 million of reductions in ten accounts and $1.458 million of increases in the remaining four accounts. TURN did not offer testimony on this dispute, but argued in its opening brief that the Commission should not authorize more than Edison's requested amounts in any single FERC account. TURN cites the testimony of Edison witness Frank Haroldson, who stated that for each FERC account Edison's test year estimate is reasonable.[18] Edison opposes TURN's position, characterizing DRA's recommendation as a single net adjustment of $660,000.

We agree with TURN's argument, supported by Edison's testimony, that it would be unreasonable to authorize transmission O&M expenses higher than Edison's request in any single account. At the same time, we are impressed that DRA has analyzed each functional account in detail. We accept DRA's premise that adjustments for nonroutine recorded costs are appropriate. We are thus confronted with DRA recommendations for $2.118 million in expense reductions in ten FERC accounts. We must strike a balance between Edison's claim about increased data dispersion, which has merit, and DRA's impressive and more thorough review of past expenses.

Because both Edison and DRA make valid arguments, we will split the difference and reduce Edison's requested expenses by $1.059 million. In the next GRC we encourage DRA to again study Edison's functional accounts in detail, but the resulting adjustments can be applied directly to FERC account trends and averages, avoiding unnecessary data variability.

18 Tr. 10:518-519.

We recognize that the adopted expense reduction exceeds DRA's recommendation. This is entirely reasonable. The use of historical expense trends implicitly validates past utility practices which receive only brief review by the Commission and are not subject to rigorous reasonable reviews. The use of trends is an imperfect technique for authorization of the minimum expenses necessary to provide safe, reliable service.

5.5.3 Yuma Axis

In addition to $785,000 of production expenses, Edison requests $66,000 in transmission O&M expenses for Yuma Axis. DRA recommends removal of these expenses. We will treat Yuma Axis production and transmission O&M expenses consistently, allowing them in rates, subject to refund in the event the proposed sale of the plant is completed during this GRC cycle.

5.6 Distribution Expenses

During hearings Edison conceded expense reductions of $217,000 in response to DRA recommendations. Three disputes remain, two with DRA and one with FEA.

5.6.1 Supervision and Engineering

FERC Accounts 580 and 590 record electric distribution supervision and engineering costs. Charges to the accounts are, in part, overheads allocated from clearing accounts for projects that require supervision and engineering. Edison used 1988 recorded amounts as a basis for test year expenses. DRA used various averaging schemes for the 50 functional accounts within Account 580 and the 14 functional accounts within Account 590. DRA auditors adjusted 1987 and 1988 recorded data to remove $2.390 million in nonrecurring expenses for inspection of underground facilities. DRA recommended that Edison's requested test year expenses be reduced by $1.406 million. Edison opposes the reduction, arguing that DRA's method is defective and that the auditor's adjustments incorrectly assume that underground inspection is a nonrecurring activity. Edison testified on rebuttal that the underground inspection program, which began in 1987, is a continuing maintenance program.

We are convinced by Edison's testimony that underground inspection is ongoing. We reject the adjustments by DRA auditors. The trends from which the auditors' $2.390 million are subtracted cover seven years of data. Thus, we deny $341,000 of DRA's recommended reduction, leaving $1.065 million in dispute. As with transmission expenses, we must balance DRA's thorough review of distribution functional accounts against Edison's methodological objections. Splitting the difference, we will reduce Edison's requested expenses for distribution O&M by $532,000.

5.6.2 Storm Damage

DRA recommended increasing Edison's estimates for uncollectible damage claims and storm damage by a net of $76,000, the sum of a $145,000 increase to Account 583 (apparently including the impacts of a $1.694 million reduction in claims over the years 1982 to 1988, recommended by DRA auditors) and a $69,000 reduction to Account 598. We will authorize only Edison's requested amounts for Account 583, consistent with our treatment of the four transmission O&M accounts for which DRA recommended expense increases.

Edison estimated Account 598 expenses using a five-year average of accrued estimates for distribution property damage, arguing that differences between estimates and actual expenses will average out in the long run. DRA compiled recorded amounts of damage "for 1982 through 1980 [sic] and averaged the same five-year period."[19] Although recorded costs are more accurate than accrued estimates, Edison apparently relies on more recent data. We will again split the difference, reducing expenses by $35,000.

19 Exhibit 205, page 6-12.

FEA also disputed Account 598 expenses, but for different reasons. FEA recommended reducing Edison's request by $1.490 million, escalated to $1.769 million in 1992 dollars. Edison averaged five years of data from 1984 to 1988, and FEA used five years from 1986 to 1990. Edison opposes FEA's proposal, claiming that because the FEA has used updated data selectively, its method is unfair and inconsistent with the use of recorded data only through 1988 as directed in D.89-12-052.

We accept FEA's use of more recent data for averaging purposes, but to avoid the possibility of unfair database selection, we will expand the base period and use recorded data from 1984 to 1990. We adopt a seven-year average expense level, which is $1.205 million lower than Edison's request. This reduction does not duplicate the $35,000 reduction in response to DRA's argument.

5.7 Customer Accounts Expenses

Edison requested $110.163 million for Accounts 901, 902, 903, and 905, an amount 9.10% higher than recorded expenses in 1988. This compares well with the adopted increase in customers of 9.56%. With the exception of postage expense and uncollectibles methods, no party opposes Edison's request.

Account 901 expenses for supervision will increase at a higher than average rate, but Edison explains this as due to transfer of functions from Account 903, which shows a lower than average increase. Excepting the issue of postage expense within Account 903, we accept Edison's uncontested estimates for Accounts 901, 902, 903, and 905.

5.7.1 Postage Expense

Postage is recorded in FERC Account 903 under "other" expense, meaning that it is not subject to routine labor and nonlabor escalation in attrition years. Edison, DRA, and FEA testified to postage costs. DRA recommends a $658,000 reduction from Edison's requested $15.183 million. FEA recommends that no more than $14.663 million be authorized.

As FEA's testimony demonstrates,[20] postage expense is determined by: (1) average annual number of customers, (2) number of mailings per customer, (3) the distribution of mailings among the four types of first class, bulk mail service that Edison intends to use, and (4) adopted postage rates for each service.

We will use the adopted number of 4,136,224 customers (from Appendix B to this decision) for postage calculations. The parties contested the number of mailings. Edison initially used 14.75 mailings per customer, the recorded average for 1985 through 1989, but later revised its figure to 15.34 mailings, from 1990 records. Edison cites increased "Urgent Notices" to delinquent ratepayers, induced by recent residential rate increases, to justify the higher figure. FEA and DRA recommend the original five-year average because there were fewer mailings in 1989 than in 1990 despite the initiation of Urgent Notices in 1989. We will use all the data available and adopt a six-year average of 14.85 mailings.

FEA criticized Edison for failing to pursue less expensive mail service where it is available, but FEA included in its testimony Edison's distribution of mailings among the four services used. The services are: Carrier Sort (59%), ZIPsort (28%), Presort (10%), and ZIP+4 (3%). Edison's distribution is adopted.

Edison assumed that test year average rates for the same four services will be $0.2300, $ 0.2480, $0.2583, and $0.2420 per piece, respectively. These are the U.S. Postal Service rates effective February 3, 1991, except for Presort service, which is the $0.2480 rate plus an average fee of $0.0103 paid to a mail

20 Exhibit 424, Schedule 13.

service contractor. The contractor aggregates mail from different senders in order to qualify for bulk rates. Neither FEA nor DRA contest these rates. We adopt the requested postal rates. If rates change, Edison can pursue revenue requirement changes in attrition proceedings. The adopted postage expense is $14.633 million, in 1992 dollars.

5.7.2 Uncollectibles

The second customer accounts dispute concerns uncollectibles. Edison and DRA both forecast an uncollectibles factor of 0.208%, but they disagree on the method to arrive at this figure. Edison's estimate is based on a simple five-year average of 1984 through 1988 data. DRA used a five-year average of 1986 through 1990 data, adjusted for anticipated test year savings from Edison's participation in the California Utility Exchange, which is the successor to Enercom, an independent company that maintains data on uncollectible utility accounts.

Despite agreement with DRA on the uncollectibles rate, which is the only figure that materially affects customer rates, Edison in its opening brief continued to debate methods. Edison did not explain why further Commission action is necessary. We adopt the 0.208% uncollectibles rate and decline to split hairs over methods.

5.8 Administrative and General Expenses

A&G expenses are those O&M expenses which are not to charged to a specific functional activity. In general, A&G expenses are the costs of operating and maintaining Edison's central office and district offices, along with companywide insurance costs, advertising, and other items. The forecasting techniques for A&G expenses are as varied as their functions. Our words from Edison's last GRC decision apply equally well now: "Again, we find ourselves in the dilemma of determining a reasonable level of A&G expense.[21] The contested issues are found in testimony by Edison, DRA, FEA, and TURN.

We will inspect A&G accounts individually, paying special attention to the influence of productivity. We have previously discussed Edison's Cost Containment program, which adds to ongoing levels of historical productivity. Specific adjustments will be made where they are justified by DRA, FEA, or TURN.

5.8.1 Customer Growth

In Edison's last GRC the Commission capped A&G expense increases for forecast growth in numbers of customers. Edison now argues that application of a customer growth factor to controllable A&G expenses has been "endorsed" by the Commission, and Edison's A&G cost estimates are based on customer growth.

DRA opposed Edison's estimation method, arguing that tying A&G costs to customer growth in D.87-12-066 was a temporary measure until Edison could improve its estimation techniques in this GRC. According to DRA, Edison has ignored Commission instructions by estimating A&G expenses based on customer growth. DRA further argues that the relationship between A&G expenses and customer growth is very weak, citing a correlation study by DRA witness Cleason Willis.

The evidence clearly favors DRA's position. DRA's testimony shows that for A&G expenses from 1982 through 1988, customer growth can explain only 57.9% of the variation in the data. Edison responded that for data from 1982 through 1986, prior to the Cost Containment plan, the correlation (expressed as r-squared in a conventional linear regression) is 98%.

Our own correlation studies, using DRA's data for 1982 through 1988, show that the year that the expense was incurred is a better predictor of A&G costs than customer growth (71.0% correlation vs. 57.9% for customer growth). Regression analysis of

21 D.87-12-066; 26 Cal. PUC 2d 391, 421 (1987).

only 1982 through 1986 data against the year of the expense again improves the correlation, compared to regression against customer growth. Finally, correlation does not demonstrate causality. It is possible that, although customer numbers and A&G expenses are both growing, other factors are responsible for the increases. We can only conclude that the connection between A&G expenses and customer growth is flimsy. We will deny increases in A&G expenses related to customer growth unless further connection can be shown.

5.8.2 Account 920 - Administrative and General Salaries

No party objected to Edison's use of 1988 as a base year for A&G salaries. Recorded expenses in 1988 were $118.982 million, the sum of costs in 16 functional categories. To determine test year expenses we will make accounting adjustments for merger and holding company expenses and for double counting of executive bonuses, subtract unnecessary costs, and escalate the remaining necessary costs forward to 1992. Escalation will include ordinary inflation and productivity and Cost Containment savings, but will exclude customer growth.

5.8.2.1 Executive Bonus Accruals

Edison pays Executive Incentive Compensation awards (bonuses) in the year following the year of performance. In 1988 Edison changed its accounting procedures for bonuses from a cash basis to an accrual basis. Differences between accruals, which are now booked at 85% of the maximum amounts, and amounts actually paid are eventually booked to the account. Thus 1988 recorded Account 920 expenses included bonuses earned in 1987 but paid in 1988, and bonuses accrued in 1988 but paid in 1989. The record does not reveal what adjustments were later made to the 1988 accruals. Edison admitted that 1988 recorded expenses should be adjusted to remove the double counting of bonuses. Edison removed $1.7 million, the cash bonuses earned in 1987. TURN recommended removing $2.2 million, the amount accrued for 1988 bonuses. We adopt TURN's adjustment because it better reflects actual 1988 bonus payments. Edison's accrual covers 1988 obligations, but the amount is arbitrary until adjustments for actual bonus payments are made.

5.8.2.2 Executive Chauffeurs

Edison employs four full-time executive chauffeurs who also perform security functions. The security duties allow Edison to deduct the costs of the drivers for income tax purposes, rather than show the costs as taxable income for the four executives. The four passengers are the Chairman of the Board, the President, the past Chairman of the Board, and the past Executive Vice President of operations. DRA recommended a disallowance of $144,000 for the drivers, because Edison has not shown a need for chauffeurs or bodyguards.

We will allow the expenses for the active employees, the Chairman of the Board and the President, in hopes that the driver services will contribute to productivity. We will remove from 1988 expenses the costs for past officers. Their drivers are unnecessary executive perquisites.

5.8.2.3 Unexplained Cost Increases

TURN recommended removal of $309,000 from 1988 Account 920 costs, arguing that a 39.5% increase in corporate communications--one of the 16 functional areas in the account--from 1987 to 1988 is not justified. During cross-examination, Edison's witness did not know the reason for the increase. Edison claims that adjustments to functional accounts are unwarranted when the FERC account costs as a whole are used to estimate test year expenses. Other functional accounts show decreases from 1987 to 1988.

Inspection of the 16 functional accounts shows that 1987 to 1988 increases exceeded 10% in three areas: corporate communications, executive officers, and power supply. We agree with TURN that it is reasonable to exclude unexplained functional cost increases within Account 920, but we must choose an appropriate threshold for reasonableness. TURN suggests using 3.2%, the customer growth rate from 1987 to 1988, even though TURN does not endorse calculation of A&G costs based on customer growth rates. We will adopt a different threshold, equal to double the average growth rate of controllable A&G expenses from 1982 through 1988. This threshold, determined by linear regression of expense data, is 7.3%.[22]

We will reduce 1988 expenses for corporate communications by $275,000, the difference between the $1.178 million recorded in 1988 and 7.3% above the $842,000 recorded in 1987 (in 1988 $).

TURN also recommended a reduction of $792,000 in 1988 costs for executive officers, because Edison has not justified the 19.3% increase in that area from 1987 to 1988. We deny this adjustment because the 1988 recorded amount of $5.866 million will be reduced by $2.2 million for double counting of executive bonuses, moving the base amount below the reasonableness threshold.

Edison's functional account for power supply shows an increase of 17.8% from 1987 to 1988. This is above the threshold but is justified by increased costs for management of QF contracts. No adjustment is necessary.

5.8.2.4 Executive Bonuses

In Account 920, Edison has included $1.814 million for executive bonuses, the portion of executive compensation tied to annual performance. DRA recommended removal of these expenses from 1988 recorded data, because: (1) bonus plans are aimed at corporate goals and objectives "only remotely related to improving or maintaining the quality of service to ratepayers," (2) removal is consistent with the Commission's denial of a management incentive plan for PG&E, and (3) in response to a DRA data request, Edison refused to provide details on the performance ratings of individual executives.

22 Regression analysis shows average A&G growth of $6.928 million per year, using data from Exhibit 205, Table 9C - 3. This growth rate, divided by 1988 expenses, is 3.65%. See also Exhibit 29, Account 920, Workpaper 0020.

DRA also cited documents prepared for a CACD workshop on management bonuses. Edison objected to use of workshop documents which were intended to be confidential outside the workshop. The ALJ did not receive the documents into evidence, and we will not rely on them now.

TURN supported disallowance of executive bonuses, arguing that the bonus plan should be self-funded out of the benefits that flow from the plan.

Edison vigorously opposed DRA's position, arguing that: (1) executive bonuses are widely used in industry and are necessary to attract and retain capable executives, (2) DRA misinterpreted Commission policy on use of management incentives, (3) total compensation (salary, bonuses, and benefits) is difficult to compare among companies, and (4) DRA's own wage and salary study shows that Edison's executive cash compensation (salary and bonuses, excluding benefits) is below average compensation levels for major electric utilities.

We confirm the position announced in PG&E's GRC that there is a place for executive bonuses in utility management. If we were to reject the bonuses, Edison might require higher executive salaries to offset the lost bonuses. Our principal concern is adoption of necessary expenses for provision of safe, reliable service at reasonable, nondiscriminatory rates. We distinguish this GRC from PG&E's GRC. In D.89-12-057[23] we endorsed the concept of management incentives, but we denied funding a broad-based program that would have increased PG&E's expenses above a reasonable company-wide A&G expense level. In this case we must decide whether past expenses were necessary, and whether to adjust base data for purposes of escalation into the test year. We reject DRA's argument that its adjustment of

23 34 Cal. PUC 2d 199, 254-260 (1987).

historical data is consistent with rejection of a new program in D.89-12-057.

We give little weight to evidence on the rank of Edison's cash compensation among other corporations, utility or nonutility. Comprehensive comparisons are simply not on the record, despite our instructions in Edison's last GRC.[24] The most notable omission from measures of executive compensation is noncash benefits. DRA testified that total compensation comparisons are difficult, but Edison witness Carl Jacobs was more optimistic.

We are left with two issues: (1) the goals of the bonus plan, and (2) DRA's discovery problem. Edison's executives are obliged to pursue the long-term goals of both shareholders and ratepayers. Which are served by executive bonuses? For the answer, we turn to the performance measures used in carrying out the bonus program, specifically the testimony of Edison witness Noonan.[25] The record evidence shows that: (1) Edison uses two fundamental measures to assess executive performance, one related to company performance and one related to individual performance; (2) company financial measures are general, not specific, and are based on the judgment of the Board of Directors; (3) other company measures include Cost Containment results, service quality, and organizational effectiveness; (4) service quality measures include customer growth, cost per new customer, and customer response time, but there are no set standards; (5) it is uncertain whether service reliability or public safety are included as service measures; and (6) reasonableness of rates and perceived rate discrimination are not included as bonus measures.

Edison does not separate shareholder and ratepayer goals, claiming that the various bonus plan measures all produce benefits for both shareholders and ratepayers. Although we disagree with

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24 26 Cal. PUC 2d 392,457 (1987).

25 Tr. 15:1136-1146.

DRA's characterization that bonus plan goals are unrelated to ratepayer benefits, we also disagree with Edison's grand claim that what is good for shareholders is also good for ratepayers. Separation of bonus plan goals is difficult, but we are struck by the lack of company measures directed specifically at ratepayer benefits. In this respect, Edison's bonus plan is similar to PG&E's plan, for which we stated that benefits are "overwhelmingly weighted in favor of shareholders."[26] We find that: (1) bonus plan measures do not provide adequate incentives for safe, reliable service at reasonable, nondiscriminatory rates; (2) reliance on Board of Directors' judgment and absence of specific standards diminish the fairness and effectiveness of executive bonuses; and (3) the need for and effectiveness of the bonus plan are obscured by lack of rigorous program assessment and failure to provide DRA with measurements of individual performance.

Considering these factors, we find that only one-third of Edison's executive incentive payments were necessary in 1988. This is a judgment, but a judgment required by the circumstances of the dispute before us. We will remove $1.210 million from 1988 expenses before escalating recorded amounts forward to the test year. We remind Edison that we are not disallowing the plan or denying the effectiveness of executive incentives. Rather, we are assigning to shareholders the expenses that Edison's executives use to pursue shareholders' goals and objectives.

5.8.2.5 Rate Recovery of WMBE Expenses

DRA recommended excluding from A&G expenses $556,000, which Edison requested for its Women and Minority Business Enterprises (WMBE) program. This is the recorded 1988 WMBE amount, comprising $346,000 in Account 920 and $210,000 in Account 921 expenses. Edison requested that the 1988 amount be escalated to the test year, without incremental expenses for increased program

26 D.89-12-057; 34 Cal. PUC 2d 199, 159 (1989).

scope. DRA supported its position by citing D.89-08-026, in which the Commission ordered that WMBE programs shall be considered in annual generic proceedings which address policies, practices, procedures, and costs for all respondent utilities. Edison opposed DRA's recommendation, because the anticipated generic proceeding, which would have considered 1992 expenses, was never opened. This leaves Edison without a forum for recovery of 1992 expenses. Edison payments to a WMBE information clearinghouse are protected by a memorandum account authorized in Resolution E-3133, approved on March 22, 1989.

We agree with Edison that it should have the opportunity to recover reasonable 1992 WMBE expenses. The issues are when and how much. Edison requested forecast test year recovery of escalated expenses from 1988. The record evidence on the reasonableness of the $556,000 in 1988 recorded costs is skimpy, but much of that amount was direct payments to the Commission-approved clearinghouse, over which Edison has little control. We also accept that clearinghouse payments are increasing as more businesses qualify for WMBE status. This information is adequate to justify the test year amount. We will grant Edison's request, but with the reminder that Edison will have no further opportunity to recover 1992 WMBE costs in other proceedings.

The anticipated generic proceeding should eventually be opened in time to address 1993 costs. We intend that attrition year 1993 and 1994 WMBE expenses will be superseded by orders in the generic proceedings. We will terminate expense entries into Edison's clearinghouse memorandum account. Further debits are unnecessary under forecast test year ratemaking.

5.8.2.6 Summary

After reduction for: (1) executive bonus accrual, (2) executive chauffeurs, (3) unjustified corporate communications costs, and (4) unjustified executive bonuses, the adjusted Account 920 expense in 1988 dollars is $116.220 million. This amount will be escalated to an adopted expense level for 1992.

5.8.3 Account 921 - Office Supplies and Expenses

The first of two disputes concerning Account 921 is the $210,000 in WMBE expenses recorded in this account. The issue was resolved above, and no adjustment to recorded 1988 costs is necessary. Escalation to test year expenses will be the same as escalation for Account 920. Second, in its testimony TURN listed $615,000 in A&G expenses related to Edison's holding company activities.[27] Edison agreed to exclude the expenses from revenue requirement. During hearings TURN identified an additional $67,000 for the printing of stock certificates. That amount has been removed from authorized Account 921 expenses.

5.8.4 Account 922 - Construction Overheads

Edison accumulates capital costs for construction projects in project work orders. Included in construction costs are overheads for administration, in this instance A&G labor and nonlabor costs charged to Accounts 920 and 921, respectively. As these overheads are assigned to construction they must be removed from A&G accounts, which is done by crediting Account 922.

DRA and FEA disputed the percentage that Edison used to credit the transferred overhead. Edison uses 17%, based on an "effort study" of 1990 organizational budgets. Edison claimed that 17% is lower than historical rates due to reduced construction activity. DRA and FEA recommended 20%, based on the average of recorded percentages from 1982 through 1988.

The evidence shows that transfer rates were in the 22% to 24% range in 1982 and 1983, then stabilized around 20% from 1984 to 1988. We will adopt a transfer rate of 19.78%, the historical average for the five stable years from 1984 through 1988. For ratemaking purposes, Account 922 credits will be forecast at the adopted transfer rate times adopted Account 920 and 921 expenses.

27 Exhibit 418, Attachment A.

We are sympathetic to Edison's argument that construction is declining, but the evidence on net plant additions and overall A&G trends does not support Edison's lower rate of 17%. The effort study, which is not in evidence, was apparently based on budgets, not actual accruals.

5.8.5 Account 923 - Outside Services

Edison based its requested expenses for outside services on the average of recorded costs for three years from 1986 through 1988, adjusted to remove merger-related costs. Edison excluded data from years prior to 1986 due to exceptionally high legal costs for antitrust proceedings.

DRA accepted the three-year average for base costs, but recommended a Cost Containment reduction. TURN recommended a $422,000 reduction for unexplained increases in engineering costs, similar to its reduction for corporate communications in Account 920.

We will adopt the three-year average for base costs, reduce that amount for Cost Containment, and escalate forward to the test year. We reject TURN's adjustment. Account 923 overall expenses are based on multiyear averages which do not show a long-term increasing trend, unlike Account 920 expenses, which are based on a single year of data within an increasing trend. The three-year base amount (in real dollars) for Account 923 is about 10% higher than costs prior to the three-year base period. This increase is tolerable within a relatively stable FERC account.

5.8.6 Account 924 - Property Insurance

The majority of Account 924 costs are insurance premiums, which Edison estimated based on brokers' advice, trade publication information, and Edison's own judgment. Premiums requested for 1992 are about 1% lower than 1988 premiums, in real dollars. Edison's test year requests for labor and nonlabor property insurance costs are escalated values of 1988 recorded costs, adjusted for customer growth.

DRA accepted Edison's premium costs estimates, but recommended that $118,000 in crime insurance premiums be removed from test year expenses, because no claims were made from 1988 through 1990 and it is unlikely that Edison will ever experience crime loss exceeding the crime policy deductible amount. The policy coverage is $20 million with $500,000 deductible.

Edison responded that the insurance is reasonable to cover losses due to theft, robbery, computer and wire fraud, and bonding requirements for tax-deductible employee benefit plans. Edison argues that recent claims history is not indicative of risks and potential lawsuits.

The ratio of coverage to annual premiums shows that the disputed crime insurance is intended to cover small probabilities of high losses, which are exactly the risks that short-term claims history cannot measure and which insurance should cover. Where claims trends are stable, self insurance might be more reasonable, but crime insurance does not fall into this category. We deny DRA's adjustment.

DRA also recommended a reduction of $29,000 to update Edison's five-year average cost of insurance reserves. We will make that adjustment.

Along with conventional liability and property insurance, Edison purchases replacement generation insurance for its SONGS and Palo Verde nuclear plants. Annual premiums are about $1.4 million for SONGS (76.7% ownership share) and about $0.8 million for Palo Verde (15.8% share). We will allow these expenses, but in its next GRC Edison should justify the disparity in premiums for the two plants. We note that replacement generation expenses are now borne completely by ratepayers. Therefore, in the event a claim is ever pursued under these insurance policies, insurance awards should be returned to ratepayers through credits to the ECAC account.

5.8.7 Account 925 - Injuries and Damages

Edison's test year estimates for Account 925 were developed using the same techniques that were used for Account 924.

DRA again accepted Edison's estimates of insurance premium costs, but DRA opposed Edison's calculation of insurance reserves expenses. In compiling historical data, Edison used reserve amounts set at the time claims were filed, which would often be reduced by the time payments were actually made. DRA requested supporting workpapers, but Edison had discarded the information. DRA calculated reserves based on actual payouts and recommended a $4.460 million reduction in reserve costs. Edison conceded the adjustment.

5.8.8 Account 926.1 - Health Care Benefits

Edison's health care costs can be conveniently split into administration costs (labor and nonlabor), externally purchased services (health care providers, health maintenance organizations, dental plans, and vision plans), and post-retirement benefits other than pensions (PBOPs).

5.8.8.1 Administration and Purchased Services

Edison estimated administrative costs based on a 1989 base year, because in 1989 the company made significant changes to the health care programs under its control. (Health care costs were actually lower in 1989 than in 1988, a result which we commend.) Edison then escalated labor and nonlabor costs forward to the test year, including adjustment for customer growth. Edison estimated purchased services costs based on health care inflation trends, specific information from service providers, recommendations from an actuarial consultant, and management intentions toward use of the various health plans.

In its original testimony, DRA recommended a $22.890 million reduction in Account 926.1 costs, comprising $16.187 million to exclude PBOPs, a $7.903 million reduction for purchased services, and a $1.200 million increase for administration. DRA used later data than Edison used in deriving its expense recommendations. Edison reviewed DRA's later data and agreed to reduce its requested expenses by $6.753 million, resolving all disputes with DRA except rate recovery of PBOPs. Edison disagreed with DRA's exact split of expenses into cost categories, but agreed with DRA's overall costs for administration and purchased services.

We will adopt the agreed-upon expense level for purchased services, but we will adjust the stipulated administration costs to remove escalation related to customer growth from 1989 to 1992. DRA has elsewhere convinced us to exclude A&G costs related to customer growth, and Edison testified that the stipulated labor and nonlabor expenses include such growth. This adjustment amounts to a $1.123 million reduction in expenses and a $5.759 million reduction in capitalized benefits.

We are concerned that DRA has recommended an increase in administration costs over Edison's request, but in testifying to the stipulation Edison explained that the reduced purchased services costs will require extra administrative effort. We accept this explanation. No further reduction is necessary.

5.8.8.2 PBOPs

PBOPs are utility liabilities--principally medical benefits for employees, retirees, and their families--which have in past years been paid by utilities on a cash basis, without setting aside funds to cover future costs and without recognizing the liability on financial statements. In December 1990, following a comment period, the Financial Accounting Standards Board (FASB) adopted its Statement of Financial Accounting Standards No. 106, which revised the generally accepted accounting principles for PBOPs. Effective January 1, 1993, corporations must accrue PBOP liabilities while employees earn the benefits, not when the benefits are actually paid. Limited portions of PBOP funds are tax-deductible.

The Commission is investigating the impacts of this accounting change in I.90-07-037 and related matters. On July 2, 1991 the Commission approved D.91-07-006, which decided issues on pre-funding of PBOPs, in order to maximize the accumulation of tax-free funds before deciding whether full funding and recovery in rates of PBOP obligations is in the best interests of ratepayers. The Commission found that pre-funding of tax-deductible PBOPs is in the ratepayers' best interests. The decision authorized, but did not require, utilities to implement four types of tax-free PBOP funds: (1) an Internal Revenue Code (IRC) § 401(h) plan, (2) a Voluntary Employee Benefit Association (VEBA) plan, (3) a collectively bargained VEBA plan, or (4) a pension benefit enhancement plan for pre-funded tax deductible contributions. Utility-owned life insurance plans may not be used.

In this GRC Edison requested $12.6 million in rates to pre-fund PBOP liabilities in a § 401(h) plan which it established in December 1990. Edison argued that D.91-07-006 authorizes rate recovery of tax-deductible contributions, and a failure to pre-fund will result in a loss of tax-free earnings. The § 401(h) plan which Edison proposes does not cover all employees. Union members and certain key employees, a small number of managers, are excluded. Edison intends that union employees will be covered by VEBA plans. The relief requested in the GRC is for test year 1992 only. Edison has requested recovery of 1990 and 1991 PBOP contributions in Advice No. 913-E, filed August 15, 1991, and Advice No. 917-E, filed November 1, 1991. Edison requested 1993 and 1994 costs in A.91-08-066.

DRA's position changed during the course of Phase 1 in this GRC. In its testimony, DRA opposed rate recovery of PBOP costs, pending the outcome of I.90-07-037. In its opening brief, DRA acknowledged D.91-07-006 and conceded that Edison could recover PBOP costs once the evidentiary requirements ordered in D.91-07-006 are met. DRA's reply brief argued that Edison has overestimated the maximum amount that can be contributed to the § 401(h) plan, because Internal Revenue Service (IRS) regulations[28] set the limit for the sum of § 401(h) plan and life insurance costs combined. Edison has calculated the limit to be $16.2 million, but has not subtracted life insurance costs to determine maximum contributions to the § 401(h) plan. Therefore, rate recovery should be denied until a proper calculation is made. Edison testified that no deduction is required by the regulations.

FEA opposed recovery of PBOP costs in rates, claiming that D.91-07-006 authorizes recovery only in Edison's next GRC, and that Edison's proposal is unreasonable because it uses union pension contributions as the basis for pre-funding PBOP contributions made under a § 401(h) plan which explicitly excludes union employees. FEA argues that if pre-funding is approved, the amounts must be limited to 25% of total PBOP costs annually, rather than 25% in the aggregate since the § 401(h) plan was started, and that $4.3 million should be excluded because that amount is for past service credits, which are ineligible for funding under the IRC.

We concur with Edison's general intention to maximize its contributions to tax-exempt PBOP plans. D.91-07-006 found that pre-funding will reduce long-run costs and is in the ratepayers' best interests. However, making contributions and recovery in rates are two separate steps in the process. Ordering Paragraph 5 in D.91-07-006 clearly states that Edison can seek rate recovery of PBOP costs in its next GRC or as an increase in margin under the ERAM, and Edison's request in this GRC is for an increase in margin. D.91-07-006 anticipated the distinction between contributions and rate recovery by authorizing utility memorandum accounts for booking of costs in advance of rate recovery. We

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28 Internal Revenue Regulations, Section 1.401-14(c).

reject FEA's argument that D.91-07-006 precludes rate recovery in this GRC.

Edison has made efforts to comply with the funding and evidentiary requirements of D.91-07-006, but two issues remain relating to Ordering Paragraph 7, which requires in pertinent part that Edison's $ 401(h) plan be reasonable. First, as FEA points out, is it reasonable to use union pension costs to justify a plan from which union employees are excluded? Second, has Edison incorrectly calculated its maximum $ 401(h) contribution by failing to subtract life insurance costs?

The reasonableness of Edison's plan to use union employee benefits to justify contributions to the $ 401(h) plan has two elements: fairness to union employees, and possible overfunding of the $ 401(h) plan. Edison intends that PBOPs for union employees will be funded under VEBA plans, but it uses union employee PBOP liabilities to calculate contributions to the $ 401(h) plan. The VEBA plans are not complete and are the subject of collective bargaining. FEA hints that this is unfair to union workers, but we disagree. The Commission's duty is to authorize reasonable expenses for employee compensation as a whole, without micromanaging the distribution of employee salaries, wages, and benefits. Union employees should recognize that Edison's early adoption of a $ 401(h) plan may achieve certain tax savings that will not accrue to union members until the VEBAs are in place, but we will not substitute our judgment for the collective bargaining process on this issue.

Edison has testified that pre-funding is only a small part of its PBOP liability. Nonetheless, we are concerned that the $ 401(h) plan could become overfunded, relative to future PBOP obligations to unrepresented employees. This might happen if, for example, full PBOP funding is not eventually authorized in I.90-07-037 and the present contribution fraction--33% of annual liabilities under Edison's proposal--is higher than the fraction of

Edison's PBOP costs that are assigned to unrepresented employees. The record does not reveal the likelihood of overfunding for unrepresented employees. Nor is the record absolutely clear about reduced § 401(h) contributions due to life insurance costs.

For these reasons, we deny Edison's request for rate recovery in 1992 of 1992 PBOP liabilities. We encourage Edison to take advantage of tax-deductible PBOP plans, as long as plans for separate employee classes (union or unrepresented) are not overfunded, consistent with Ordering Paragraphs 4 and 5 of D.91-07-006. Edison should continue to record 1992 PBOP costs in a memorandum account, as authorized in D.91-07-006, until Edison's next GRC or further order in I.90-07-037.

5.8.9 Account 926.2 - Pensions and Other Benefits

Edison's overall expense request for pensions and benefits (exclusive of health care) in 1992 is $97.397 million, which is 15.51% above recorded expenses in 1988. This increase is very close to adopted escalation rates over the 1988 to 1992 time frame, but expense increases for the different elements of Account 926.2 vary markedly from the average. Edison splits its request into five major areas, one for administration and four for benefit plans: (1) administration, increased by 10.5% plus inflation from 1988 to 1992, (2) retirement, up 8.3% in nominal dollars, (3) Stock Savings Plan (SSP), up 28.0% in nominal dollars, (4) disability, up 27.5% in nominal dollars, and (5) life insurance, up 58.9% in nominal dollars. All of the purchased services are 26% capitalized by Edison, so any reductions will have expense and rate base components.

In 1989 Edison began a flexible plan called SCEflex, which allows full-time employees to spend utility-paid "flex dollars," choosing from various programs for health care, life insurance, disability, and tax protection of vacation payments. Retirement benefits are not included. We have no philosophical objection to SCEflex, but it does allow for offsetting of health care expenses against non-health care expenses, at the employee's election. In this GRC, Accounts 926.1 and 926.2 have been treated separately by Edison and the DRA. In future GRCs Edison should provide information on this shifting of benefits between the two accounts.

5.8.9.1 Administration

Edison's requested administration costs of $9.721 million were calculated using a 1988 base year, escalated to 1992 for both customer growth and inflation. DRA recommended a $2.549 million reduction, of which about $0.8 million is attributable to escalation based on employee growth rather than customer growth, and $1.75 million is unnecessary expenses for employee activities, administration of an employee club, a cafeteria, and other employee welfare expenses.

We will authorize test year expenses based on the undisputed 1988 base year, escalated for inflation only. We have previously rejected customer growth as a factor in forecasting A&G expenses. We must also reject DRA's reduction for employee-related expenses. DRA cited previous Commission decisions which excluded charitable contributions and expenses for a PG&E employee organization. Edison argued that the PG&E organization was dedicated to charitable, educational, and social activities, and that Edison's Account 926.2 request does not include expenses of the types previously disallowed. We are concerned that Edison's requested expenses might include unreasonable employee-related expenses, but DRA's showing in this area is conclusory and poorly supported by the record evidence.

5.8.9.2 Retirement Benefits

Edison based its requested retirement expenses on the recommendations of Foster Higgins, an actuarial consulting firm. Edison requested test year retirement expenses of $53.836 million (in 1992 dollars), after conceding a $184,000 adjustment recommended by DRA relating to the ERISA/IRC method for calculating pension costs. With that concession, there is no remaining dispute over the propriety of the ERISA/IRC method. It should be continued in the future. DRA has no further disputes with Edison over retirement costs.

FEA recommended that Edison's test year retirement costs be reduced by $2.250 million, $1.865 million in expenses and $0.655 million for the 26% capitalized share. FEA cited four reasons for the reduction: (1) use of 5.94% as the appropriate "normal cost rate," based on a downward trend of recorded data from 1986 through 1990, (2) reduction in the number of employees, based on recent recorded data, (3) an inflation error, and (4) unnecessary expenses for unfunded executive retirement plans. Edison first responded that the normal cost rate trend will not continue. Edison based its expense request on a rate of 6.14%, and an actuarial study introduced on rebuttal forecasted a 6.35% rate in 1991. Second, employee numbers will rise to forecast levels as vacancies held open in anticipation of the Edison-SDG&E merger are filled. Third, the inflation error is moot now that Edison has conceded a similar recommendation by DRA. Fourth, Edison has offered to further justify its executive retirement expenses to FEA under a suitable confidentiality agreement.

We will accept Edison's use of 6.14% for the normal cost rate. That 1988 rate is the lowest recorded rate in recent years, and Edison's rebuttal evidence successfully refutes use of a data trend in this instance. We will also accept Edison's explanation for recent reductions in the number of employees. Edison assumes zero growth in employees from 1988 to 1992. We reject FEA's claimed inflation error because it is inadequately explained. We adopt FEA's recommendation regarding executive retirement costs. Edison has not justified its claimed connection between executive retirement and labor costs. Edison's suggestion that executives are exempt from routine discovery requests further convinces us that Edison has not met its burden of proof.

5.8.9.3 Stock Savings Plan

Edison seeks \$21.673 million (in 1992 dollars) for its SSP, based on 1988 recorded expenses plus customer growth and labor inflation. DRA believes that 1988 expenses should be escalated for labor inflation and employee growth, rather than customer growth. Because Edison's employee growth rate is zero, DRA recommended a reduction of \$1.818 million from Edison's request. FEA also recommended rejecting escalation for customer growth, and further recommended a \$2.235 million reduction for reduced employee numbers.

We have previously dealt with customer growth and employee numbers. We will adopt test year expenses for the SSP based on a 1988 base year and adopted labor escalation rates. We deny FEA's adjustment for employee numbers. We will not find that SSP costs should be tied to numbers of employees, as DRA suggests, because the finding is unnecessary.

We note that Edison reports its SSP expenses as "other" costs in Account 926.2, a term generally applied to expenses that are not subject to labor or nonlabor escalation. Nonetheless, we will authorize labor escalation for the test year because of the obvious connection between the SSP and overall labor costs. Edison contributions to the SSP are based on percentages of employee salaries. Use of the "other" accounting category precludes attrition year increases for the SSP.

5.8.9.4 Disability

Edison requested recovery of \$7.795 million (in 1992 dollars) for disability, rehabilitation, and wage continuation benefits. The amount was derived by William M. Mercer, an employee benefits consulting firm, using Edison employee demographic data and Edison forecasts of labor escalation. DRA did not dispute Edison's request. FEA recommended a \$37,000 reduction based on employee numbers.

Once again, we deny FEA's recommendation because Edison has justified its employee figures. We will adopt Edison's request.

5.8.9.5 Life Insurance

Edison requested $4.372 million (in 1992 dollars) for its various utility-paid life insurance plans, based on projected labor escalation, insurance premium rates, and claims information from insurance companies. In 1989 Edison increased its minimum life insurance coverage from $5000 to $10,000. In 1992 Edison plans to raise the minimum coverage to the higher of $10,000 or one-half of the employee's annual salary. Employee elections under SCEflex can increase life insurance coverage.

DRA recommended a disallowance of $815,000, based on use of a five-year average of life insurance costs rather than the consultant's study. In support of the reduction, DRA cited Edison's favorable claims experience and decreasing premium costs. DRA argued that: (1) although $10,000 in coverage is necessary, the further increase to one-half of annual salary is not justified, (2) the increased coverage is not the result of union negotiations, and (3) averaging is reasonable for data that vary widely from year to year. Edison replied that the increased coverage compares well with other California energy utilities, DRA's analysis is flawed because it ignores implemented coverage changes, and the five-year average that DRA relied upon is only for one element of Edison's extensive life insurance program. Edison believes the status of union negotiations is irrelevant to life insurance expenses.

We will deny DRA's recommended disallowance. Edison's expanded life insurance coverage is consistent with coverage by other California utilities, and DRA's testimony inadequately supported its claim that a five-year average is superior to Edison's more comprehensive analysis.

DRA and FEA both recommended a $30,000 adjustment to exclude portions of travel accident insurance dedicated to pleasure travel by Edison managers. Edison's justification is that managers are on call even when they are not working. This insurance coverage is unnecessary, and we will exclude it. The $30,000 is split into $22,000 of expense and $8,000 capitalized.

FEA also recommended a $233,000 insurance cost reduction for executive estate and tax planning, a program which Edison began in 1990. FEA argued that this is an unnecessary expense for an executive perquisite. The program has no direct benefits for ratepayers and has been disallowed by other state regulatory commissions. Edison did not respond to FEA's testimony or argument. We agree with FEA and will reduce authorized costs by $233,000, split into $172,000 of expenses and $61,000 capitalized.

5.8.10 Account 927 - Franchise Fees

Edison and DRA have agreed on a franchise fee rate of 0.7877%, which is applied to the utility's overall revenue requirement in order to forecast franchise fees paid to the many communities in Edison's service territory. No party has objected to the stipulated rate, and we will adopt it.

5.8.11 Account 928 - Regulatory Expenses

Edison originally requested $2.950 million in regulatory expenses, based on a three-year average of recorded expenses from 1986 to 1988, without escalation for customer growth. Before the filing of DRA's testimony, Edison agreed to a $3000 reduction, due to accounting errors. DRA then recommended an additional $277,000 reduction, using 1988 as a base year instead of the three-year average for the power supply function within Account 928. DRA believes that 1986 and 1987 power supply expenses were unusually high due to hydroelectric plant relicensing proceedings. Prior to hearings, Edison conceded to DRA's reduction, bringing Edison's request for Account 928 down to $2.670 million.

TURN recommended a reduction of $177,000 from the 1988 recorded expenses, to mitigate a 14.8% increase in legal costs that year. TURN claims that Edison has not justified this increase, and calculates the reduction by the same technique used for corporate communications in Account 920. We agree that the increased legal costs are inadequately justified, especially since the number of regulatory proceedings was unusually low in 1988. However, TURN's test year reduction must be modified to reflect use of a three-year base period for Account 928--rather than the single year for Account 920--and to incorporate a reasonableness threshold of 7.3% above previous expenses, as was used for Account 920. The adopted test year expense reduction is $15,000.

5.8.12 Account 930.1 - General Advertising

Edison requested $820,000 for general advertising expenses, excluding financial and DSM advertising. From this amount, DRA recommended reductions of $621,000: (1) $248,000 for video tapes, brochures, films, and other materials for in-house use; (2) $284,000 for exhibits and displays for general company use; and (3) approximately $89,000 to exclude Edison's escalation for customer growth.

We have already denied all A&G expenses tied to customer growth. DRA argues that the tapes, exhibits, and other visual aids are not allowable advertising under the restrictions of D.86794,[29] and Edison's advertising costs per customer are higher than costs for other California utilities. Edison replied that the disputed advertising costs are for general company use and contain customer service and safety-related information.

Account 930.1 records utility expenses for institutional and general advertising. Allowable expenses were explicitly set forth in D.86794: financial advertising, safety messages, essential customer service information, and conservation advertising. Edison's testimony on Account 930.1 activities stresses customer booklets and brochures, customer services,

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29 81 Cal. PUC 49, 79 (1976).

customer bill inserts, and customer media communications. We will reduce 1988 recorded expenses by the $248,000 for in-house materials, because Edison has not shown that the materials are safety-related or are intended to reach customers and are essential under the D.86794 restrictions.

The $284,000 for exhibits and displays is more difficult to assess. Edison's "general company use" description allows for the possibility of customer services (e.g., brochures and office displays), but the safety function is uncertain. Edison argues that some of the materials are safety-related, but Edison's director of advertising told DRA witness Hy Min that no safety-related messages were included in Account 930.1. Based on our uncertainty that all materials for general company use will reach customers, and that safety-related expenses are included in Account 930.1, we will reduce the 1988 recorded expenses by one-fourth, or $71,000. This results in a test year reduction of the same amount, because Edison used 1988 as a single base year for Account 930.1 expenses.

5.8.13 Account 930.2 - Miscellaneous Expenses

Edison requested $58.922 million in test year expenses for Account 930.2, plus labor and nonlabor escalation. Edison used various estimation methods to determine individual cost elements, reflecting the diverse utility functions covered by the account. The functions include recovery of abandoned projects; RD&D; dues and memberships; contributions; bank fees; trustee activities; employee publications; directors' fees and expenses; and others.

In its original testimony, DRA recommended a reduction of $1.017 million in Account 930.2 expenses, to reinstate a credit that Edison had removed relating to non-utility charges. Edison pointed out that the same charges are now credited to Edison's ERAM account, in compliance with D.88-01-063.[30] DRA then withdrew its expense reduction and agreed to continuation of ERAM credits for these non-utility charges.

Table 4 below lists the expense reductions recommended by DRA, FEA, and TURN.

TABLE 4

ACCOUNT 930.2 ISSUES
(Thousands of 1988 Dollars)

Expense Reduction: Recommended	Expense Reduction: Adopted	Issue
		RD&D:
$ 8,789	$ 3,326	Customer energy technology
3,655		Customer air quality
183	183	Customer growth
(20)	0	Cost Containment
1,730	1,730	BiCEP abandonment
3,231	3,231	Minor abandoned projects
193	0	Aircraft expenses
337	0	Dues and donations
+ 878	+ 878	Directors' pensions
$18,976	$ 9,348	Subtotal, by DRA
46	35	EEI dues, by FEA
+ 62	+ 62	NMRC dues, by TURN
$19,084	$ 9,445	TOTAL

Disputed RD&D costs are considered elsewhere in this decision. We accept DRA's adjustment for customer growth, consistent with our adopted treatment of other A&G expenses. The remaining issues are discussed below.

5.8.13.1 Abandoned Projects

Edison requested $4.961 million in Account 930.2 expenses for recovery of the capital costs of abandoned projects, divided

30 27 Cal. PUC 2d 347 (1988).

into $1.730 million for the Big Creek Expansion Project (BiCEP) and $3.231 million for minor projects. DRA opposed rate recovery of the entire $4.961 million, on the grounds that the Commission does not permit recovery of plant costs from ratepayers unless the plant is used and useful, except in periods of great uncertainty. According to DRA, Edison's projects do not qualify for the exception. Edison claims there is evidence to support the uncertainty surrounding the BiCEP project, and recovery of small project costs is consistent with Commission precedent set in previous GRCs.

Edison intended that the BiCEP project would expand the Big Creek Hydroelectric Project by construction of new dams and reservoirs, and by addition of five turbine-generators at existing powerhouses. The project began in 1985 and was cancelled in October 1988, before Edison applied for a Certificate of Public Convenience and Necessity (CPCN). BiCEP project recorded costs in Edison's capital project accounts total $5.191 million, of which 96.8% was incurred in 1985, 1986, and 1987. Most of the costs were for project engineering and environmental work. None were for physical plant.

Edison cites three reasons for the project cancellation, all related to the availability of lower cost alternatives to the BiCEP project: (1) a change in assumptions by the CEC regarding the deferrability of spot purchases of capacity from other utilities, (2) increased available capacity from QFs, and (3) increased capacity acquisitions by Edison's resale cities customers. Edison now seeks to recover the costs by amortization of the $5.191 million over 3 years, without carrying costs or allowance for funds used during construction (AFUDC). The $3.231 million for minor projects is the five-year average of recorded abandonments from 1984 through 1988.

The general rule for abandoned projects is well settled. Utilities cannot recover the costs of plant that is not used and useful. The issue in this GRC is whether or not Edison's projects qualify for the exceptions previously announced by the Commission. In D.83-12-068[31] the Commission authorized PG&E to amortize $60.8 million in costs for 26 abandoned projects. The compelling facts in that application were: (1) the period during which many of the projects began was one of dramatic and unanticipated change, and (2) the financial impacts of the abandonments on PG&E were substantial. In D.84-05-100[32] the Commission allowed partial recovery of a 1973 PG&E project because it occurred in a "period of dramatic and unanticipated change.... The period was characterized by great uncertainty in the energy industry, both as to demand growth and availability of supply." In D.89-12-057 the Commission denied recovery of the costs of another PG&E project because the utility had not satisfied its burden of proof:[33]

> "PG&E has not shown (1) that the project ran its course during a period of unusual and protracted uncertainty, (2) that the project was reasonable throughout the project's duration in light of both the relative uncertainties that then existed and of the alternatives for meeting the service needs of the customers, (3) when the projects were cancelled, and (4) that they were cancelled promptly when the conditions warranted."

For the BiCEP project, Edison fails several of these standards. Edison has not shown that the BiCEP project ran its course during a period of unusual and protracted uncertainty. Although Edison did not accurately forecast the arrival of QF capacity and the departure of resale demand, there is no evidence that the years 1985 through 1987 were times of unusual uncertainty.

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31 In A.82-12-48; 14 Cal. PUC 2d 15, 50-52 (1983).

32 15 Cal. PUC 2d 123, 125 (1984).

33 34 Cal. PUC 2d 199, 269 (1989).

Also, Edison did not cancel the project promptly. According to Edison witness Ronald Maurel, Edison knew in May 1987 that QFs were coming at a faster than anticipated rate, but Edison did not cancel the project until 17 months later. Finally, the magnitude of Edison's request does not support granting an exception for the BiCEP project.

Concerning the aggregated minor projects, DRA argued that it is impossible for Edison to meet the standards of D.89-12-057 because reliance on historical data precludes identification of specific projects. We agree with DRA, and we reject Edison's argument about Commission precedent. Recovery of minor project costs may have been granted in prior GRCs,[34] but those approvals are not discussed in the relevant decisions and may not have been contested by the parties.

5.8.13.2 Aircraft Expenses

In this GRC, Edison originally requested A&G expenses for two corporate jet aircraft, a Cessna Citation and a Lockheed Jet Star. DRA auditors recommended excluding from Account 930.2 the expenses for both aircraft, and in the course of hearings Edison withdrew its expense request for the Jet Star. DRA still recommends a reduction of $193,000 in expenses for the Citation, arguing that commercial air travel would be more cost-effective than operation of the jet. According to DRA, the Citation averaged only 2.7 passengers per flight during DRA's review period, flew most frequently to cities with adequate commercial air service, was only once used to respond to an emergency, and was consistently more expensive than charter aircraft rates. DRA also cited

34 D.87-12-066 and D.84-12-068, Edison's two previous GRCs.

D.88-08-061,[35] in which the Commission denied executive jet expenses for General Telephone Company of California.

Although we are concerned that Edison should manage its travel expenses effectively, we will not adopt DRA's expense reduction. There is no evidence that Edison is using the Citation as an executive perquisite, and comparison of Citation costs against commercial and charter aircraft costs obscures the value of convenience and time saved for Edison's managers. Edison has conceded the costs of one jet aircraft. Allowing the Citation costs in rates seems reasonable from the record evidence.

<u>5.8.13.3 Dues and Donations</u>

In its testimony, DRA recommended a $724,000 expense reduction for dues, fees, and contributions to organizations which provide no quantifiable benefits to ratepayers. During hearings Edison withdrew $387,000 of its request, leaving $337,000 at issue. FEA contested an additional $46,000 in dues to the Edison Electric Institute (EEI), arguing that Edison's deduction of 14.01% of EEI dues attributable to political advocacy is too low. The appropriate figure should be 20.51%, excluding legislative policy research, institutional publications, and litigation costs. TURN recommended a $62,000 reduction for Edison's membership in the Nuclear Management and Resource Council (NMRC), which TURN characterized as an advocate for nuclear power. The recommendations by the three parties do not duplicate one another.

Edison responded that DRA's analysis is limited and arbitrary, and the disputed dues were allowed in previous GRCs. Edison replied to TURN by arguing that the purpose of the NMRC is not to promote nuclear power, but to inform members "on matters pertinent to nuclear power and nuclear energy development."

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35 29 Cal. PUC 2d 63, 77 (1988).

According to Edison, this information is of vital interest to ratepayers. Edison did not respond to FEA's allegation.

We deny DRA's expense adjustment. Edison's claimed precedent is weak, because the facts in previous GRCs may not match the facts in this GRC, but we agree that DRA's showing is conclusory, unsupported by the necessary facts. We agree in part with FEA. For ratemaking purposes we will increase the disallowed fraction of EEI dues from 14.01% to 19.45%, to exclude legislative policy research. The adopted reduction is $35,000. We will also adopt TURN's reduction of $62,000 for the NMRC. We reject Edison's conclusion that the NMRC's purpose excludes advocacy. The NMRC may say that it only provides information, but the evidence in this proceeding does not overcome our suspicion that the NMRC does encourage nuclear power.

<u>5.8.13.4 Directors' Pensions</u>

DRA recommended reducing Account 930.2 expenses by $878,000 for pension costs for outside members of SCEcorp's Board of Directors, and for directors' fees for time spent on holding company matters. DRA argued that directors are more like consultants than employees and should not receive pension benefits.

Edison responded to DRA's recommendation by presenting rebuttal testimony and by lengthy argument in its opening and reply briefs. Edison claimed that DRA has no standard for the reasonableness of directors' pensions, and that directors' pensions are recoverable because they are commonly used by other large corporations.

We will accept DRA's recommendation. In our judgment, Edison's evidence that large corporations commonly award pensions to directors does not demonstrate that the pensions are necessary. Outside directors work only part-time on SCEcorp's board, and only part of that effort is devoted to Edison. If the directors were regular employees of Edison they would not be eligible for pensions, and Edison has not proven the need for the pension expense.

5.8.14 Other A&G Accounts

Account 929 covers credits or charges for duplication of charges within utility operations. No charges of any consequence have been booked to this account since 1982, and Edison forecasts none for the test year.

Account 931 includes rents for offices and communications equipment space. Edison estimated test year expenses by examination of facility needs and anticipated lease costs. Edison's requested increase for rents is 13.0% over recorded 1988 costs, slightly less than the adopted nonlabor escalation rate. Rental expenses at Ontario and Chino airports will be reduced, as discussed in Chapter 6 herein.

Account 935 covers maintenance of general plant, including maintenance of communications equipment and certain accruals for uncollectibles and property damage. Edison's basis for test year labor and nonlabor costs is 1988 recorded data, escalated for customer growth. DRA opposed the customer growth escalation, and we will exclude it. Edison's request for "other" costs is based on five-year averages and is undisputed.

5.9. Taxes

There are no methodological disputes among the parties regarding calculation of income taxes. Dollar differences in income tax expense, payroll tax, and Superfund tax are driven by disputed levels of labor expenses, plant in service, revenues, etc. Both Edison and DRA recommend the use of the CACD's revenue requirement spreadsheet model to calculate adopted income taxes, after certain updating for recent tax law changes and Commission decisions.

Two disputes remain, regarding Edison's payment of Arizona property taxes for its ownership share of the Palo Verde nuclear plant.

5.9.1 Property Tax Litigation

Edison is a co-plaintiff in two lawsuits against Maricopa County, Arizona concerning claimed overassessments of property taxes. El Paso Electric Company vs. Maricopa County seeks judgment against the county for illegally calculating the 1987 primary property tax rate and levy limitation under Arizona law. The plaintiffs are the owners of the Palo Verde plant. Another matter, Arizona Public Service Company vs. Maricopa County, seeks judgment against the county for levying an additional tax too narrowly, specifically against mines and utilities. If Edison and its co-plaintiffs are successful in the latter lawsuit, then the amount of property taxes Edison has projected for 1992 would be reduced by $9.488 million.

Edison claimed that the outcome of Arizona Public Service Company vs. Maricopa County is speculative, and the Commission should include in Edison's 1992 revenue requirement the Arizona property taxes at the existing statutory rate. Edison stated that for ratemaking purposes, Edison's estimate is the best estimate available. DRA recommended that Edison establish a memorandum account to track the dollar impact of Edison's dispute with Maricopa County in the event the Commission later orders a refund. DRA would allow the existing tax obligation in rates, but subject to refund pending the outcome of the lawsuit. FEA recommended that the Commission exclude the disputed taxes from rates, and order Edison to book the costs as deferred debits in Account 186, pending eventual ratemaking treatment.

Although Edison's property tax calculation may be the best estimate available, it is too uncertain to be reasonable. Future test year ratemaking is effective only when reasonable expenses can be forecast, and the outcome of the lawsuit is too speculative for a reasonable forecast. We will adopt DRA's position and order a memorandum account to track all disputed Arizona property taxes, effective January 1, 1992. After the lawsuit is finally resolved, Edison should seek disposition of the memorandum account by advice filing. If Edison should prevail in the lawsuit, any property tax refunds should be returned to ratepayers.

5.9.2 Statutory Reduction of Property Value

In its testimony, FEA raised an issue concerning Arizona Revised Statute Section 42-144.02 (Section 42). This statute allows original plant in service to be reduced in value when a state or federal governmental order prohibits total or partial use of utility property for periods in excess of 6 months. FEA contended that this statute applies to the Palo Verde outages during 1989 and 1990, and the owners of Palo Verde should pursue recovery of improperly assessed property taxes. Edison testified that it reviewed the issue with its own property tax experts and concluded that pursuing a reduction in value would be fruitless.

The pertinent language of Section 42 reads:

> "The original plant in service cost shall be reduced by the reduction in value caused by a state or federal governmental order prohibiting total or partial physical use of utility property for periods in excess of six months."[36]

Edison has included in its testimony a letter from the Arizona Department of Revenue, in which the agency staff concluded that the Palo Verde outages do not meet the criteria in Section 42. According to the agency, the NRC actions which induced the outages are Confirmatory Action Letters (CALs) and are viewed as confirmations of voluntary actions, not orders. Edison also provided two legal opinions[37] which agree with the Arizona Department of Revenue. The distinction seems to turn on specific

36 Exhibit 59.

37 Reference item H.

language in NRC regulations which note that, "if a licensee fails to meet its CAL commitments, the NRC may issue an order to require the licensee to perform the actions committed to in the CAL."[38] An order making the CAL enforceable is missing.

FEA argues that these opinions hinge on whether the Palo Verde outages were voluntary or caused by a government order. According to FEA, Edison and its partners have been lax in not pursuing available tax relief. Edison should have pursued this issue further, either with the Arizona tax authorities or by seeking the necessary formal orders from the NRC.

Edison's rates for portions of the Palo Verde outages are now subject to refund, and Phase 3 of this proceeding is already set up to investigate the outages. We defer consideration of FEA's issue to Phase 3, on the record developed in Phase 1 or on an amended record as may be ordered by the assigned ALJ in Phase 3.

5.10 Information Services

In addition to its analysis of each A&G account, DRA reviewed Edison's information services budget for the test year. For 1992 Edison requested approval of $49.2 million in expenses and $10.1 million in capitalized software. Edison also requested approval for the 1992 capitalization of about $22 million in 1990 and 1991 software costs which exceeded Edison's authorized expense levels for those two years. Edison began capitalizing software in 1990. DRA opposed capitalization of software costs, and recommended that the Commission adopt a test year expense level of $49.2 million. According to DRA, the requested $10.1 million in capital costs will be offset by at least that much in benefits due to increased productivity, spread throughout Edison's A&G functions.

38 10 CFR Part 2, App. C, Section V.H.

Several issues present themselves. First, should Edison be allowed to capitalize its 1990 and 1991 expenses? Edison has argued that the requested capitalization is not double counting because recorded expenses exceeded authorized levels, and FERC rules allow for capitalization of software. We disagree. This change in accounting treatment for prior software expenses could constitute retroactive ratemaking, unfairly increasing ratepayer liability in future years to make up for Edison's inability or unwillingness to control expenditures in 1990 and 1991. We must be cautious before allowing Edison to make a second attempt at recovery of expenses that were already adopted on a future test year basis. We are concerned that this treatment would be unfair to ratepayers because they have no opportunity to reduce rate base in expense areas where Edison spent less than authorized, and Edison would lose the incentive to control its test year costs, an important feature of forecast test year ratemaking. If Edison did or intends to capitalize software in 1990 and 1991 for tax purposes, those capitalized amounts should be excluded from plant in service data for ratemaking purposes upon the effective date of this order.

Second, should Edison be allowed to capitalize any software costs incurred in 1992? Edison's arguments center on changing business conditions, apparent approval by the FERC, and acceptance of the practice within the utility industry. The FERC has not adopted regulations on capitalization of software, but a 1977 memorandum from the FERC Audits Division apparently allows the practice for "major new software involving relatively large expenditures for which benefits will be realized over several years."[39] This authority for capitalization may apply to Edison, depending on whether or not Edison's actual expenses in 1992 will

39 Exhibit 232, paragraph II.

be for major new software, but Edison has not supported the need for capitalization. Recitation of changing business conditions is not enough. Edison relies on survey data to support capitalization as an industry practice--29 of 51 survey respondents capitalize applications software--but that very survey questions the reasoning behind capitalization. As the survey report states, "A major omission of this questionnaire is why companies do or do not capitalize."[40] Edison claims that capitalization is better for ratepayers due to improved intertemporal equity, but the price is income taxes paid by ratepayers. Capitalization of A&G costs may also distort true capital costs of construction projects, if A&G expenses eligible for construction overheads through Account 922 would be reduced. In sum, Edison has not shown that capitalization of software costs will benefit ratepayers. Therefore we will not adopt capitalization treatment at this time.

This case has raised the question of whether ratepayers are better served to capitalize or expense information services. We note that the FERC has not promulgated guidelines for capitalization instead of expense treatment, and believe that established guidelines would be useful for this Commission and for the utility's ratepayers. In considering the nature of expenses, it would appear that software programs which are written and then replaced within a 3 year timeframe would most properly be expense items while software whose useful life exceeds 3 to 5 years may potentially be a depreciable asset. The record in this case for capitalization remains too unclear to authorize capital treatment of software at this time.

Edison may file therefore a more complete report and description of their preference to capitalize their software within

40 Exhibit 233, page 3.

120 days of the effective date of this order. Edison should serve all parties to this case with their report, if they so file. Parties to the case may file responses to Edison's report, if Edison chooses to so file, within 120 days of Edison's filing at the Commission. We reserve the latitude to revise our rules on capitalization of these software projects for ratemaking purposes at that time, and to promulgate succinct guidelines.

Third, should the Commission impute productivity benefits for Edison's increased expenses? The answer is yes, but not in the way that DRA recommends. Edison's information services expenses are growing at a rate that outstrips recent growth of Edison's sales, customers, or A&G budgets. This growth in excess of growth in corporate output suggests that an inherent goal of information services is increased productivity. The benefits flow to other utility departments. By themselves, rapidly growing information services are not necessary for the delivery of electricity, but they can improve utility efficiency.

Information services expenses increase productivity, but DRA's $10 million cost offset would unfairly double count productivity gains, duplicating the Cost Containment achievements that we have previously assigned in part to ratepayers. We will deny DRA's request.

Finally, what is a reasonable expense level for information services? Edison's requested $59.3 million exceeds 1988 recorded costs by 42.5% in real dollars. Even without the capital projects, the real expense increase is 18.3% above 1988 expenditures. We accept that information services are useful, but we are concerned about Edison's budgeting process. During DRA's review Edison could only offer preliminary information on the requested capital projects, because project identification occurs only late in the year prior to the budget year, after approval of the budgeted amounts. Edison's rebuttal testimony on software capital projects substantially amended the information relied upon by DRA in preparation of its testimony. Edison's budget committee approves budgets based on historical trends.[41] Although the rapid growth of information technology generally supports approval of Edison's expenses, it is impossible to justify the $10.1 million when the capital projects are not identified in time to assess costs and benefits. We will not reduce test year expenses by $10.1 million, as DRA recommended. Instead, we will authorize 1992 expenses equal to recorded 1990 expenses, in real dollars. Edison testified that expenses in 1991 will be unusually large, making 1990 a reasonable base year. De-escalating 1990 expenses back to 1988 dollars, authorized test year expenses are $54.693 million, which is $4.607 million less than requested by Edison. These amounts should be expensed, not capitalized. For ratemaking purposes, we will prorate the reduction over the nonlabor portions of A&G Accounts 921, 922, 923, and 924.

<u>5.11 Customer Service and Informational Expenses</u>

The FERC Uniform System of Accounts sets aside Accounts 907 through 910 for this function. Expenses are incurred in developing, implementing, and monitoring energy management programs. Edison's DSM programs are discussed in Chapter 11. The adopted DSM expenses are $140.860 million, excluding capital costs and shareholder incentives, which will be awarded in ensuing years.

<u>6. Rate Base</u>

Edison and DRA dispute several issues regarding plant in service and other elements of rate base.

<u>6.1 Plant in Service</u>

<u>6.1.1 Forecast and Recorded Plant</u>

In forecasting 1992 plant in service, Edison used recorded data through the end of the third quarter of 1990. DRA

41 Tr. 51:5083-5084.

was able to use recorded data through the end of 1990, which shows end-of-year plant in service $162.649 million lower than Edison's estimate. DRA recommended using the later information to forecast 1992 plant.

Edison opposed DRA's reduction, arguing that: (1) DRA should use Edison's cutoff date, because constant updating "creates havoc" in the ratemaking process, (2) DRA's minor plant decreases are offset by other, unidentified plant increases, (3) decreases in recorded plant may be offset by increases in forecast plant, as plant additions are deferred from the end of the recorded period (fourth quarter of 1990) to the forecast period (1991 and 1992), and (4) in D.85-03-042[42] the Commission in some way endorsed a policy to exclude updated data.

DRA argues that plant additions are deferred every year, and although budget information should not be revised to suit the occasion, recorded data should be used whenever it is available.

We agree with DRA on this point. Although recorded and forecast plant additions do interact, as Edison claims, Edison's analysis ignores the likelihood that deferral of plant at the beginning of a forecast period will be offset by the deferral of plant additions at the end of 1992. Deferral of plant additions is not symmetric. It is more likely that forecast plant additions will be completed late than early. This is typical of construction projects, and may even be influenced by the perverse utility incentive to delay actual construction of new plant once it is put into rate base. We will adopt DRA's $162.649 million plant reduction.

6.1.2 Yuma Axis

Consistent with its position on reducing production and transmission expenses for Yuma Axis, DRA recommended a coincident

42 17 Cal. PUC 2d 246, 254 (1985).

$18.330 million reduction in plant in service. If Yuma Axis is sold during this GRC cycle, Edison should remove the plant from rate base (at its depreciated book value at the time) and remove from the ALBRR both O&M and capital-related revenue requirements.

6.1.3 Capitalized RD&D Expenditures

In this discussion we address capitalization, not the reasonableness, of Edison's RD&D projects. Reasonableness will be discussed in Chapter 8.

In its RD&D testimony, Edison requested $55.748 million in 1992 to capitalize certain expenditures for 19 RD&D projects. (Actual plant additions values are different from requested capital, due to weighting and overheads.) DRA opposed capitalization, arguing that Edison has not shown that any of the projects are used and useful. Previous Commission decisions address capitalization of RD&D, but DRA asked for clarification in this GRC. Specifically, DRA believes that prior guidelines should be amended to restrict capitalization to projects that are needed, cost beneficial, and placed in service. TURN opposed capitalization of electric vehicle expenses, arguing that such rate recovery of prior year costs would be retroactive ratemaking. CEC believes only utility-purchased equipment should be capitalized.

Edison has presented many arguments in support of its capitalization request. Among them are: (1) the 19 projects meet the Commission's standards set forth in D.83-12-068,[43] (2) the FERC Uniform System of Accounts allows capitalization of RD&D, (3) capitalization spreads costs to ratepayers over project useful lives, (4) RD&D has general benefit to ratepayers, (5) DRA's proposed additional guidelines for capitalization are inappropriate, and (6) in response to TURN, fund shifting

43 14 Cal. PUC 2d 15, 58 (1983).

guidelines should supersede previous limitations on electric vehicle expenses.

Edison's capitalization request is summarized in Exhibit 285, which shows that the test year capital request covers expenditures of $19.277 million forecast for 1992, $16.235 million forecast for 1991, and $20.186 million recorded from prior years. (These amounts were later revised in response to an agreement between Edison and DRA regarding electric vehicle costs.) If the Commission should deny capitalization, then Edison requested that all uncapitalized expenditures, both for 1992 and prior years, be expensed in 1992. This expense request is in addition to Edison's test year RD&D expense request. If expense treatment is ordered, Edison also requested: (1) that expensing of the capital items begin in 1993, allowing 1992 expenditures to stay capitalized, (2) that recorded Account 103 (Experimental Plant in Service) amounts and Construction Work in Progress related to RD&D from prior years be amortized in rates over three years, and (3) that Edison be authorized to file advice letters in attrition years 1993 and 1994 to recover increased RD&D expenses for new programs.

6.1.3.1 Clarification of Policy

Edison and DRA correctly cited D.82-12-005[44] and D.83-12-068 in search of Commission guidelines on capitalization of RD&D costs. We will not revise those decisions, but we will provide clarification as DRA requests. D.82-12-005 allowed RD&D to be capitalized only when the plant became used and useful, and offered that exceptions could be treated on a case-by-case basis. D.83-12-068 is more explicit:

> "We interpret the above language to mean that, if there is no reasonable prospect at the outset that a demonstration project involving 'tangible plant' will become used and useful by

44 9 Cal. PUC 2d 833, 847 (1982).

> becoming part of the utility's electric or gas operations, then the expenditures should receive expense treatment for ratemaking purposes. Therefore, if the end result is knowledge, or does not involve tangible plant, the program costs should receive expense treatment. Otherwise, the cost will be capitalized."

We repeat that capitalization can be allowed, by case-by-case exceptions to the used and useful test, when there is a reasonable prospect that tangible plant in a demonstration project will become part of the utility's operations. If the end result of a project is knowledge or information, then the project should be expensed.

We will not adopt DRA's proposed standards for need, cost-effectiveness, and project completion. The elements of need and cost effectiveness lie within any consideration of reasonableness, and strict rules are not necessary for RD&D, which by its nature yields benefits that cannot be precisely defined. Neither is project completion necessary. Although large projects have their own standards for the used and useful test, the Commission routinely authorizes new plant additions on a forecast basis, in GRCs and through the attrition mechanism.

However, further clarification is needed of the term "the utility's electric or gas operations." The D.83-12-068 discussion was directed at RD&D which was clearly to become part of PG&E's production plant. In this GRC most of Edison's requested capitalization projects are outside that category. In this context tangible plant in utility operations means plant that is owned, operated, and maintained by the utility. Production plant obviously qualifies, but capital assets related to DSM and other legitimate utility functions also qualify. Review of these exceptions to the used and useful rule should continue on a case-by-case basis.

Included in Edison's capitalization request are expenditures that were described as expenses in years prior to 1992. If those costs do not qualify for capitalization as clarified above, then recovery as test year expenses would be retroactive ratemaking, and requests for expense authorization will be summarily denied. This is not a clarification, but a confirmation of the retroactive ratemaking doctrine. Prior year expenses cannot simply be capitalized in order to recover them in rates.

DRA witness Jolynne Flores raised a question about the definition of "demonstration" activities within the scope of RD&D. We will characterize the process of technology development as having four steps: (1) laboratory research to determine the scientific facts that govern a proposed project or process, (2) development of equipment or a process from those facts, resulting in laboratory prototypes or processes, (3) demonstration to prove that the technology will work outside the laboratory--akin to field research, and (4) demonstration of the proven technology at utility or customer sites, to encourage customer acceptance and eventual market penetration. Flores refers to activity (4) as "showcasing."

The distinction between demonstration types (3) and (4) is useful for regulatory purposes. Demonstration that a new technology is practical outside the laboratory is a legitimate RD&D function, and expenses for those activities should be recovered in rates. Technology demonstration to build markets, and in some instances to sell more electricity or gas, is not part of the research cycle and should not be capitalized. Type (4) showcasing activities may be justified for other reasons, but for ratemaking purposes we will not allow their costs as RD&D plant additions. Capitalization may still have a place in DSM programs, but we reserve judgment on that issue for case-by-case examination. For now, we will exclude showcasing from RD&D capitalization.

6.1.3.2 Case-by-Case Review of Projects

Edison has presented 19 cases for individual review. Of the 19, only two projects will begin in 1992. For the remaining 17 projects, there is no evidence on the record that the amounts requested are net book values of depreciated assets, rather than original costs, or, with the exception of electric transportation projects, that prior year amounts were not expense items rather than tangible assets. For the transportation projects, more than 65% of prior year expenditures were labor and "other" intangible expenses, which hints that the remaining RD&D projects also have intangible costs within the requested amounts.

(1) Commercial Demonstration ($5.985 million). This request is for demonstrations and showcasing of various energy-efficient technologies. This is clearly showcasing, but should we authorize capitalization as part of Edison's DSM function? Without specific detail of prior year expenditures we will not authorize capitalization of these projects. Edison may revisit the capitalization of prior year projects in its next GRC, if any of the assets will have net book value in the test year.

(2) Commercial and Industrial Demonstrations ($1.950 million). These projects are similar to those in (1) above, but located on customer premises. We deny capitalization, for the same reasons, and because customers may be responsible for O&M.

(3) Advanced Buildings ($3.152 million). These are demonstrations of "smart building" technologies on customer premises. They should not be capitalized, because Edison does not operate and maintain the systems, and the record does not show prior year cost details.

(4) Netcom ($6.093 million). Netcom is a system of electronic meters which allows two-way communication between Edison and its customers. Of the requested amount, only $1.500 million

will be spent in 1992. We will not capitalize any of the requested amounts because the record lacks specific accounting detail.

(5) Distribution Hardware ($232,000). This project is for development and field evaluation of instruments needed to quantify system conditions, driven by increased customer attention to power quality, for example due to data processing loads. This is test equipment needed to develop information, with no reasonable prospect for use in regular operations. We will deny the request.

(6) Digital Protection ($437,000). Like project (5) above, this project will develop and test instrumentation for eventual application to new and existing transmission lines, distribution lines, and substations. This is test equipment and should not be capitalized.

(7) Distribution Automation ($750,000). This project will be completed in 1991. The record lacks sufficient detail to authorize capitalization.

(8) Advanced Communications ($1.200 million). This is a collection of communication projects for various utility system applications. The record lacks sufficient detail to authorize capitalization.

(9) On-site Generation ($5.002 million). The objective of this project is to develop on-site generation and cogeneration technologies, which can be fully integrated with the utility electrical system and customer loads. To date, Edison has extensively investigated available equipment, and the project will continue to investigate feasibility of on-site generation. More than 80% of the request will be expended before the test year. This test is intended to gain information, and there is no detail of prior year costs. We deny capitalization.

(10) El Segundo Controls ($6.800 million). This is a 1991 trial of a distributed control system at Edison's El Segundo Generating Station. The $6.800 million is a three-line budgeted

amount. The record lacks sufficient detail of actual costs to authorize capitalization.

(11) Efficient Burners ($2.225 million). This project is aimed at improved air quality compliance at Edison's generating stations. It was completed in 1990. Again, the record lacks sufficient detail to justify capitalization.

(12) Chino Improvements ($573,000). Most expenditures for this project were incurred prior to 1990 for a battery storage demonstration. Because accounting records are absent, we will deny capitalization.

Edison originally proposed capital expenditures for several electric transportation projects: (13) Electric Vehicles, (14) Electric Roadway, (15) Mass Transit, and (16) Advanced Batteries. The sum of requested capital costs for these four projects is $10.082 million. In the course of hearings Edison and DRA agreed that Edison should be allowed to recover $20.828 million in electric transportation expenditures incurred from 1988 through 1991. Edison requested that $7.379 million of this amount be capitalized, but DRA recommended that the entire amount should be expensed.[45] DRA and Edison also agreed to several issues surrounding funding of Edison's electric vehicles program, which will be discussed in Chapter 8, Section 8.3.6 of this decision. We deny capitalization of the $7.379 million because the record lacks sufficient detail about the capital expenditures. Even if sufficient accounting detail were available, it is uncertain that all of the capital assets were or are used and useful. For example, the electric roadway project is a demonstration of a roadway with a buried cable used to carry a signal that would automate headway between vehicles. There is no reasonable prospect that the project will become part of Edison's operations. As well,

45 Exhibit 112.

the mass transit project is "highly conceptual, and no specific work has been approved," despite the claimed expenditure of $100,000 in 1991.

(17) Compressed Air Storage ($150,000). Of the 19 projects, this is the first which Edison would initiate in 1992. There is insufficient evidence to justify capitalization.

(18) Laboratory Tools ($260,000). Edison seeks capitalization for large laboratory tools used to analyze transmission, distribution, and substation performance. Of the total, $50,000 would be spent in the test year. The record lacks sufficient detail for capitalization.

(19) Texas Instruments Photovoltaic (TI/PV, $10.877 million). This is a joint venture by Edison and Texas Instruments Incorporated, which became publicly known on April 3, 1991, almost a month after DRA's report on RD&D was served. DRA submitted supplemental testimony recommending denial of the project costs because Edison had not sufficiently justified the project. Of the requested $10.877 million, $8.177 million will be expended prior to 1992. Edison seeks no operating expenses for the project, but requests approval of an additional $700,000 in capital costs in 1993. The project has three phases, of which Edison will participate in the first two: (1) laboratory research, (2) a pilot manufacturing plant, and (3) commercial production. The photovoltaic cells under development are called Spheral Solar technology, to be produced from inexpensive, low-purity silicon. Edison claims that ratepayers will eventually benefit from licensing royalties and purchasing discounts during the third phase of the project. We deny capitalization because the record of past expenditures is inadequate, and Edison has not shown a reasonable prospect of tangible plant becoming used and useful. Financing new technologies in order to gain future royalties and product discounts is too speculative to capitalize these expenditures.

6.1.3.3 Summary

We have carefully reviewed the record evidence on capitalization of Edison's RD&D projects. Edison has not met the standards for case-by-case exceptions to our general principles for capitalization of RD&D. The limited evidence on electric vehicles leads us to suspect that many of the requested costs have been depreciated since they were placed in service or are not tangible plant. Some of the projects would fail our standards even if sufficient accounting evidence were before us.

In its comments to the ALJ's Proposed Decision, Edison argued that denial of RD&D capitalization would impose a punitive loss to shareholders of more than $48 million. This allegation is incorrect. First, the disallowances are not punitive, as we discuss further in Chapter 12, Section 12.3. Second, many of the exclusions from rate base are due to Edison's inadequate ratemaking showing. Edison may file in this proceeding information to substantiate its request for capitalization on RD&D projects which received expense treatment at this time.

6.1.4 Capitalized Software

As discussed in Chapter 5, Section 5.10, Edison requested capitalization of $10.1 million in 1992 costs and the 1992 capitalization of about $22 million in 1990 and 1991 software costs which exceeded authorized expense levels. Both of those requests were denied, but a portion of the $10.1 million was authorized as expenses. All of the requested capitalized software costs will be excluded from plant in service. Edison may file additional information on the merits of capitalization within 120 days of the effective date of this order and parties may file responses within 120 days Edison's filing. The Commission may revisit software capitalization issues at that time.

6.1.5 Jet Aircraft and Ontario Airport Hangar

Edison has conceded removal of expenses for Edison's Jet Star aircraft, and we have denied DRA's recommendation to exclude from rates the costs of Edison's Citation aircraft. Because Edison owns the two aircraft, the net book value of the Jet Star is removed from rate base, and all capital-related costs (depreciation, property tax, income tax, etc.) are removed from authorized expenses.

DRA also recommended removal of the capital costs of a hangar which Edison is purchasing at the Ontario Airport. Edison is in the process of moving its aircraft operations--for the two jet aircraft and eight helicopters--from the Chino Airport to Ontario. Edison's lease at Chino will expire at the end of 1993. Edison now pays approximately $200,000 per year to lease a hangar at Ontario. When Edison purchases the hangar, at a price of $1.5 million over two years, the Ontario lease costs would be reduced to $21,000 per year for a ground lease. Edison has agreed to reduce its Ontario lease expenses if it is allowed to purchase the hangar. The Chino lease costs are $35,600 per year, and it appears that for the years 1992 and 1993 Edison would be paying for hangar space at both Chino and Ontario.[46]

We will include the purchase of the Ontario hangar in plant additions, on the presumption that the purchase will go forward by mid-1992, and we will reduce expenses by $179,000 to reflect reduced lease costs at Ontario. We are concerned that the final two years of lease costs at Chino will duplicate Ontario costs. We will remove unnecessary Chino lease costs, which are $35,600 annually, from authorized expenses.

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46 Tr. 54:5594.

6.1.6 Reclassification of Property

Edison must notify the Commission when it reclassifies certain assets from plant in service to other accounts, principally non-utility property. After the filing of its GRC application, Edison notified the Commission of $5.119 million of such transfers. DRA recommended that this amount be removed from Edison's test year plant in service, because failure to do so will overstate the test year rate base. Edison opposed this adjustment, arguing that updating of reclassifications should end when Edison completed its test year budget. Edison claimed that updating of reclassifications is unfair because offsetting new plant additions are not considered.

We agree with DRA. The $5.119 million will be removed from plant additions. The reclassifications are recorded facts, not revised budget estimates.

6.1.7 Palo Verde Completion Work

Edison's requested plant in service for Palo Verde includes $4.529 million for completion work that was budgeted in 1990 by APS, the operator of the plant. Project participants understood that all the completion work would be done in 1990, and Edison based its plant in service forecast on the APS budget. APS later notified Edison that the completion work would not be finished in 1990, and that some 1991 charges would be necessary. Edison estimated that the 1991 charges would be $1.8 million and included that amount in its test year plant in service.

DRA recommended that the Commission remove $2.211 million--the estimated $1.8 million plus overheads--from plant in service because the amount is double counted. Edison responded that the $1.8 million should remain because it will be billed by APS and must be paid.

Edison has compared 1990 budgeted amounts with 1991 billed amounts. DRA is correct that the same $1.8 million is included in both the 1990 budget and the 1991 estimate of billed costs. As Edison's witness Dennis Cox testified:[47]

> "Q Would you agree, though, if your \$1.8 million estimate for 1991 billing is accurate, that the amount that was billed in 1990 should be \$4,329,200 less \$1.8 million?
>
> "A That's possible, if APS did not overrun the budget, which I do not believe they did, yes, that is fine."

We accept DRA's recommendation to remove \$2.211 million from plant in service.

6.1.8 Palo Verde Simulator

Edison included in plant in service two simulators at Palo Verde, one to be completed in mid-1991 and a second to be completed at the end of 1992. DRA disputed inclusion in rate base of the second simulator, in the amount of \$2.019 million, including overheads. Edison believes that the entire Palo Verde capital budget for 1992 should be included in rates, because if the plant simulator does not come on line until the end of 1992, APS will spend the budgeted funds on other projects. DRA opposes this logic and urges the Commission to reject what is essentially blanket authority for APS to substitute projects in its capital budgets.

We agree with DRA and will remove the disputed \$2.019 million from plant additions. The Commission's duty is to allow necessary expenditures in rates, and Edison has not shown that the unidentified projects that APS may substitute for the simulator are necessary. No prudent utility should insist on spending all of its budgeted funds without justification.

47 Tr. 22:1957.

<u>6.1.9 SONGS 1 Cost Cap</u>

SONGS 1, the nuclear generating station jointly owned by Edison and SDG&E, will complete fuel cycle 11 late during the test year. Edison has requested that the Commission authorize Edison to include in its 1993 attrition filing plant additions during fuel cycle 12. In D.91-03-058 the Commission removed the cost-effectiveness of SONGS 1 post-cycle 11 capital additions to I.89-07-004, but DRA has raised an issue relating to cycle 12 plant additions.

In its original testimony DRA recommended that $32.960 million be removed from Edison's 1993 plant additions, because that amount has already been authorized in rates under a cost cap previously ordered by the Commission. During hearings DRA revised its position to recommend that the $32.960 million should be removed from 1991 plant additions, which would affect test year rate base.

In 1983 the Commission opened I.83-10-02 in order to investigate whether SONGS 1 should be removed from rate base. In D.85-12-024 the Commission authorized Edison to spend $201 million (in 1986 dollars) during fuel cycles 9, 10, and 11, effectively allowing the plant owners to continue operations. The $201 million was a capital spending cap based on cost-effectiveness analysis.

In this proceeding DRA has presented evidence that Edison, the plant operator, has deferred to cycle 12 much of the work that was included in justification of the cost cap, which covered cycles 9, 10, and 11. An Edison status report shows that as of December 1990, 10 of the 35 plant modifications listed in calculation of the spending cap are now deferred to cycle 12 or beyond. Five of the nine items for cycle 11 are deferred.

Edison now anticipates that overall capital costs for cycles 9, 10, and 11 will be $203.4 million, slightly above the $201 million cap. Edison does not seek to recover in rates any amounts exceeding the cap, but Edison witness Richard Rosenblum admitted that work planned for cycles 9, 10, and 11 was deferred to cycle 12, at least in part to meet the cost cap.[48] Edison testified that during cycles 9, 10, and 11 the scope of plant additions was modified and expanded by the NRC. DRA believes there are three reasons for Edison's deferral of projects into cycle 12: physical or mechanical constraints, negotiations with the NRC for deferrals, and circumvention of the cost cap. DRA demonstrated that Edison's plant additions were $26.2 million above estimated for cycle 9, $14.8 million above estimated for cycle 10, and $38.6 million below estimated for cycle 11, which suggests that Edison was reluctant to exceed the cost cap. DRA also believes that Edison has not complied with reporting requirements ordered in D.85-12-024.

In response to DRA's recommendation, Edison argues that: (1) Edison was not required to complete the same projects that were contemplated under the cost cap, (2) the Commission has agreed that if unexpected modifications were necessary, the NRC would allow Edison to reschedule them, to limit total expenditures, (3) the plant modification process can change and evolve, (4) the Commission and DRA were well informed of the changes in scope of work, (5) Edison has complied with the $201 million cost cap, and (6) Edison has not acted unreasonably or imprudently.

Edison is correct that it was not required to complete all of the previously identified projects during cycles 9, 10, and 11. Edison performed other NRC-required work during those cycles, and there is no evidence that the work was performed imprudently. However, neither is there evidence that the work is cost-effective. To resolve this issue we divide the work accomplished during cycles 9, 10, and 11 into two parts: old work (anticipated in

48 Tr. 24:2072.

D.85-12-024), and new work (expanded or new projects initiated by the NRC). Edison has spent the $201 million without completing the old work. We cannot determine whether the funds spent for part of the old work are cost-effective. We do know that until at least an additional $32.960 million is spent after the end of cycle 11, the old work is incomplete.

At this point we inspect two conclusions from D.85-12-024:[49]

> "2. Edison should be authorized to complete the SONGS 1 modifications over the next three fuel cycles, subject to an expenditure cap of $201 million in January 1, 1986 prices.
>
> "3. Edison should not be precluded from requesting Commission authorization to exceed the $201 million cap level if because of unforeseen circumstances the costs associated with SONGS 1 modifications are estimated in the future to exceed the cap. Edison will have a heavy burden to justify the cost-effectiveness of such expenditures, and a full showing will be required in support of them."

Conclusion of Law 2 authorizes Edison to expend up to $201 million to complete the SONGS 1 modifications by the end of cycle 11. The modifications are recited in DRA's testimony.[50] We interpret "SONGS 1 modifications" to mean those modifications described in I.83-10-02. It is unreasonable to interpret the language to mean that Edison can freely substitute other projects for those anticipated in I.83-10-02. There is no evidence on this record or in I.83-10-02 that other projects are cost-effective. At a minimum

49 At mimeo. page 14.

50 Exhibit 205, Attachment 11D-2.

Edison should be required to complete the old work at no further cost to ratepayers, and the disputed $32.960 million should be deferred from 1991 plant additions to 1993 or 1994 plant additions. We leave open the ratemaking consequences for Edison if the old work is never completed because SONGS 1 is retired at the end of cycle 11.

Turning to the new work, we agree with Edison that the NRC can authorize rescheduling, but the NRC cannot modify Commission orders on the ratemaking consequences of the rescheduling. D.85-12-024 is quite clear about Edison's obligations, and there is insufficient evidence to show that Edison needs more than $201 million to complete the old work, but what funds are needed to complete the new work? There is no evidence whatsoever on the record that the new work, whether the NRC has ordered it or not, is cost-effective or prudently carried out. Edison has not met its burden of proof for ratepayer funding of the new work.

We will order the following: (1) Edison must remove from 1991 plant additions the disputed $32.960 million, because the old work (modifications authorized in D.85-12-024) has not been completed, (2) Edison may return the $32.960 million to plant in service during 1993 or 1994, for recovery in rates, upon a showing that the old work has been completed, and (3) in accordance with Conclusion of Law 3, Edison must justify rate recovery of any costs for new work. A new forecast of completion is inadequate, because the previous forecast was unsuccessful.

It is not necessary to find that Edison has or has not complied with reporting requirements, exceeded the $201 million cost cap, or acted reasonably and prudently. There is no dispute about the NRC's ability to order or endorse the rescheduling of work. Edison has rescheduled the old work, and we now defer the plant additions associated with that work, to reflect the circumstances of Edison's progress. We cannot accept the new work in rate base until Edison demonstrates cost-effectiveness. We will allow Edison, in this proceeding, to demonstrate the cost-effectiveness of the new work.

6.1.10 Cal Energy Interconnection Facilities

In D.90-09-059 the Commission granted Edison a certificate of public convenience and necessity for a transmission line between Edison's Kramer and Victor substations, and for related facilities.[51] The decision also specified the allocation of costs among Edison, Luz International, and California Energy Company (Cal Energy). Cal Energy has disputed its assignment of costs. In this GRC Edison has included in test year plant additions $14.255 million for capital costs allocated to Cal Energy. Cal Energy may eventually win its dispute, and Edison would be responsible for the previously allocated costs. If Cal Energy does not win its dispute, Edison proposes to return any double recovery of costs by crediting the ERAM account.

DRA opposed Edison's request. DRA prefers to exclude Cal Energy's allocated plant additions from test year rate recovery. Instead, Edison should track the revenue requirement associated with Cal Energy's allocated plant, for eventual recovery from ratepayers if Cal Energy prevails in the allocation dispute.

We endorse the status quo in this matter. Cal Energy has not yet won its cost allocation dispute, and the Commission's orders on cost allocation remain in effect. We will exclude Cal Energy's allocated plant from plant additions, and allow Edison to book into an interest-bearing memorandum account all capital-related revenue requirement associated with Cal Energy's $14.255 million in plant. If Cal Energy's plant is eventually and finally reassigned, Edison may seek recovery of the memorandum

51 37 Cal. PUC 2d 413, 467 (1990).

account balance and of future revenue requirement related to the reassigned plant. If this should become necessary, Edison can make the filing as a petition for modification in this GRC. Otherwise, Edison should terminate the memorandum account by advice filing.

6.2 Other Issues

6.2.1 Property Held for Future Use

In Edison's 1988 GRC the Commission adopted property held for future use (PHFU) guidelines which generally require that the properties must have specific uses and cannot stay in PHFU for periods exceeding 10 years (for production plant and new transmission lines), 5 years (for other transmission and distribution plant), or 3 years (for general plant). Case-by-case exceptions can be granted if: (a) there is still a definite plan and need to retain the item in PHFU, (b) economic analysis justifies the retention, and (c) there are mitigating circumstances to require the retention.[52]

At the end of 1989 Edison's PHFU balance was $17.6 million, of which $14.3 million does not meet the guidelines. Edison has reclassified about $6.0 million in properties, leaving $8.323 million in property for which it seeks PHFU treatment under the exceptions. DRA opposed Edison's request, claiming that the properties fail to meet the standards for exceptions. The disputed $8.323 million is for 27 properties: four production properties at three sites, three transmission substation sites, three transmission line sites, and 17 distribution substation sites. The average time in rate base for the disputed properties is 17 years.

Edison testified that the production sites are necessary to meet a general need for future generation. Three sites are necessary because Public Resources Code § 25503 requires that three

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52 D.87-12-066, Appendix B.

alternate sites be presented to the CEC for any single generation project. Edison's analysis shows that ratepayers will benefit in the long run from retention of one of the properties, compared to sale and later repurchase. DRA opposed Edison's conclusion, claiming that the repurchase prices are speculative and no specific use has been demonstrated. Edison provided DRA with extensive supporting workpapers for other properties, but all of the economic analyses are not in evidence.

We will exclude the disputed properties from PHFU. The guidelines set specific reasonable time limits for retention of plant. Beyond those limits the higher standards in the guideline exceptions are required. Edison has failed to meet the higher standards. For production plant: (1) presentation of alternative sites to the CEC does not justify keeping four properties in rate base, (2) Edison's economic analysis is incomplete because the benefits of retaining the site eventually used must be offset by the costs of retaining the alternative sites, (3) there is no evidence that Edison can outperform the real estate market in general, (4) the market for the land in PHFU is speculative,[53] and (5) Edison has not justified the mitigating circumstances required by the guidelines. For other plant, Edison has shown that some mitigating circumstances are present (e.g., approval of overhead access by other agencies, and the need for condemnation at a repurchased site), but the economic benefits of PHFU retention far in excess of the guideline periods are not sufficient to overcome the risks that Edison's economic assumptions are too optimistic.

In summary, Edison has not justified granting exceptions to the PHFU guidelines. Ratepayers pay a premium for Edison's investments in PHFU, due to income tax charges on authorized net

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53 Exhibit 128, Attachment 6-6, page 6-2.

for return. We are not convinced that Edison should expose ratepayers to real estate investment risks beyond the risks incorporated in the PHFU guidelines.

6.2.2 Nuclear Design Documentation

The NRC has mandated an industrywide program to document the design bases for operating nuclear plants. Edison is performing the work as required and is booking the costs to plant Account 182.2, with amortization to Account 407. Edison requested that unamortized amounts in Account 182.2 be included in rate base, consistent with past treatment of other deferred debits. DRA opposed inclusion in rate base, arguing that capitalization of the design documentation is contrary to generally accepted accounting principles, and that capitalization has been specifically denied by FERC. DRA produced a letter from FERC staff to the Virginia Electric and Power Company denying capitalization of nuclear plant design documentation. Edison responded that FERC made no comment about inclusion of costs in rate base, whether the costs are capitalized or booked as deferred debits for amortization. If the design documentation was created for a new plant it would be capitalized, and documentation for existing plants should be treated the same way.

The design documentation costs themselves will eventually be paid by ratepayers, whether through depreciation of capital costs or amortization of deferred debits. At issue is whether shareholders should earn a return on the undepreciated or unamortized amounts. There is no evidence that the costs are unreasonable, and we will allow Edison to earn a return on unamortized amounts over the lives of the related nuclear plants, unless we are later convinced that the plants should be removed from rate base.

We do not dispute FERC's opinion that design documentation should not be capitalized, but all of rate base need not be capitalized. The return of the deferred debits to shareholders will be made through Account 407, and Edison should take care that the design documentation costs are excluded from depreciation treatment.

6.2.3 Advances for Construction

Edison and DRA waged a battle of statistics over the best technique for forecasting customer advances for construction, which reduce rate base. Edison based its estimate on linear regression over 13 years of data, correlating recorded advances against the year of record. DRA correlated advances against distribution line additions over the same 13 years, to determine a ratio that can be multiplied by test year line additions to forecast customer advances. Edison believes its technique is best because the sum of statistical "residuals" and the sum of squared residuals are smaller than those measures under DRA's method. DRA claims that the sum of absolute values of residuals is smaller using its method. The difference in rate base is $2.601 million.

Neither party simply correlated recorded advances against both year of record and distribution line additions, to determine which correlation is best. We have done that arithmetic, and will rely on the conventional measure r-squared, rather than residuals, as the best indication of correlation. The data show that distribution line additions are a better predictor of customer advances (r-squared = 0.967) than year of record (r-squared = 0.907). We will adopt DRA's recommendation.

6.2.4 Working Capital

Working capital has two elements: materials and supplies, and working cash. Edison and DRA dispute one element of materials and supplies, and several elements of working cash.

6.2.4.1 Materials and Supplies

Edison estimated its 1992 materials and supplies inventory by escalating the recorded 1990 end-of-year balance to 1992 at 5% per year. DRA noticed that the 1990 balance was more than 16% higher than the 1989 balance. Therefore, DRA estimated the 1992 inventory level by escalating the 1989 balance forward, using the same 5% per year. After month-by-month weighting, the amount in dispute is $4.323 million in rate base.

We agree with DRA that the 1989 end-of-year inventory is an appropriate basis for test year inventories. We will adopt DRA's rate base reduction.

6.2.4.2 Working Cash

Working cash itself has eight operational cash elements which are derived from account records, plus a cash requirement based on a lead-lag study of estimated utility cash flows. DRA has disputed several parts of this construction. DRA and Edison agree that working cash should be calculated using adopted expenses, escalation rates, and sales forecasts. Although working cash disputes seem overly detailed at first glance, for Edison a change of one day in cash flow could result in a $10 million change in rate base.

DRA recommended a reduction in recorded account balances for "other accounts receivable," due to nonrecurring charges of $4.0 million for earthquake damage claims and $1.4 million for reimbursable fire damage at Edison's office building. Edison did not respond to DRA's recommendation, either in rebuttal testimony or in briefs. We accept DRA's reduction.

The lead-lag calculation considers the timing of both Edison payments and customer revenues. On the payment side, DRA recommends increasing the average time for purchased power payments from 39.65 days to 42.28 days, to exclude payments to Kern River Cogeneration Company (KRCC), an Edison affiliate. DRA determined that payments to KRCC are made in 12.5 days, unfairly decreasing the average lag between receipt of the power and payment by Edison. Edison did not respond to DRA's recommendation, and we will adopt it. Early payments to utility affiliates and subsidiaries should not be considered in working cash calculations.

On the customer revenue side, DRA disputed Edison's estimate of the impacts of Edison's planned late payment charge. Edison's recorded revenue lags during 1989 for commercial, industrial, and agricultural customers were 43.55, 45.53, and 44.36 days, respectively. Edison used 40 days to estimate test year working cash, reflecting the effects of the late payment charge on customer behavior. DRA recommended a further reduction of 2.2 days.

The forecasts of customer behavior are no more than educated guesses. We will adopt Edison's forecast, but with a note of concern about application of the late payment charge. During hearings Edison announced that it plans a six to eight day grace period in application of the late payment charge, which would tend to increase revenue lag days. We remind Edison that if its late payment charge is eventually approved, it should enforce the charges fairly and uniformly, in accordance with filed tariffs.

In its comments on the ALJ's Proposed Decision, the California Department of General Services pointed out that late payment charges to governmental facilities are limited by the California Governmental Code. We assume that Edison's lag day estimates have considered this constraint.

<u>6.2.5 Amorphous Core Transformers</u>

Although the parties do not mention this issue in their briefs, the joint comparison exhibit shows a dispute over inclusion of amorphous core transformers in rate base, in the amount of $1.272 million. Amorphous core transformers cost more than conventional iron core transformers, but they are more energy-efficient. DRA believes the transformers should be excluded from rate base until cost savings are further documented.

We will allow the amorphous core transformers in rate base, because they meet the guidelines for RD&D capitalization and capital costs are small. Edison should revisit costs and benefits before significantly expanding use of the transformers.

7. Depreciation

Only Edison and DRA presented testimony on depreciation expense and depreciation reserve. DRA agreed to Edison's reduction of the average depreciation rate from 3.72% to 3.70%, based on increased plant lives. DRA recommended depreciation expenses $20.916 million lower than Edison, but the difference is driven entirely by DRA's use of later data for depreciation reserve balances and disputed plant in service. We adopt DRA's use of the later data. The parties have agreed to use an interpolation scheme to determine test year depreciation expense from adopted plant in service. The record is less clear how depreciation reserve should be interpolated, but we assume the same formula applies.

Ratepayer funding of trust funds for future nuclear plant decommissioning is treated as a depreciation expense. There is one dispute over decommissioning revenue requirement. DRA and FEA recommend a reduction of $779,000 from Edison's estimated revenue requirement, to reflect updated cost studies at SONGS and Palo Verde. Although this difference is less than 1% of the decommissioning expense, DRA believes the reduction is appropriate, to minimize ratepayer costs. Edison believes the adjustment is unnecessary. We will adopt the $779,000 reduction. Adjustments such as these are inconsequential in the long run, but the reduced costs are consistent with the most recent cost studies and take very little effort to implement.

FEA also expressed concern that Edison's estimated trust fund earnings rates--5.25% for the qualified trust, and 6.00% for the nonqualified trust--are too low, and that Edison's 25% contingency factor for decommissioning costs might be too low. FEA recommended further scrutiny of these issues, in this proceeding or in Edison's next GRC. We will order a showing on these topics by Edison in its next GRC.

8. Research, Development, and Demonstration

In Edison's last GRC the Commission commented that although Edison's presentation was generally very professional, its conduct in the RD&D area was unacceptable, notably in making late revisions to electric vehicle programs. In D.87-12-066[54] the Commission warned:

> "Edison is put on notice that it should take steps to insure that this does not reoccur and that any future late additions or substantial changes will simply not be considered."

Despite this explicit warning, Edison's showing again has suffered from problems of late program revisions, unexplained capital costs, inconsistency between exhibits and briefs, and attempts at wholesale capitalization of prior year expenses and undepreciated capital costs. We will base our decisions on the record before us, but with the above warning in mind. In future showings on RD&D matters, Edison should: (1) identify all expenses and capital costs, (2) identify projects for which future royalties and licensing fees are likely to be returned to ratepayers, (3) demonstrate net book values and depreciation charges related to capitalized RD&D projects, and (4) in general, improve its showings on the ratemaking treatment of RD&D programs.

Edison's fragmented showing on ratemaking treatment convinces us to order a financial audit of Edison's RD&D expenditures from 1988 through 1992, to be submitted in Edison's next GRC. The audit should: (1) identify all recorded expenses and capital costs, with attention to capital costs meeting the Commission's standards for RD&D capitalization, (2) identify direct benefits sponsored by the Electric Power Research Institute (EPRI), noting any projects directed or developed by Edison, (3) for

54 26 Cal. PUC 2d 392, 454 (1987).

capital assets, determine where the items are located and who is responsible for O&M, and (4) track all entries in Account 103, including transfers to utility plant and non-utility plant. The audit will be coordinated by CACD, at Edison's expense, using funds redirected from the approved RD&D expenses. A final report should be completed by June 30, 1993.

8.1 RD&D Policy

In this opinion we have clarified two RD&D guidelines, to restrict plant that is eligible for capitalization and to exclude showcasing from RD&D capitalization.[55] In future proceedings Edison should also exclude all showcasing from RD&D budgets. We will authorize some showcasing expenses in this GRC, but Edison should include showcasing as a DSM activity, with appropriate cost-effectiveness justification.

We confirm that Edison's RD&D efforts should strive for a balanced portfolio of supply, transmission and distribution, and end use projects.

We defer policy considerations for electric vehicles and electric transportation in general to I.91-10-029, which was approved October 23, 1991, or other appropriate proceedings. Any policy direction on electric transportation given herein will be interim in nature.

Edison and DRA have agreed that any shifting of RD&D funds among authorized or new programs should be done by application if more than 50% of the funds are redirected, by advice letter if more than 20% but less than 50% of program funds are redirected, and at Edison's discretion if shifted funds are less than 20% of authorized program expense levels. We accept these limitations, but clarify that the percentages apply to both funding source and funding target programs. For example, if Project A is

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55 Chapter 6, Section 6.1.3.1.

authorized at $100,000 and Project B at $1,000,000, then shifting of more than $20,000 from Project B to Project A would require advice letter approval, and shifting of more than $50,000 would require an application by Edison. According to this guideline an application would be required for any entirely new RD&D project.

In D.90-09-045[56] the Commission authorized use of RD&D funding ranges in future GRCs. Edison has argued that a funding range should be set in this proceeding, consistent with the spirit of D.90-09-045. DRA disagreed, pointing out that the language in D.90-09-045 explicitly puts the issue in Edison's next GRC (scheduled to be for a test year 1995). DRA now seeks clarification on exactly how funding levels will be set. We agree that D.90-09-045 does not apply to this proceeding. We defer the calculation of funding ranges to R.87-10-013, where all utilities can participate. Edison's request to set a funding range is another last minute RD&D issue that arrived too late for consideration in this GRC.

We have heard testimony and argument on RD&D that touches on fundamental utility obligations. One of Edison's major RD&D efforts is entitled "Customer Air Quality Improvement Program," for which Edison requests $4.055 million in expenses. Much of Edison's testimony on the benefits of the three projects it proposes under the air quality program emphasized what we will call social efficiency. Edison claimed that ratepayer funding of the program will help customers meet their air quality requirements, stay competitive, and remain in Southern California. DRA and other parties (e.g., TURN and Industrial Users, or IU) opposed Edison's request, arguing that societal benefits are different from ratepayer benefits, all ratepayers should not subsidize a few customers, and air quality compliance is the responsibility of

56 37 Cal. PUC 2d 390, 393 (1990).

businesses and local communities. They conclude that Edison's program is an inappropriate extension of the public utility role. The Natural Resources Defense Council (NRDC), a strong environmental advocate, hesitated to endorse Edison's fuel switching and electro-technology activities. NRDC witness Ralph Cavanagh recommended that approval should await further study in R.91-08-003 and I.91-08-002, the current DSM rulemaking.

The essential issue which emerges from the parties' diverse positions is the fundamental fairness to ratepayers, or social equity, of allowing a public utility to fund air quality improvements which may not be directly linked to delivery of energy. The balance of social fairness against economic efficiency is a classic public policy dilemma. Edison states that utility participation is an efficient way for California businesses to stay competitive in difficult economic circumstances. This may be true. Other parties state that ratepayer funding of Edison's participation is unfair. This is more difficult to assess but may also be true.

We decline to decide this important policy issue solely on the record developed in this GRC. We agree with the NRDC that the DSM rulemaking, R.91-08-003 and I.91-08-002, will provide an appropriate forum for a more comprehensive study and we order that this issue be examined in that proceeding as soon as practicable. We urge the participation of all California regulated energy utilites and interested customer groups in developing a thorough record.

For the immediate three-year period represented by this GRC cycle, however, we believe that Edison has supported its funding request for its Customer Air Quality Improvement Program. This program is discussed further in Section 8.3.2. of this chapter.

On October 11, 1991, after submission of Phase 1, the Governor approved Assembly Bill 2054, which added PU Code § 740.4, effective January 1, 1992. The new Code section requires that the Commission allow reasonable utility expenses for business retention and other economic development programs "to the extent of ratepayer benefit." Section 740.4 does not specify whether the benefit must be net of expenses or a gross benefit before expenses, which would require subsidies by ratepayers. The Commission has had no opportunity to consider how the those benefits should be defined and calculated. We will review implementation of § 740.4 in the DSM rulemaking, R.91-08-003 and I.91-08-002, and do not base our authorization or denial of Edison's program on a "quick read" of that statute.

8.2 Ratemaking

Because we have concluded that the RD&D funding ranges ordered in D.90-09-045 do not apply in this GRC, we will adopt funding levels for specific programs. We will continue Edison's existing one-way balancing account, which allows that unspent RD&D funds may be spent in subsequent years, through the end of each GRC cycle. We expect to see an advice filing from Edison within 90 days after the end of 1991, to dispose of any unspent funds from the 1988-1991 cycle by a credit to the ERAM balancing account.

DRA has recommended that all royalties, licensing fees, and other revenues attributable to Edison's RD&D programs should be credited to an interest bearing memorandum account. The account balance would be returned to ratepayers in the next GRC. Edison agrees in principle, but testified that no such revenues are forecast for the test year. We will adopt DRA's recommendation.

Edison believes that RD&D and DSM activities should be exempt from any O&M expense reductions to account for productivity or Edison's Cost Containment program. This is reasonable, due to the remoteness of these expenses from ordinary production and delivery of energy, and because DSM expenditures have been unstable from year to year.

8.3 RD&D Programs

Edison's proposed RD&D programs are listed on Table 5, with footnote discrepancies between evidence and briefs. There are seven major areas of expenditures. We will authorize no capitalization of RD&D costs; all adopted amounts are to be expensed. In a few instances requested 1992 capital costs may be expensed for recovery in rates.

TABLE 5
TEST YEAR RD&D EXPENDITURES

(Expenses in Thousands of 1988 $, Capital in Thousands of Nominal $)

LINE	PROJECT	EDISON REQUESTED EXPENSE (1)	CAPITAL (2)	1992 CAPITAL (3)	TOTAL (1)+(2) (4)	EXPENSES DRA (5)	ADOPTED (6)
	CUSTOMER ENERGY TECHNOLOGY						
1	COMMERCIAL DEMONSTRATION	$4,728	$5,965	$1,800	$15,795	$1,182	$1,995
2	COMMERCIAL - INDUSTRIAL DEMONSTRATIONS	|	1,950	750	|	|	|
3	ADVANCED BUILDINGS	|	3,152	700	|	|	|
4	TECHNOLOGY TRANSFER	4,643	0	0	4,643	0	0
5	CTAC	1,600	0	0	1,600	0	1,600
6	NON-ELECTRIC TECHNOLOGIES	0	0	0	0	1,000	1,000
	CUSTOMER AIR QUALITY IMPROVEMENT						
7	ROG AND COMPLIANCE	1,605	0	0	1,605	0	1,605
8	NEW REGULATIONS	1,563	0	0	1,563	0	1,563
9	NOX COMPLIANCE	887	0	0	887	0	887
10	AIR QUALITY TECHNOLOGIES	0	0	0	0	400	0
	ELECTRIC AND COMMUNICATIONS SYSTEMS						
11	NETCOM	7,180	6,093	1,500	13,273	7,180	8,680
12	DISTRIBUTION HARDWARE	4,051	232 [1]	80	4,720	4,051	4,201
13	DIGITAL PROTECTION	|	437 [1]	70	|	|	|
14	CONTROLS AND DIAGNOSTICS	1,943	0	0	1,943	1,943	1,943
15	ADVANCED COMMUNICATIONS	1,689	1,200	500	2,889	1,489	2,189
16	ON-SITE GENERATION	1,099	5,002	800	6,101	1,099	1,899
17	TI/PV	0	10,877	2,700	10,877	0	0
18	ADVANCED CONCEPTS	762	0	0	762	762	762
19	DISTRIBUTION AUTOMATION	0	750	0	750	0	0
	SYSTEM ENERGY MANAGEMENT						
20	EL SEGUNDO CONTROLS	3,545	6,800	0	10,345	3,545	3,545
21	EFFICIENT BURNERS	1,693	2,225	0	3,918	1,693	1,693
22	CHINO IMPROVEMENTS	593	573	50	1,166	593	643
23	RENEWABLES	1,688	0	0	1,688	1,688	1,688
	ENVIRONMENTAL QUALITY						
24	AIR QUALITY	2,505	0	0	2,505	2,505	2,505
25	OCCUPATIONAL HEALTH	1,788	0	0	1,788	1,788	1,788
26	NATURAL RESOURCES	1,427	0	0	1,427	1,427	1,427
27	URBAN INFLUENCES	1,037	0	0	1,037	1,037	1,037
28	STRATEGIES	844	0	0	844	844	844
	ELECTRIC TRANSPORTATION						
29	MASS TRANSIT	760	0	0	760	760	760
30	ELECTRIC VEHICLE TESTING	1,348	0	0	1,348	1,348	1,348
31	INFRASTRUCTURE	|	0	0	0	|	|
32	BATTERY DEVELOPMENT	|	0	0	0	|	|
33	PRIOR YEAR EXPENDITURES	0 [2]	7,379 [3]	0	7,379	7,379	0 [4]
	OTHER						
34	RESEARCH SUPPORT	3,062	0	0	3,062	3,062	3,062
35	COMPRESSED AIR	0	150	150	150	0	0
36	LABORATORY TOOLS	0	260	50	260	0	50
37	EPRI	N/A	0	0	N/A	4,018 [5]	0
38	TOTAL	$52,040	$53,045	$9,150	$105,085	$50,793	$48,714

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[1] EXHIBIT 278, PAGE 3-17A SHOWS $1,419 FOR THE SUM OF THESE TWO AMOUNTS.
[2] ASSUMING $13,449 ALREADY RECOVERED IN RATES.
[3] FROM EXHIBIT 112 AND EXHIBIT 278, PAGE 4-5. EDISON OPENING BRIEF AND EXHIBIT 225 SHOW $10,082 FOR ELECTRIC TRANSPORTATION CAPITALIZED.
[4] ALL REDIRECTED PRIOR YEAR EXPENDITURES EXCEEDING $100,000 PER YEAR SHOULD BE CONSIDERED AS UNSPENT IN THE ONE WAY BALANCING ACCOUNT.
[5] IF EDISON IS ORDERED TO JOIN EPRI.

8.3.1 Customer Energy Technology

Edison requested $10.971 million in expenses and $11.067 million in capital costs for five projects (Commercial Demonstration, Commercial-Industrial Demonstration, Advanced Buildings, Technology Transfer, and the Customer Technology Applications Center, or CTAC). DRA recommended authorization of 25% of Edison's expense request for the first three programs, zero for Technology Transfer, and zero for CTAC. DRA criticized these programs because they overemphasize load building, mischaracterize load factor benefits by building off-peak load, unfairly emphasize electricity over other energy sources, and unfairly benefit customers, not ratepayers. DRA also recommended that any activities which involve direct customer contact, including technology transfer programs, should be in Edison's DSM budget, not RD&D.

In order to stress fuel use reduction over fuel switching, we will adopt DRA's expense recommendations, with two exceptions. First, we will authorize the requested $1.600 million for CTAC. Second, within Edison's capital request is $3.250 million for 1992 capital costs. We will allow 25% of those amounts, to be recorded as expenses. The record does not support capitalization of any of the requested capital costs, and expensing of prior year expenditures would be retroactive ratemaking. For all customer energy technology expenses, Edison should in future years distinguish RD&D expenses from DSM expenses, using our announced guidelines.[57] Showcasing expenses should be removed from RD&D.

8.3.2 Customer Air Quality Improvement

Edison proposes three projects under this program. The total funding request is $4.055 million in expenses broken down, by

57 Chapter 6, Section 6.1.3.1.

project, as follows: NOx Rule Compliance, $887,000; ROG and Air Toxic Rule Compliance, $1,605,000; New AQMP Regulations, $1,563,000. Among the program's objectives are demonstration of technologies to reduce nitrogen oxides (NOx) at customer sites; assessing, anticipating, and providing input to air quality regulations; energy efficiency improvements which will lead to compliance with air quality regulations; and aid to customers in reducing and controlling air emissions. These objectives will be pursued by the identification, evaluation, development, and demonstration of state-of-the-art or newly emerging air quality improvement technologies for appropriate large-scale transfer to customers.

DRA and other parties oppose each of Edison's projects, alleging that the Customer Air Quality Improvement Program is unfairly outside the scope of the utility function. DRA recommended that Edison instead begin a $400,000 program to provide customers with information (not equipment or services) on air quality and energy efficient technologies.

We are not persuaded that Edison's Air Quality Improvement Plan lacks ratepayer benefit. Moreover, we believe that DRA's proposal may be both too limited in scope and underfunded to achieve the desired results. In D.90-09-045, an interim opinion in our RD&D rulemaking, R.87-10-013, we stated:

> RD&D priorities and programs should consider and be responsive to environmental concerns in the short-, mid-, and long-term. RD&D activities should be conducted with a particular awareness of the need to address issues such as water and air quality, and hazardous waste prevention.[58]

We approve Edison's funding request. We believe that the program will provide short-term response to environmental problems in the South Coast Air Basin. We caution Edison, however, that in

58 37 Cal PUC 2d 390, 397, Appendix C (1990).

undertaking the program it should be mindful of our goal, restated in our DSM Rulemaking and equally applicable here, of encouraging energy efficiency and energy conservation.[59] Edison should refrain from activities and project implementation which may frustrate those goals.

8.3.3 Electric and Communications Systems

Edison requested $16.724 million in expenses and $24.591 million in capital costs for RD&D programs to improve efficiency and reduce costs at Edison's operating facilities. There are nine projects. DRA does not contest Edison's requested expenses for seven of them: Netcom, Distribution Hardware, Digital Protection, Controls and Diagnostics, Advanced Communications, On-site Generation, and Advanced Concepts. For those seven projects we will authorize Edison's requested expenses and the expensing of the requested 1992 capital costs. The eighth project is Distribution Automation, for which Edison seeks no expenses, but requested $750,000 to recover capital costs made prior to 1992. We deny that request.

Edison's final request in this area was for $10,877 million in capital costs for the TI/PV project. The record shows that Edison plans to expend only $2.700 million in 1992, in payments to Texas Instruments Incorporated, its joint venture partner. DRA recommended no capital funding in 1992, because Edison does not own the tangible assets. If the Commission approves the project, DRA recommended expense amortization over three years. DRA's opposition is based on the inadequacy of supporting information from Edison. This project arrived in the GRC after commencement of hearings, and the only information available was a short press release. We deny ratepayer funding of this project because: (1) supporting information is inadequate,

59 R.91-08-003, I.91-08-002, Appendix A, p.5 (mimeo).

(2) all but $2.700 million was expended prior to the test year, (3) the remainder does not qualify for capitalization because the assets are not owned by Edison, and (4) Edison's request arrived late, despite explicit Commission warning in D.87-12-066.

8.3.4 System Energy Management

Edison requested $7.519 million in expenses and $9.598 million in capital costs for energy management improvements at Edison's production facilities. Only $50,000 of the capital amount is for 1992 expenditures. DRA recommended approval of only of the expense amounts. We will approve all of the requested expenses plus the 1992 capital amount, to be expensed for ratemaking purposes.

8.3.5 Environmental Quality

Edison requested $7.601 million in expenses, and no capital costs, for five projects aimed at long-term environmental research. Funding for these projects was reduced in 1990, but DRA supports Edison's return to a strong program. We will approve the expenses.

8.3.6 Electric Transportation

In discussion of plant additions in Chapter 6, Section 6.1.3.2, we have denied capitalization of Edison's requested $7.379 million for electric transportation projects. Of that amount, $6.298 million was expended from 1988 through 1991 for electric vehicle development. According to a May 3, 1991 agreement[60] between Edison and DRA, Edison's revised request for electric transportation RD&D is to recover $2.108 million in test year expenses and to retain or recover $20.828 million in prior year costs (now that capitalization of the $7.379 million has been denied). Other elements of the agreement are treatment of electric transportation as a separate RD&D program, fund shifting rules, and

60 Exhibit 112.

a $2 million limitation on DSM funding for electric vehicle programs. DRA proposed a method to return unrecovered portions of the $20.828 million to Edison through a debit to the Electric Revenue Adjustment Mechanism (ERAM) balancing account.

TURN opposed the agreement between Edison and DRA, for two reasons. First, Conclusion of Law 71 in D.87-12-066 fixed maximum electric transportation expenditures at $100,000 per year. Recovery of prior year costs above this amount contradicts explicit Commission intentions. Edison believes that fund shifting rules allowed it to supersede the conclusion of law. Second, TURN claimed that the requested recovery of prior year expenses is retroactive ratemaking because the expenditures were not authorized when they were incurred.

Although it had no explicit authorization from the Commission, Edison presented evidence that it sought Commission guidance when it shifted RD&D funds to electric vehicle programs. Edison specifically referred to: (1) Finding of Fact 139 in D.87-12-066, which allowed Edison to shift RD&D programs, (2) a letter to Edison from Commission President Stanley Hulett, in which he stated his position that Edison could allocate monies within its existing RD&D budget for electric vehicle research and demonstrations, and that President Hulett and Commissioner Donald Vial agreed that Edison's electric vehicle expenses were reasonable, (3) a letter from Acting Executive Director Wesley Franklin to the California Electric Vehicle Task Force, supporting a task force report in principle, (4) notice to the Commission in RD&D status reports that Edison incurred electric vehicle capital costs of $2.202 million in 1988, in excess of authorized amounts, and (5) informal discussions with DRA and the Public Staff Division (PSD), its predecessor.

We conclude that recovery of Edison's prior year electric transportation costs in test year rates would be both unwise and inappropriate. However, with respect to retention of any such costs already recovered in rates, we reject the notion that these amounts should be returned to ratepayers.

Although it is true that Conclusion of Law 71 in D.87-12-066 authorized $100,000 of funding for electric transportation RD&D, Finding of Fact 139 in this same decision allowed Edison to make RD&D program changes without Commission approval. Subsequent to D.87-12-066, the Commission issued D.90-09-045 which dealt with the regulatory treatment of RD&D in the electric and gas industries. In D.90-09-045 the Commission reiterated the theme of utility flexibility in RD&D programming and budgeting. The Commission also spoke of the need for greater RD&D flexibility and adaptability to respond to the increasing competitive and environmental pressures faced by energy utilities. The Commission went on to state "that RD&D programs can and should be a valuable resource for utilities as they face.... the need to respond to the environmental challenges of the future."[61]

Clearly, environmental degradation caused by internal combustion vehicles is a contributing source to air emission problems in the Edison service territory. Electric vehicles have the potential to be a partial answer to the environmental concerns in this area. To the extent that RD&D efforts in electric vehicles move society closer to the day that this technology is a viable market alternative, utility expenditures certainly fall within the environmental goal as part of the Commission's RD&D objectives.

In determining whether Edison had the ability to shift RD&D program funds into electric transportation, we conclude that although no explicit Commission authorization was ever granted, there is sufficient evidence to indicate that Edison had received Commission guidance to reallocate funds into the RD&D electrical vehicle program. We reject the ALJ's interpretation of Conclusion

61 [37 Cal. PUC 2d 390-391 (1987)]

of Law 71 in D.87-12-066 that the $100,000 authorized was a maximum limit that Edison could spend on its electrical vehicle. When read in context with Finding of Fact 139 in D.87-12-066 and with D.90-09-045, it is not at all clear that the Proposed Decision's absolute characterization of Conclusion of Law 71 is warranted. As such, in keeping with the Commission's statements on the role of RD&D in responding to the environmental challenges faced by the citizens of this state, we will not penalize Edison for the $13.449 million previously spent and recovered for the electric vehicle program.

In their comments to the ALJ's Proposed Decision, both TURN and DRA pointed out evidentiary conflicts in the ratemaking status of the requested $20.828 million in prior year expenditures. The language of Exhibit 112 suggests that none of the amount has yet been recovered from ratepayers. TURN believes that all of the $20.828 million has been recovered in rates, by shifting of RD&D funds previously authorized for other purposes.[62] DRA believes that $13.449 million has already been recovered, and in this proceeding Edison has sought to recover the remaining $7.379 million.

We agree with DRA's interpretation of the past ratemaking recovery of the $20.828 million Edison has spent on this program. Therefore as we have stated above, we will not penalize Edison in the amount of the $13.449 million already expensed and collected from ratepayers. The $13.449 million must be excluded from historical recorded expenses to remove its impact from future expense estimates. Furthermore, we will allow neither capitalization nor expensing of the $7.379 million of previous expenditures that Edison requests be recovered in future rates.

62 Exhibit 269 (DRA), pp. 4-11, Paragraph 24.

We will authorize the agreed upon $2.108 million for test year expenses, and we will adopt the conditions on program scope, reporting, fund shifting, and DSM budgeting that are contained in Exhibit 112. We note that Exhibit 112 refers to "CEC's DSM testimony." That testimony was received as Exhibit 411.

8.3.7 Other Expenses

Edison requested $3.062 million in expenses for research support. DRA does not contest the request, and we will adopt it.

Edison requested $150,000 in 1992 capital costs for a compressed air storage program. DRA opposed the request, pointing out that the project would be built only if Edison's proposed merger with SDG&E was approved. The merger will not go through, and we will not approve the capital cost.

Edison requested $260,000 in capital costs for laboratory tools, of which $50,000 is planned for 1992. We deny capitalization of costs prior to 1992 due to inadequate evidentiary support. We will approve the 1992 amount, but it should be expensed, not capitalized.

In its GRC application, Edison did not request test year funding for membership in EPRI, but it requested authority to seek additional funding in the "$12 to $13 million range" in 1993 and 1994. This request was contingent on Edison's negotiation of EPRI policy changes that would allow for revised dues, utility discretion over EPRI funds, and changes to EPRI's committee structure. Edison was previously an EPRI member, and the Commission allowed 1988 test year funding of $17.679 million for EPRI dues. However, Edison withdrew from EPRI in mid-1989.

During Phase 1 hearings Edison revised its position. Edison now intends to rejoin EPRI, effective January 1, 1992, contingent on ratepayer funding of Edison's other RD&D programs. If the Commission approves funding "near the $55 million level," Edison will rejoin EPRI and pay its dues out of funds redirected from other programs. Edison testified that although dues are about

$18 million, Edison would have control over about $8 million of that amount. Essentially, EPRI would spend $8 million of Edison's dues to perform RD&D work now planned by Edison. Thus only $10 million of Edison projects would be eliminated by joining EPRI. DRA opposes this contingent request, characterizing it as blackmailing the Commission.

Edison's request for funding of EPRI dues came very late in the proceeding. Up to this point, we have approved $45.059 million in expenses and no capital costs for Edison's RD&D programs. We will not authorize an additional $10 million to bring funding up to the $55 million level, in hopes that Edison will join EPRI, nor will we order Edison to join. Edison apparently does not believe that EPRI membership is necessary, or it would make a stronger commitment to joining, and the Commission should not authorize unnecessary expenses. We decline further consideration of test year expenses that are contingent on Commission approval. If Edison chooses to join EPRI it may do so, but if it will pay EPRI dues through redirection of authorized RD&D funds, it must follow the announced fund shifting procedures.

8.3.8 Summary

The adopted RD&D expense level is $48.714 million (in 1988 dollars), which is 12.2% higher than authorized 1988 expenses and 69.6% higher than 1988 expenses exclusive of 1988 EPRI dues. No capital costs are approved. In its next GRC Edison may again seek capitalization of tangible plant purchased in prior years, but such a request will be granted only with adequate proof that the plant is used and useful, meets RD&D capitalization guidelines, and has been properly depreciated into the GRC test year.

9. Other Revenue Requirement Issues

9.1 Revenue Credits

Revenue credits are applied against utility costs in determination of net revenue requirement to be included in rates.

9.1.1 Off-System Sales Revenues

Off-system sales are contract sales to other utilities, excluding sales for full or partial requirements customers. In D.90-12-021 the Commission approved a settlement between Edison and DRA for Edison's revenue requirement in attrition year 1991. The settlement included a provision that non-fuel revenues from off-system sales would be credited to Edison's ERAM account rather than included in rates on a forecast basis. (Fuel-related revenues are credited to the ECAC account, in accordance with FERC rules.) The Commission also referred the issue to this GRC. Edison has requested that non-fuel revenues continue to receive ERAM treatment, and DRA concurs. According to Edison, it retains an incentive to maximize off-system sales, to keep rates low. Although there was no testimony on incremental O&M expenses associated with off-system sales, in its opening brief Edison proposed that three mills per kWh be excluded from the ERAM credits, giving Edison a further incentive to maximize off-system sales.

We will allow continued ERAM treatment of non-fuel revenues from off-system sales, under two conditions. First, Edison shall continue to forecast off-system sales revenues in ECAC and GRC proceedings, so that the ERAM balancing rate can be reduced in anticipation of off-system sales revenues. Second, the ERAM credits shall not be reduced for incremental O&M costs. In Exhibit 84, Edison requested that the ratemaking treatment for off-system sales adopted in D.90-12-021 should be continued, and the settlement approved in D.90-12-021 contained no provision for Edison to retain incremental O&M expenses.

9.1.2 Account 456 - Miscellaneous Revenues

DRA recommended that the forecast of Edison's test year miscellaneous revenues be increased by $8 million, to include sales of obsolete materials and supplies, specifically non-depreciable materials and supplies. Edison argued that such an adjustment would be double counting of the same dollars, because proceeds from the sale of materials and supplies are booked to FERC Account 108, which increases book depreciation reserves and eventually lowers rate base. The record evidence on this issue is not absolutely clear, but DRA has not convinced us that the reduction to Account 456 is necessary.

FEA recommended that $6.313 million be adopted for test year miscellaneous revenues, based on recorded 1990 revenues and an Edison data response which indicated that such costs are normal and are expected to continue in 1991 and 1992. Edison responded that its estimate of $2.6 million, which was based on 1989 data, is more reasonable because the later data included nonrecurring revenues from insurance claim payments. The evidence[63] shows that Edison has given FEA one explanation and the Commission another explanation. We will adopt the average of recorded revenues in 1989 and 1990, adjusted to 1992 dollars for nonlabor escalation. The adopted amount is $4.713 million, which is $2.113 million more than Edison's estimate.

9.1.3 Other Revenues

Since 1989 Edison has read gas and electric meters for the City of Long Beach. In its GRC application Edison estimated test year revenues of $833,000 for this service. Based on later data, TURN recommended $1.444 million in revenues. Edison now accepts the higher figure.

Edison also conceded $2.27 million in incremental revenues for late payment charges, in response to a DRA recommendation.

To determine CPUC jurisdictional rates, Edison's revenue requirement must be allocated between retail customers, whose rates are regulated by this Commission, and wholesale customers, whose

63 Exhibit 424, page 23; and Tr. 25:2232.

rates are regulated by FERC. There are no disputes concerning the various cost allocation factors.

9.2 MAAC Projects

In D.87-12-066, Appendix A, the Commission approved MAAC procedures, including the identification of MAAC projects in GRCs. In D.91-04-070 the Commission authorized MAAC treatment for two capital projects, the California-Oregon Transmission Project (COTP) and installation of selective catalytic reduction (SCR) technology at Edison's Alamitos Generating Station, Unit 6 (Alamitos 6). On the last day of Phase 1 hearings Edison withdrew its request for the COTP project.[64] Edison estimated that the Alamitos 6 project will go into service at the end of 1993. In Exhibit 119 Edison proposed criteria for verifying when the project goes into service. Edison estimated the project will cost $55.970 million, with associated investment-related revenue requirement of $10.980 million and annual noninvestment-related (O&M) expenses of $61,387. Edison seeks the following relief:

1. Approval of the following in-service criteria: (1) when physical installation of the SCR system is complete, (2) when startup, commission, testing, and calibration of all critical elements of the system have been completed, and (3) when operation and maintenance of the system has been turned over to Edison's Power Supply Department.

2. Recovery of $61,387 in non-investment-related costs (plus franchise fees and uncollectibles).

3. Approval of $10.980 million as the revenue requirement for investment-related costs, and inclusion of 75% of this amount in

64 Tr. 56:5706.

interim rates, to be credited to the MAAC account for Alamitos 6.

4. Authority to file an advice letter on the in-service date, effective on that date, to include Alamitos 6 in Edison's MAAC tariff.

5. Authority to file a second advice letter implementing interim rates at the time of the next regularly scheduled base rate or ECAC rate change following the in-service date.

6. Authority to file, within six months of the in-service date, an application seeking base rate recovery of the costs of the project, including reasonableness of capital costs and amortization of MAAC account balances.

DRA agreed to Edison's proposed MAAC treatment for Alamitos 6, except that Edison should not be allowed additional O&M expenses. According to DRA, O&M expenses are included in test year estimates and should not receive special treatment in attrition years.

We will approve Edison's proposed MAAC treatment for Alamitos 6, except that: (1) incremental non-investment-related costs shall not be authorized, (2) interim rates shall be $0.00011 per kWh, based on the adopted sales forecast, and (3) interim rates shall be reduced by 5% annually to reflect the reduction of revenue requirement as the asset is depreciated.

9.3 Attrition

Edison and DRA dispute five issues relating to attrition adjustments in 1993 and 1994.

9.3.1 Plant Additions

In D.82-12-055[65] the Commission authorized Edison to adjust its attrition year plant additions based on seven years of

65 10 Cal. PUC 2d 155, 275 (1982).

recorded data for plant additions per additional customer, excluding major plant additions. In GRCs since then Edison has computed yearly plant additions per additional customer and averaged the seven values, with adjustments for inflation. In this GRC DRA proposed a new technique. DRA recommended that the total plant additions over seven years be divided by total customer additions, replacing Edison's method of averaging the ratios from individual years. DRA claimed that its technique: (1) was adopted in the 1991 attrition settlement, (2) will smooth out data fluctuations, and (3) will reduce anticipated attrition year plant additions in this GRC. Edison opposed DRA's scheme, and recommended retaining its own method. We accept DRA's argument about smoothing of data, which the Commission cited in D.82-12-055, and we will adopt DRA's technique.

9.3.2 Small NOx Reduction Projects

In addition to trended plant additions, Edison requested an extra $2.932 million in 1993 and $14.098 million in 1994 for 13 small NOx reduction projects. DRA opposed these costs, claiming that they are included in other estimates of projects costing less than $10 million. Edison believes DRA's recommendation is unfair, because Edison's estimates of projects under $10 million have been adjusted to exclude several identifiable projects.

The attrition mechanism is intended to allow for reasonable escalation of costs in the absence of full annual review. There are two ways for utilities to add to attrition year rate base: in separate applications for major projects, and through trending of historical data for smaller projects. As the Commission stated in D.82-12-055, in response to Edison's request to include budgeted plant additions in attrition year rate base, "Edison's approach would, in effect, require calculation of an additional set of test year results." We will not expand the scope of GRCs by allowing individual plant additions into attrition year rate base. This policy was affirmed in D.85-12-076.[66]

9.3.3 Nuclear Design Documentation

Edison also requested special attrition year plant additions for anticipated 1993 and 1994 deferred debits related to nuclear design documentation. We deny Edison's request, for the same reasons cited for small NOx reduction projects.

9.3.4 Health Care Escalation

Both Edison and DRA proposed that Edison be allowed to increase health care revenue requirement using an escalation factor higher than conventional labor and nonlabor escalation factors. However, the parties disputed the appropriate 1993 and 1994 values of the health care escalation factor.

Although we agree with the parties that health care costs are increasing faster than other costs, we will not approve a separate health care escalation factor because the parties' analyses are fundamentally flawed. The escalation factors used for labor and nonlabor attrition are derived from data bases which include health care costs. If health care escalation is to be authorized separately, then the labor and nonlabor escalation factors for other costs must be adjusted to exclude the effects of health care escalation, both in weighting for health care costs and removal of health care escalation from published price indexes. Neither Edison nor DRA has made the necessary adjustments, and we suspect that those adjustments might be cumbersome. If Edison wishes to revisit this issue in its next GRC, it should keep in mind that simplicity of escalation calculations is one of the basic virtues of the attrition mechanism.

66 Conclusion of Law 2; 19 Cal. PUC 2d 453, 477 (1985).

9.3.5 DSM Capital Additions

Edison requested rate base additions of about $2.6 million in 1993 and 1994 for increased DSM efforts. We will deny these increases, consistent with adopted attrition policy.

9.4 Summary of Earnings

Summary of earnings tables for test year 1992 are shown in Appendix D to this decision. Attrition year adjustments are shown in Appendix E, without adjustments for Cost Containment. DRA's summary of earnings tables[67] show line item adjustments for salary reductions, an information services adjustment, Cost Containment, and productivity. Where applicable, adopted adjustments in these areas have been absorbed into individual expense functions in Appendix D.

The principal outcome of Phase 1 is authorization of test year 1992 revenue requirement. When A.90-12-018 was filed, Edison requested an increase in ALBRR of $173.141 million for Phase 1, effective January 1, 1992. At the time briefs were filed Edison had revised the requested increase to $191.364 million. DRA recommended a revenue requirement $274.099 million below Edison's request, resulting in a net reduction in ALBRR of $82.735 million. In this decision Edison's ALBRR is increased by $53.346 million, relative to the ALBRR effective December 31, 1991.

9.5 Coordination with Other Proceedings

Rate revisions will not be ordered in Phase 1 of this GRC. The revenue requirement revisions ordered in this decision will be consolidated with revisions from other proceedings, including ECAC and cost of capital changes, and rates will be set in A.91-05-050, Edison's current ECAC application.

67 Exhibit 205, Chapter 14.

Edison presented preliminary revenue consolidation exhibits in its Phase 1 testimony. These tables have been useful to the Commission. Edison should file similar information in future GRCs, ECAC applications, and other proceedings in which rates are revised, to demonstrate to all parties where specific revenue requirement revisions fit in with revisions in other proceedings.

Edison's next GRC should be filed for a 1995 test year, based on recorded operations through 1992. The GRC should be processed according to the Rate Case Plan.

9.6 Capital Budgeting

In Phase 1 we have seen three separate instances of capital budgeting by Edison in advance of justification of individual capital projects: (1) refueling costs at SONGS, (2) plant additions by APS at Palo Verde, and (3) information services. We are concerned that Edison may be imprudently authorizing capital projects without adequate justification. Certainly some capital projects are needed to replace retired plant and might be justified by historical trends, but even then the exact plant items may not be replaced, because retirements present utility managers with opportunities to plan for future expansion. Of greater concern are expansions of function (e.g., information services) or utility capacity (e.g., transmission and distribution substations).

In its next GRC Edison should present testimony on its management policies and practices for planning and approval of capital projects, including: budgeting processes; distinction among replacement, expansion, and new functions; timing of approvals and project justification; and comparison with the budgeting policies and practices of unregulated corporations.

9.7 Devers-Palo Verde Work Orders

In 1985 Edison filed A.85-12-012, seeking a CPCN for a proposed second Devers-Palo Verde transmission line (DPV2). In that proceeding ALJ Randolph Wu issued a ruling stating that the Commission may consider a disallowance of certain regulatory costs incurred for "work which was performed but is now useless due to concealment of [a] 1985 letter agreement" between Edison and LADWP. The application is still open, and Edison estimates project completion in 1997.

DRA recommended in this proceeding that the Commission close the DPV2 work orders as a penalty for concealment of the letter agreement. Edison argued that A.85-12-012 is the appropriate proceeding to consider disallowance of DPV2 costs. We concur with Edison.

9.8 HVDC Expansion Project

In A.89-10-001 the Commission is considering the costs of Edison's high voltage direct current (HVDC) transmission line expansion project. According to DRA, Edison has stipulated to an $80.0 million cost cap, and test year capital costs of $5.3 million will bring Edison's total expenditures up to $77.7 million, close to the cap. DRA requested that in future proceedings Edison be required to identify all additional expenditures, to ensure that the cap is not exceeded. Although Edison has listed base rate revenue requirement for the HVDC expansion project in its revenue consolidation testimony in Phase 1, it is uncertain whether A.89-10-001 will be resolved prior to the GRC test year. A settlement was filed in February 1991.

We accept DRA's recommendation. Edison should report total project capital costs in its next GRC.

9.9 Hazardous Waste Management

In its last GRC Edison requested and was authorized $11.7 million for a program to replace underground storage tanks.[68] That program is still underway. Edison also requested

68 D.87-12-066, 26 Cal. PUC 2d 392, 458 (1987).

base rate funding for a program to mitigate hazardous residues at sites of manufactured gas plants, which operated from the late 1880s to the early 1920s. Edison acquired several of these local companies and eventually incurred substantial cleanup liabilities.

The Commission did not approve Edison's original request. Instead, Edison entered into a stipulation with PSD to establish memorandum account treatment for hazardous wastes. The Commission approved the stipulation, and Edison is now authorized to record hazardous waste expenditures in memorandum accounts for eventual recovery in rates following reasonableness reviews. The accounts are established by advice filings, in accordance with rules adopted by the Commission.[69]

In this proceeding Edison requested that its memorandum account authority for hazardous waste costs be continued, and that similar authority be granted for expenses to comply with pending storm water discharge regulations promulgated by the U.S. Environmental Protection Agency. DRA agreed to Edison's request because accurate forecasts of these expenses are not possible.

Memorandum account treatment of these costs is reasonable, and we will extend Edison's existing authority through the end of 1994. However, we note that hazardous waste cleanup costs are liabilities associated with ownership of utility property, and the costs are recovered entirely from ratepayers. In future review of gain-on-sale of utility properties we will inspect the balance of risks and rewards with hazardous wastes in mind.

10. Marginal Costs

Most marginal cost issues have been resolved in uncontested additional joint testimony by the parties that submitted testimony on marginal costs. Two issues should be

69 D.87-12-066, 26 Cal. PUC 2d 392, 458 (1987); D.89-01-039, 27 Cal. PUC 2d 576 (1989); D.89-09-019.

resolved in Phase 1: gas price method, and the need for a transformer cost study. Several other issues have been resolved by the parties but may be revisited in Edison's next GRC.

10.1 Joint Testimony on Marginal Costs

Six of the seven parties that served testimony on marginal costs also served "Joint Testimony on Marginal Costs," later received as Exhibit 113. The joint parties are Edison, DRA, TURN, California Large Energy Consumers Association (CLECA), FEA, and IU. In Exhibit 113 the parties agreed to a method to calculate marginal costs. Actual marginal energy costs will depend on natural gas prices adopted in Edison's ECAC proceedings, and all marginal costs will depend on operating expenses adopted in Phase 1. No party contested the joint method.

The major elements of the joint method are: (1) calculation of marginal transmission costs from an Edison regression analysis, (2) retention of current costing periods, (3) assignment of line transformers to customer costs, not distribution costs, (4) annual cost escalation of 5%, (5) use of DRA's marginal cost incremental energy rates (IERs) during this GRC cycle, (6) determination of gas prices in ECAC proceedings, (7) deferral of disputes over six-year averaging of marginal costs to Edison's next GRC, (8) deferral of disputes over treatment of gas demand charges to Edison's next GRC, (9) revision of adopted marginal costs to reflect Phase 1 resolution of various operating expenses (plant loading, working capital, and O&M costs), and (10) resolution of methodological issues in GRCs.

We will adopt the joint marginal cost method in Exhibit 113 without revision. The CACD has applied the method to adopted Phase 1 operating expenses, using TURN's value for City of Long Beach meter reading revenues and the example gas price in Exhibit 113 of $3.35 per decatherm. The resulting marginal costs are shown in Appendix F to this decision. However, one important clarification is necessary, concerning the method for calculating gas price.

10.2 Gas Price Method

The parties disputed how to calculate the marginal gas price used as an input to marginal energy costs. Edison believes that an average marginal cost from all gas sources is appropriate, to be determined in Phase 2 of this GRC because parties have not had adequate opportunity to address the issue. CLECA and IU believe the issue should be resolved in Phase 1, and that the method used in Edison's last ECAC proceeding should be retained. Under that method, construction of marginal gas price has three elements: (1) the price of gas delivered to the relevant interstate pipeline, typically a spot market price, (2) interstate transportation costs, and (3) intrastate transportation costs for service by Southern California Gas Company (SoCalGas). TURN believes that this issue should be resolved in ECAC proceedings.

We agree with IU on construction of the gas price used to calculate marginal energy costs. Exhibit 113 clearly states that methodological issues should be resolved in GRCs, and in this GRC Phase 1 is the forum for marginal cost issues. The basic choice in determining marginal gas cost is between California border prices, supported by CLECA and IU, and prices from all sources, supported by Edison. No party has presented testimony on weighting of marginal costs by the likelihood that individual gas sources will be the marginal supply, similar to production cost modeling of electric utility dispatching operations. We are left with interstate supply as the best available proxy for a marginal gas source. We agree with IU that interstate supply is a better proxy than an average of all sources. For this GRC cycle, we adopt the three-part construction of marginal gas costs suggested by IU. ECAC proceedings are the proper forum for determination of the three cost elements, but not of the method.

10.3 Deferred Issues

The parties have agreed to defer to Edison's next GRC several marginal cost issues: DRA's proposed six-year averaging of marginal costs, assignment of line transformer costs to customer or distribution costs, and inclusion of gas demand charges in marginal gas costs. We also defer further consideration of the appropriate marginal source of gas supply.

We note that the adopted method includes a present value calculation over 30 years, at a 12% discount rate and 5% inflation. The resultant marginal costs are very sensitive to these rates. For example, a 1% change in either rate can change marginal generation costs by about 5%, and marginal transmission and distribution costs by 10% or more. Increasing the discount rate raises marginal costs, but increasing the inflation rate reduces marginal costs. Because the discount and the inflation rates work in opposite directions, marginal costs are particularly sensitive to the difference between the discount rate and the inflation rate. In future proceedings parties should pay careful attention to assumptions about the difference between the two rates.

TURN has agreed to include line transformer costs in marginal customer costs, but it proposed that the marginal cost of transformers should be the lowest available capital cost. According to TURN, any additional cost is justified by increased energy efficiency, not by the marginal cost of either serving a customer or building a distribution system. There is no information available to test the impacts of this division of costs. TURN asked that the Commission require Edison to perform a study which would separate the minimum marginal costs for the customer or distribution function from costs incurred to reduce overall system expenses. Edison opposed this request, arguing that it is unnecessary and would provide no useful information because TURN's theory is faulty. We will not judge the merits of the theory in this GRC, but we will order Edison to perform the study. A report will be due in six months.

10.4 Marginal Street Light Costs

Edison, DRA, and the California City-County Street Light Association (CAL-SLA) served a "Joint Exhibit on Marginal Street Light Costs," later received as Exhibit 117. These parties agreed on a method to calculate marginal street light costs, to be updated for adopted plant loading, working capital, and O&M costs. Marginal street light costs do not depend on gas prices. No party contested the joint exhibit.

We will adopt the joint marginal cost method in Exhibit 117 without revision. Adopted marginal costs are shown in Appendix F to this decision.

10.5 IER Workshops

In D.87-12-066 the Commission ordered that in future GRCs and ECAC proceedings CACD should convene workshops to determine data sets to be used in construction of marginal cost IERs.[70] In this GRC CACD discussed the need for workshops with Edison and DRA, and proposed, by letter to all parties, to forego the workshops. No party requested workshops, and the active parties later stipulated to DRA's values of the IERs.

We will revise the previous order on IER workshops, to allow CACD to determine the need and scheduling of future workshops.

10.6 Allocation of Costs

During hearings the FEA raised the issue of whether production and transmission costs should be allocated to customer classes on the basis of Edison's monthly system peak.[71] This cost

70 Ordering Paragraph 36, 26 Cal. PUC 2d 392, 615 (1987).

71 Edison opening brief, p. 298.

allocation apparently relates to construction of average costs used in the Phase 2 revenue allocation process, but FEA did not provide testimony or further argument on the issue. No Commission action is required.

10.7 Resource Plan

The primary purpose of adopting a resource plan in a GRC is to calculate the utility's energy reliability index (ERI),[72] which is then used in evaluation of cost-effectiveness of DSM programs and in revenue allocation and rate design.

Edison originally filed a resource plan from Spring 1989, but during hearings it introduced a "barebones" resource plan from the CEC's ER90, which was published in October 1990. From that resource plan Edison calculated a six-year average ERI of 0.63.

DRA also used the ER90 barebones resource plan to derive a six-year average ERI of 0.63, but before making its calculation DRA removed from the resource plan about 100 MWe of forecasted QF and self-generation resources. This adjustment is not large enough to change the ERI value, but DRA argued that forecasted QFs and self-generation should be removed because the adopted resource plan may have policy implications in subsequent Commission proceedings. DRA believes its adjustment is consistent with D.90-03-060,[73] in which the Commission excluded forecasted QFs and self-generation from barebones resource plans.

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72 The ERI is a measure of the value of generation capacity in calculations of marginal costs. When a utility needs capacity to increase reliability of service, its ERI is 1.0, and marginal costs include all marginal generation costs. As capacity is added and reserve margin increases, the value of incremental capacity declines, and the ERI drops below 1.0. Marginal generation costs are then discounted by the reduced values of the ERI.

73 36 Cal. PUC 2d 2, 61 (1990), Conclusions of Law 4 and 5.

DRA also developed a "fully built" resource plan, in the event a fully built ERI is used in Phase 2 of this proceeding to determine nonfirm rate incentives.

We will adopt the ER90 barebones resource plan for purposes of this GRC, with DRA's recommended adjustment to remove forecasted QFs and self-generation. The adjustment is consistent with inclusion of only existing and committed resources in barebones resource plans. We also adopt DRA's fully built resource plan, but we reserve judgment on the propriety of its use for rate design or any other purpose. We will adopt the undisputed six-year average ERI of 0.63, but other calculations of ERI may be required in the future. We do not conclude that a six-year average is appropriate in every circumstance.

11. Demand-Side Management

Edison's requested test year revenue requirement for DSM activities is $167.130 million (in 1992 dollars), including income taxes, franchise fees, and uncollectibles. This revenue requirement is separated into five major areas, as shown in Table 6 below:

TABLE 6

Requested Test Year DSM Revenue Requirement
(Thousands of 1992 Dollars)

$ 17,024	Amortization of 1990 and 1991 costs
68,124	Shared savings programs
27,946	Modified expense programs
53,762	Expense programs
+ 274	Capitalized transformers
$167,130	Total

These amounts are almost three times Edison's DSM expenditures authorized for test year 1988, although expenditures had been higher in prior years. Briefly, the amortization revenue requirement is for amortization of 1990 and 1991 expenditures approved in D.90-08-068.[74] Shared savings programs are those for which Edison shareholders would receive incentive payments based on program energy savings. Modified expense programs would earn incentive payments based on Edison's expense levels, rather than achieved savings. Expense programs are those recovered in rates as ordinary expenses, without incentive payments. The capitalized program is for purchase of energy-efficient amorphous core transformers, as described in Chapter 6.

Authorized DSM expenses, shown in column (I) on Table 7, total $127.526 million in 1988 dollars, more than twice the DSM expenses authorized in test year 1988 and 40% higher than 1990 expenses authorized in D.90-08-068.

11.1 Policy

At the time of Phase 1 hearings, the active DSM parties anticipated a Commission rulemaking on DSM policy, but uncertainty over the timing of the rulemaking encouraged testimony on policy issues. On August 7, 1991 the Commission opened R.91-08-003 and I.91-08-002 (DSM rulemaking), a consolidated proceeding on rules and procedures governing utility DSM activities. That proceeding considers policy principles that will cover all energy utilities, not only Edison.

In Phase 1 of this GRC Edison presented ten policy principles[75] for the Commission's adoption. Many parties objected to Edison's principles, especially principles relating to air quality benefits, fuel substitution goals, and customer retention activities. DRA testified to 60 policy principles that it calls funding, evaluation, and implementation principles (FEIP). These FEIP are similar to principles recommended by DRA in recent GRCs

74 37 Cal. PUC 2d 346 (1990).

75 Exhibit 98, Chapter 1.

for PG&E and SoCalGas. In its analysis of Edison's requested program costs, DRA generally proposed two levels of funding: one level with conditions, and a reduced level without conditions. Some of the conditions for higher funding relate to DRA's proposed FEIP.

We will not adopt Edison's ten proposed policy principles. In general, they are too vague and they inadequately define limits to utility DSM activities. Further consideration of DSM policy is deferred to the DSM rulemaking. This GRC is not the proper forum for adopting general DSM policy principles.

We likewise defer DRA's FEIP to the DSM rulemaking, but with the note that DRA's principles may be overly complicated and too restrictive to account for changing circumstances. We used these words in GRC decisions for PG&E[76] and SoCalGas,[77] and they serve in this proceeding as well.

We will, however, adopt interim DSM policies as necessary to authorize recovery of Edison's DSM program expenditures in rates. In areas where DRA has recommended conditional approval of program expenses and where we do not reach policy conclusions, we assume that DRA's recommendations are for the unconditional expense levels.

Several parties, most notably CLECA and IU, showed concern over the impact of Phase 1 issues on rate reductions offered for interruptible service. The setting of interruptible rates belongs in Phase 2 of the GRC, but there is some question about the forum for review of a bidding program for interruptible service. We find that the DSM rulemaking is the proper forum,

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76 D.89-12-057; 34 Cal. PUC 2d 199, 399 (1989).

77 D.90-01-016; 35 Cal. PUC 2d 80, 119 (1990).

rather than Phase 2, because policy choices will affect all utilities.

11.2 Programs

Edison's proposed program funding levels, DRA's recommendations, and adopted DSM expenses are shown in Table 7 on the following pages. Table entries are in 1988 dollars.

COM/PME/mds

TABLE 7
TEST YEAR DEMAND-SIDE MANAGEMENT PROGRAMS
(EXPENSES IN THOUSANDS OF 1988 DOLLARS)

Line No.	Program Category and Measure: (A)	Requested Amounts: Shared Savings (B)	Modified Expensed (C)	Expensed (D)	Total Requested (E)	DRA Total (w/o cond) (F)		Adopted Amounts: Shared Savings (G)	Perform. Adder (H)	Expensed (I)	Total (J)	
	RESIDENTIAL CONSERVATION:											
1	New construction (Welcome Home)	$10,348	50	50	$10,348	$5,641		$10,348	50	30	$10,348	1/
2	Direct Assistance	10,226	2,186	0	12,411	12,411		10,226	0	2,186	12,411	
	Energy Management Incentives:											
3	Appl Eff Incentives	7,774	0	0	7,774	4,068	2/	5,774	0	2,000	7,774	3/
4	Appliance Loan Admin	0	0	32	32	32		0	0	32	32	
5	Weatherization Loan Admin	0	0	14	14	14		0	0	14	14	
6	Compact Fluorescent Bulbs	2,015	0	0	2,015	1,080	2/	2,015	0	0	2,015	4/
7	Energy Mgmt Incentives Subtotal	9,789	0	46	9,835	5,194		7,789	0	2,046	9,835	
8	Residential Energy Mgmt Services	0	5,576	0	5,576	4,800		0	4,800	0	4,800	5/
	Residential Information Programs:											
9	Outreach	0	0	649	649			0	0	449	449	
10	Action Line	0	0	550	550			0	0	550	550	
11	Outdoor Security Lighting	0	0	251	251	1,450		0	0	0	0	
12	Res Information Programs Subtotal	0	0	1,450	1,450	1,450		0	0	999	999	
13	RESIDENTIAL CONSERVATION TOTAL	30,362	7,762	1,496	39,620	29,496		28,362	4,800	5,231	38,393	
	LOAD MANAGEMENT:											
14	A/C Cycling	0	0	2,015	2,015	1,000		0	0	1,500	1,500	
15	RESIDENTIAL CONS/LOAD MGMT TOTL	30,362	7,762	3,512	41,636	30,496		28,362	4,800	6,731	39,893	
	NONRESIDENTIAL CONSERVATION:											
	Information Programs:											
16	Major Account Programs	0	0	1,211	1,211			0	0	1,211	1,211	
17	Energy Outreach	0	0	426	426	1,636		0	0	426	426	
18	Nonres Information Programs Subtotal	0	0	1,636	1,636	1,636		0	0	1,636	1,636	
	Energy Management Services											
19	Large Commercial Audits	0	1,936	0	1,936			0	1,936	0	1,936	
20	Small/Medium Commercial Audits	0	3,810	0	3,810	5,746		0	3,810	0	3,810	
21	Large Industrial Audits	0	2,776	0	2,776			0	2,776	0	2,776	
22	Small/Medium Industrial Audits	0	2,322	0	2,322	5,098		0	2,322	0	2,322	
23	Agricultural Pump Tests	0	3,154	0	3,154	2,078		0	3,154	0	3,154	
24	Subtotal: Energy Managment Services	0	14,000	0	14,000	12,922		0	14,000	0	14,000	
	Energy Managemernt Incentives											
25	Hardware Rebates	16,709	0	0	16,709	11,336		16,709	0	0	16,709	
26	A/C Maintenance	474	0	0	474	3,243		474	0	0	474	
27	Small Commerical Lighting	3,387	0	0	3,387	1,161		3,387	0	0	3,387	
28	Subtotal: Energy Management Incentives	20,570	0	0	20,570	15,740		20,570	0	0	20,570	6/
	New Construction:				0							
29	Design for Excellence	11,464	0	0	11,464	5,118		11,464	0	0	11,464	
30	Outdoor Security Lighting	0	686	0	686	0	7/	0	0	0	0	
31	New Construction Subtotal	11,464	686	0	12,150	5,118		11,464	0	0	11,464	
32	Misc. Conservation	0	0	1,000	1,000	0		0	0	0	0	
33	NONRES CONSERVATION TOTAL	32,034	14,686	2,636	49,356	35,416		32,034	14,000	1,636	47,672	
	NONRESIDENTIAL LOAD MGMT:											
34	Interruptible Cooperatives	0	0	1,881	1,881	941		0	0	1,881	1,881	8/
35	A/C Cycling	0	0	224	224	100		0	0	224	224	
36	Off Peak Cooling/TES	0	0	3,980	3,980	0		0	0	3,980	3,980	9/
37	Ag Interruptible Rates	0	0	387	387	387		0	0	387	387	10/
38	NONRESIDENTIAL LOAD MGMT TOTAL	0	0	6,472	6,472	1,428		0	0	6,472	6,472	

TABLE 7
TEST YEAR DEMAND-SIDE MANAGEMENT PROGRAMS
(EXPENSES IN THOUSANDS OF 1988 DOLLARS)

Line No.	Program Category and Measure: (A)	Requested Amounts: Shared Savings (B)	Modified Expensed (C)	Expensed (D)	Total Requested (E)	DRA Total (w/o cond) (F)	Adopted Amounts: Shared Savings (G)	Perform. Adder (H)	Expensed (I)	Total (J)	
39	NONRES CONS/LOAD MGMT TOTAL	32,034	14,686	9,110	55,830	36,846	32,034	14,000	8,110	54,144	
40	TOTAL CONSERVATION/LOAD MGMT	62,396	22,448	12,622	97,465	67,343	60,396	18,800	14,841	94,037	
	FUEL SUBSTITUTION:										
41	Commercial Cooking	0	0	414	414	|	0	0	414	414	11/
42	Induction Melting	0	0	438	438	|	0	0	438	438	
43	Infrared Heating	0	0	652	652	|	0	0	652	652	
44	Dielectric Heating	0	0	634	634	0	0	0	634	634	12/
45	TOTAL FUEL SUBSTITUTION	0	0	2,137	2,137	0	0	0	2,137	2,137	
	LOAD BUILDING:										
46	Dry Cleaners	0	0	366	366	|	0	0	366	366	
47	Ozone Water Treatment	0	0	319	319	|	0	0	319	319	
48	Central Cooling Facilities	0	0	868	868	|	0	0	868	868	
49	Clean Air Coatings	0	0	1,076	1,076	0	0	0	1,076	1,076	
50	TOTAL LOAD BUILDING	0	0	2,629	2,629	0	0	0	2,629	2,629	
	LOAD RETENTION:										
51	Bypass Coordination	0	0	2,969	2,969	|	0	0	2,969	2,969	
52	Low NOx Burners	0	0	351	351	|	0	0	351	351	
53	Emerging Technologies	0	0	4,685	4,685	0	0	0	4,685	4,685	
54	TOTAL LOAD RETENTION	0	0	8,004	8,004	0	0	0	8,004	8,004	
	MEASUREMENT AND EVALUATION:										
	Program Evaluation										
55	Program Evaluation	0	0	946	946	946	0	0	946	946	
56	Weather Stations	0	0	237	237	237	0	0	237	237	
57	Program Tracking Systems	0	0	394	394	394	0	0	394	394	
58	EM Report Systems	0	0	557	557	557	0	0	557	557	
59	SIC Coding	0	0	722	722	722	0	0	722	722	
60	Electric Vehicles	0	0	2,000	2,000	2,000	0	0	2,000	2,000	
61	CPUC Compliance	0	0	693	693	693	0	0	693	693	
62	Goal Optimization	0	0	498	498	498	0	0	498	498	
63	Persistence Studies	0	0	46	46	46	0	0	46	46	
64	Cost Effectiveness	0	0	204	204	204	0	0	204	204	
65	Program Evaluation Subtotal	0	0	6,296	6,296	6,296	0	0	6,296	6,296	
	Load Metering										
66	Appliance End Use	0	0	449	449	449	0	0	449	449	
67	Class Load Research	0	0	1,167	1,167	1,167	0	0	1,167	1,167	
68	Residential Appliance End Use	0	0	438	438	438	0	0	438	438	
69	Load Metering Subtotal	0	0	2,053	2,053	2,053	0	0	2,053	2,053	
	Customer Surveys										
70	Test Market Evaluation	0	0	306	306	158	0	0	306	306	
71	Customer Focused Data	0	0	471	471	471	0	0	471	471	
72	Potential Savings Studies	0	0	611	611	611	0	0	611	611	
73	Attitude Studies	0	0	680	680	680	0	0	680	680	
74	Saturation Studies	0	0	673	673	673	0	0	673	673	
75	End Use Acceptance	0	0	506	506	506	0	0	506	506	
76	Customer Surveys Subtotal	0	0	3,247	3,247	3,098	0	0	3,247	3,247	
	New Technology Assessment										
77	Study Evaluation C/I Technology	0	0	2,241	2,241	1,816	0	0	2,241	2,241	
78	Study Evaluation Res Technology	0	0	1,026	1,026	601	0	0	1,026	1,026	
79	New Technology Load Assessment	0	0	513	513	513	0	0	513	513	
80	New Technology Assessment Subtotal	0	0	3,780	3,780	2,930	0	0	3,780	3,780	
81	TOTAL MEASUREMENT & EVALUATION	0	0	15,376	15,376	14,377	0	0	15,376	15,376	

TABLE 7
TEST YEAR DEMAND-SIDE MANAGEMENT PROGRAMS
(EXPENSES IN THOUSANDS OF 1988 DOLLARS)

Line No.	Program Category and Measure: (A)	Requested Amounts: Shared Savings (B)	Modified Expensed (C)	Expensed (D)	Total Requested (E)	DRA Total (w/o cond) (F)	Adopted Amounts: Shared Savings (G)	Perform. Adder (H)	Expensed (I)	Total (J)
	MANAGEMENT/SUPERVISION:									
82	Management/Supervision	0	0	3,486	3,486	3,486	0	0	3,486	3,486
83	Program Support	0	0	1,857	1,857	1,857	0	0	1,857	1,857
84	Non Conservation A&G	0	0	27	27	27	0	0	0	0
85	MGMT/SUPERVISION SUBTOTAL	0	0	5,370	5,370	5,370	0	0	5,343	5,343
86	NON CONSERVATION TOTAL	0	0	33,518	33,518	19,746	0	0	33,489	33,489
87	DSM PROGRAM TOTAL (1988 DOLLARS)	$62,396	$22,446	$46,138	$130,981	$87,089	$60,396	$18,800	$48,330	$127,526
88	Escalation 1988 to 1992 DOLLARS				13,822					13,335
89	DSM PROGRAM TOTAL (1992 DOLLARS)				144,803					140,860
90	Carryover of 1990/91 Amortized Programs				12,806					12,606
91	GRAND TOTAL (1992 DOLLARS)				$157,209					$153,467

1/ General advertising prohibited.
2/ Prorated from total of $3,146, from Exhibit 275.
3/ Includes $2,000 of expenses, instead of shared savings for Golden Carrot Program.
4/ Maximum administration and advertising 30% of total.
5/ Cost-effectiveness report required in 3/93 DSM Annual Report.
6/ No incentive limit per account.
7/ Included in EM incentives.
8/ All customer bill credits to be credited to ERAM account.
9/ Limit incentives to installations with TRC >1.0.
10/ General advertising prohibited.
11/ For existing electric equipment only.
12/ Reporting requirement in 3/93 DSM Annual Report.

11.2.1 Residential Energy Conservation

Edison plans nine programs in this area. The first is a shared savings program called Welcome Home, aimed at new residential construction and budgeted at $10.348 million. DRA recommended $5.641 million. TURN pointed out that the program's high administrative costs are due in part to general advertising within the budget. We will authorize Edison's requested $10.348 million, but without ratepayer funding of any program costs for general advertising.

The second program covers direct assistance to qualified low-income customers, senior citizens, the permanently handicapped, and customers who do not speak English. Edison's proposed program budget is $12.411 million, split into $10.226 million of shared savings expenses, and $2.186 million of modified expenses. DRA recommended full ratepayer funding of these amounts. James Hodges, representing three community-based organizations (East Los Angeles Community Union, Maravilla Foundation, and Veterans in Community Service; or CBOs), was generally satisfied with Edison's assistance to low-income customers, but recommended that no shareholder incentives be awarded until at least 75% of weatherization goals are met. The CBOs also recommended that funding for residential infiltration control, or "indoor air pollution," be scaled back. We will approve Edison's proposed $12.411 million, but $600,000 of the $700,000 budgeted for infiltration control should be shifted to basic weatherization. We will not adopt a shared savings trigger, but we repeat the CBOs' reminder that Edison should offer direct assistance only to eligible customers.

The third program is for appliance efficiency incentives, budgeted at $7.774 million of shared savings expenses. DRA recommended $4.088 million. TURN recommended that a program measure for leveraged funding of refrigerator manufacturers, budgeted at $2 million and known in Phase 1 hearings as the "Golden Carrot" program, be authorized only subject to refund. The funds would be used to subsidize manufacturers or provide customer rebates, in order to induce market penetration of superefficient refrigerators. The consortium of utilities involved is not yet complete, but funds would not be expended until the refrigerators are actually shipped into Edison's service territory as a result of the program. NRDC enthusiastically supported the Golden Carrot program. We will authorize $7.774 million for the appliance efficiency program, but we will move Golden Carrot funding from shared savings to ordinary expenses because program plans are unsettled.

Fourth, Edison seeks $46,000 in ordinary expenses to administer existing conservation and weatherization loans. No new loans have been made since 1986. No party opposed the request, and we will grant it.

The fifth program is budgeted at $2.015 million of shared savings expenses for promotion of compact fluorescent light bulbs. DRA recommended $1.060 million. TURN noted that the program total resource cost (TRC) ratio of 1.18 is relatively low, due to high administrative costs. TURN and NRDC agree that the program should be expanded to promote more bulbs for the same administrative costs, increasing cost-effectiveness. TURN recommended that the Commission limit administrative and advertising expenses to 30% of program costs. We will approve Edison's requested funding and adopt TURN's 30% limitation.

Edison's sixth residential program is for energy management services, budgeted at $5.576 million of modified expenses. The proposed services are on-site energy audits and mail-in audits using forms that customers send to Edison for analysis. DRA recommended $4.800 million, the 1989 expense level for residential audits, because no new programs are proposed. DRA also suggested that Edison should conduct a cost-effectiveness study of test year residential audits and should report the results in Edison's March 1993 DSM annual report. We will adopt DRA's recommended $4.800 million funding level, without shareholder incentives, and order Edison to make the proposed study.

Edison's seventh program is called Residential Outreach, one of three informational programs that would be funded as ordinary expenses. DRA agreed with Edison's funding levels for all three information programs. Residential Outreach is budgeted at $649,000. TURN recommended a $200,000 reduction for expenses intended to promote seasonal and time-of-use (TOU) rates because no customers have enrolled on these schedules since they were authorized in 1987. We accept TURN's reduction and will authorize $449,000.

In its eighth program Edison requested $550,000 to fund a toll-free telephone line for conservation information. No party contested this amount, but DRA recommended that Edison consider making advertising for the toll-free line less general and more specific about programs available to customers. We will approve the $550,000.

The ninth and final program is budgeted at $251,000 to promote new and retrofit outdoor security lighting. TURN opposed funding of this program because it is aimed at load building, not energy efficiency. We will deny funding of both residential and nonresidential outdoor security lighting.

<u>11.2.2 Residential Load Management</u>

Edison has budgeted $2.015 million of ordinary expenses to continue a program of residential air conditioner cycling. DRA recommended funding of $1.000 million because customer additions to the program have been lower than anticipated and Edison plans no new promotions of the program. We will compromise and approve funding of $1.500 million.

<u>11.2.3 Nonresidential Energy Conservation</u>

Edison proposed 13 programs in this area. The first is a major accounts information program budgeted at $1.211 million of ordinary expenses. No party contested this amount, and we will approve it. The second program, also informational and aimed at trade associations, is called Energy Outreach, budgeted at $428,000 of ordinary expenses. Again, no party contested this amount, and we will approve it.

The next two programs are for energy audits or surveys of large commercial and medium or small commercial customers. Edison proposed modified expense treatment for all energy audit programs. Edison requested $1.938 million for large customer audits and $3.810 million for medium and small customer audits. DRA recommended $5.748 million for the two programs combined. We will approve Edison's requested amounts, without shareholder incentives. Modified expense incentives are discussed in Section 11.5.

The fifth and sixth programs are energy surveys for large industrial and medium or small industrial customers. Edison requested $2.776 million for large customer audits and $2.322 million for medium and small customer audits. No party opposed these amounts, and we will approve them, without shareholder incentives.

The seventh program is budgeted at $3.154 million of modified expenses for agricultural pump testing, a program in place since 1911. DRA recommended $2.076 million. We will approve Edison's requested $3.154 million, without shareholder incentives.

The next three programs are for energy management incentives, for which Edison requested shared savings expenses. The eighth program is for hardware rebates, budgeted at $16.710 million. The ninth is a new program to promote air conditioning maintenance, budgeted at $474,000. The tenth program is for small commercial lighting, budgeted at $3.387 million. The subtotal of requested funding for the three incentive programs is $20.570 million. DRA recommended $15.740 million, equal to the 1991 funding level. We will approve Edison's requested funding.

Edison at first proposed an incentive cap of $100,000 per account for energy management incentives, but the California Energy

Coalition (Coalition) and NRDC opposed the limit, arguing that it would preempt huge savings opportunities and contradict the requirements of PU Code $ 701.1. In its opening brief Edison agreed to abandon the cap. We agree with the Coalition and NRDC that an incentive cap might limit conservation achievements, but equity considerations tend to support a cap. We will allow Edison to award incentives without a cap, but we refer the policy issue to the DSM rulemaking.

Edison's eleventh nonresidential program is a shared savings plan called "Design for Excellence," a collection of incentives for nonresidential new building construction budgeted at $11.464 million. DRA recommended funding at the 1991 level of $5.118 million. We will approve Edison's requested funding.

The twelfth request is for $686,000 in modified expenses for nonresidential outdoor security lighting. Consistent with our denial of funding for residential security lighting, we will deny Edison's request.

Edison's thirteenth request is for $1.000 million of ordinary expenses for miscellaneous conservation activities. DRA recommended no funding. TURN recommended that the Commission deny $700,000 of the funding, but order Edison to use $300,000 to start a refrigerator recycling program. We will deny Edison's request altogether.

11.2.4 Nonresidential Load Management

Edison requested ordinary expense funding of four nonresidential load management programs. The first is budgeted at $1.881 million, for program expenses and bill credits for energy cooperatives, which are customer groups that agree to reduce their aggregate demand upon notice from Edison. DRA recommended funding of 50% of Edison's request, because Edison expects the growth rate of new cooperatives to decline in the test year. We will approve Edison's request.

The second load management program is for commercial and industrial air conditioner cycling, budgeted at $224,000. DRA recommended $100,000. The current funding level is $118,000. We will approve Edison's request.

The third program is for off-peak cooling, also known as thermal energy storage, budgeted at $3.980 million. DRA recommended no funding, unless individual measures show TRC ratios greater than 1.0 and incentive payments are capped at $50 per kW. DRA's opposition is due to a low TRC ratio for the program as a whole and high incentive payments, which can exceed $250 per kW. We will approve the requested $3.980 million in funding, with the condition that no incentive payments be made to projects for which the forecast TRC ratio is less than 1.0. We will not adopt DRA's payment cap. The adopted test year marginal generation, transmission, and distribution costs are approximately $82, $33, and $53 per kW per year, respectively, and thermal energy storage projects will endure for many years. An incentive payment limit of $50 per kW is not justified.

Edison's fourth request is for $387,000 to promote agricultural interruptible service. This is a new program of direct load control by Edison. No party opposed the request, and we will approve it, with the condition that none of the funds are used for general advertising.

11.2.5 Fuel Substitution, Load Retention, Load Building: General Policy

Edison requests funding of expenses in three categories, each of which consists of several new programs, none of which were a part of the Collaborative proceeding. The categories and corresponding funding levels are: Fuel Substitution, $2.137 million; Load Building, $2.629 million; and Load Retention, $8.004 million.

We authorize Edison's funding request for each category as discussed below. We have relegated to the DSM rulemaking further consideration of the appropriate character and content of programs in the areas of fuel substitution, load retention, and load building. We have noted earlier in this decision our goal, stated in R.91-08-003/I.91-08-002, that utilities should design load building programs so as to avoid frustrating the encouragement of energy efficiency and energy conservation. We believe this holds equally for load retention programs, and we have stated a similar concern with respect to fuel substitution.[78]

Therefore, our authorization of these programs in this GRC is on a limited basis only. We preclude Edison from shifting any monies from other DSM programs into these fuel substitution, load retention, and load building programs. Moreover, we preclude the shifting of monies among these three programs. Specifically, for example, while Edison may shift monies between infrared heating and dialetic heating under the umbrella of Fuel Substitution, it may not shift monies from any Fuel Substitution program to one under the category of Load Retention or Load Building. In addition, Edison shall not earn any shareholder incentives on these programs.

We remind Edison that it has the burden of proof in its next GRC of showing that a request to continue or expand these programs should be granted. To that end, we are persuaded that certain of DRA's reporting recommendations are well-taken. We will require Edison to monitor implementation of these programs carefully and to submit, in its next GRC, detailed assessments of economic, environmental, and any other claimed benefits, should it seek funding for fuel substitution, load retention, and load building programs at that time. We also require Edison to include in its next GRC filing detailed environmental evaluations of the impact of the technologies it chooses to promote, including the

78 R.91-08-033, I.91-08-002, Appendix A, p.5 (mimeo)

repercussion of increased load on Edison's system. These studies should clearly identify and explain any assumptions made.

Finally, as DRA has recommended, we require Edison to include in its March 1993 DSM annual report a table that will indicate the source and amount of funding for CTAC. In that document Edison should also report on the cost effectiveness of its fuel substitution programs.

11.2.5.1 Fuel Substitution

Edison requested funding of four fuel substitution programs, all ordinary expenses. The first program would retrofit electric commercial cooking equipment, and is budgeted at $414,000. CEC supported the program. Parties opposing funding include DRA, TURN, SoCalGas, and IU. We will approve Edison's requested funding based on the claimed efficiency benefits. In Exhibit 98 Edison stated that the program is targeted for customers "with older, inefficient electric cooklines and AQMD compliance problems."

The second program is budgeted at $438,000 for electric induction melting as a substitute for gas or inefficient electric furnaces. CEC recommended $200,000 for a pilot program, but other active parties opposed funding. SoCalGas in particular opposed funding, arguing that the program is not cost-effective. Edison calculated a TRC ratio of 1.04, assuming gas equipment of average efficiency, but SoCalGas believes the appropriate comparison is with very efficient gas equipment, which would reduce the TRC ratio below 1.0. We will approve funding of this program. Although the program shows marginal cost effectiveness, we are convinced that a pilot program such as this has the potential for greater future efficiency and environmental benefits.

The third program is for infrared curing or drying operations as substitutes for conventional thermal baking, budgeted at $652,000. Again, CEC recommended $200,000 for a pilot study and other parties opposed funding. Edison's estimated TRC ratio is 1.13. We will approve funding of this program given its estimated cost-effectiveness and the potential for reducing customer energy costs as well as meeting air quality regulations.

The fourth program, budgeted at $634,000, is for dielectric heating in baking, rubber, and pharmaceutical operations. This is a fuel substitution program, but Edison's estimated TRC ratio is a relatively high 2.56, because dielectric heating has the potential for high source energy efficiency. CEC recommended full funding of the program, but other parties opposed ratepayer funding. We will approve Edison's requested funding because of the program's high potential for cost-effectiveness.

<u>11.2.5.2 Load Retention</u>

Edison requested funding of three load retention programs, all as ordinary expenses. The first program is for bypass coordination, budgeted at $2.969 million. This is essentially a management effort to track customers considering bypass, to administer special sales contracts, to survey bypass potential, and to investigate methods to mitigate bypass activity. Every active customer group opposed the program. The California Cogeneration Council opposed all funding of load retention programs, arguing that Edison's programs are biased against cogeneration. CEC supported $500,000 of funding to develop and distribute an information package to customers considering bypass. Edison's proposed program includes bypass due to economic and environmental factors. We will approve funding for this program. We view this and other load retention programs as serving a useful function in providing information to potential bypass customers thereby avoiding underutilization of utility physical plant, deterioration of system load factor, thereby causing remaining customers to incur higher costs. If it requests continued funding for this program in its next general rate case, Edison will have a strong burden of proof to show that these funds are delivering economic and/or environmental benefits to ratepayers.

Edison's second load retention effort would provide customers with information on low NOx burner technology. The program is budgeted at $351,000. No other party supported the program. SoCalGas vigorously opposed funding, arguing that gas utilities are better equipped to provide customers with gas burner information. We disagree. Edison has a long history in the development of low NOx burner technology for use in its generating plants. In the continuing effort to address the NOx emission problem in the Los Angeles basin, every opportunity for technology transfer in this area should be explored. We will approve funding for this limited program. In its next GRC Edison is required to make a showing that these expenditures are cost-effective if it continues to request funding for this program.

The third program is for "Emerging Technologies," budgeted at $4.685 million. Due to potential loss of customers induced by strict air quality regulations, Edison would examine technologies which are not yet established and ready for fully developed programs, and apply the technologies to customer needs. No other party supported this program, but CEC recommended redirection of $2 million to a measurement and evaluation program to assess new technologies. TURN characterized the Emerging Technologies program as a placeholder for technologies that may or may not emerge. In reviewing Edison's discription, this program appears to be more accurately characterized as an RD&D program rather than a DSM program. That aside, this program can serve as a useful vehicle in disseminating information on technologies designed to address customer energy efficiency concerns and air emission problems. Shortening the time between when these technologies are demonstrated in the laboratory and when they can be applied in the market is an essential aspect of responding to increasing air quality regulations. We will approve funding for this program. Again, we emphasize that Edison bears the burden of proving in its next general rate case that the expenditure of these funds are cost-effective if it requests continued funding for this program.

11.2.5.3 Load Building

Edison requested funding of four load building programs, all as ordinary expenses. Generally, no other party supported funding of any program. CEC expressed a particular concern that load building efforts would present customers with unbalanced information that would favor electro-technologies over other resources.

The first program is budgeted at $366,000 and would inform dry cleaners about ventless equipment that would reduce volatile organic compound emissions. The program would retain load by preventing environmental bypass, and allow these customers to remain economically viable and still comply with future SCAQMD regulations. We will approve ratepayer funding for this pilot program. Edison is required in its next general rate case to show that the expenditure of these funds are cost-effective from an overall ratepayer perspective if continued funding of this program is to be requested.

The second program, budgeted at $319,000, would inform customers with large air conditioning loads about ozone water treatment systems as replacements for typical chlorine treatment systems. This is also an environmental bypass program aimed at retaining load on the system to the benefit of all customers. We will approve ratepayer funding for this pilot program. Again, we reiterate the requirement that Edision in its next general rate case show that this program is a cost-effective use of ratepayer funds.

The third program would help customers optimize the energy efficiency of electric chillers, as customers replace chiller systems or replace chlorofluorocarbon (CFC) refrigerants with other working fluids, in response to air quality regulations. According to Edison, 92% of the central cooling facilities market uses electric chillers. The program budget is $868,000. CEC opposed the program, but recommended funding of $100,000 for an informational program on CFC refrigerant replacement. Other parties opposed ratepayer funding. We will approve Edison's request based on the energy conservation characteristics of the program. We expect a showing of cost-effectiveness by Edison if continued funding of this program is requested.

The fourth program would allow testing of coating products and processes. Coatings for customer products would be tested at Edison's CTAC facility, in search of processes that would comply with new air quality regulations. The program budget is $1.076 million. We agree with Edison that coating technologies have a role in air quality management. The introduction of this technology will also have significant energy conservation characteristics through reduced HVAC requirements and elimination of auxiliary fans and motors used in conventional drying. We will approve ratepayer funding of the program. In future funding requests for this program, Edison will have the burden of showing that ratepayer funding is cost-effective.

11.2.6 Measurement and Evaluation Expenses

Edison has requested ordinary expense funding of $15.376 million for 22 measurement and evaluation programs. DRA contested $1.000 million of this amount, in the general area of new technology assessment. CEC recommended an additional $3.669 million in funding, including $2.000 million redirected from Edison's load retention request, and suggested revisions to nine of Edison's programs (e.g., use of focus groups, and a "1% tax" for statewide measurements directed by CEC).

During hearings Edison, DRA, and CEC expressed willingness to work cooperatively to develop measurement and evaluation plans. In D.90-08-068[79] the Commission anticipated more uniform DSM programs among utilities. That consistency is particularly important to measurement and evaluation of programs.

79 37 Cal. PUC 2d 346, 366 (1990).

We expect Edison to participate with DRA, CEC, and other utilities in development of consensus measurement and evaluation techniques and studies. As discussed elsewhere in this chapter, further consideration of measurement and evaluation issues is deferred to the DSM rulemaking.

It would be unproductive for the Commission to scrutinize all of the measurement and evaluation details contested on the record in Phase 1. Instead, we will adopt Edison's requested funding and defer the details to the DSM rulemaking. The adopted expense level is a reasonable compromise of the funding recommendations of the active parties.

11.3 Fund Shifting

In its 1988 GRC, Edison was ordered to seek Commission approval by advice filing to shift funds among its three major program areas (residential conservation, nonresidential conservation, and load management) or to shift more than $2.5 million in funds within a program area.[81] This rule was modified somewhat in response to an Edison request in late 1991.[82] Edison has proposed to increase the level to $10 million. DRA opposed Edison's request, and supported several FEIP related to fund shifting and restriction of funding for fuel substitution, load building, and customer retention programs.

We will allow Edison to continue its previous fund shifting rules, rather than adopt new rules proposed by Edison or DRA. We will reinstate the $2.5 million limit ordered in D.87-12-066, but relaxed in Resolution E-3244. We will allow no increased ratepayer funding of fuel substitution, load building, and customer retention programs beyond levels authorized in this

81 D.87-12-066, 26 Cal. PUC 2d 392, 480 (1987).

82 Resolution E-3244, approved October 23, 1991.

decision and will not permit the shifting of funds among the program categories. Additional expenditures are not prohibited by rule, but they may not be recovered from ratepayers. We clarify that the $2.5 million limit is the cumulative limit per GRC cycle, but it is not a spending cap in any sense. Above the limit, advice filings are required.

Edison may shift funds away from or into DSM programs eligible for incentive payments, but it should adjust its energy savings and incentive payment targets accordingly, with adequate support for those changes in an advice filing.

Edison and NRDC supported authority for Edison to increase its DSM funding levels for attrition years 1993 and 1994. We are reluctant to grant that authority, considering that test year expenditures are substantially increased over current levels, but we will allow increases under these circumstances: (1) increases will be allowed only by separate application, (2) increased funding must be justified by increased demand for utility programs, as measured by participation rates relative to forecast participation rates, and (3) shareholder incentive targets--both forecast savings and incentive payments--must be adjusted to reflect the increased funding.

11.4 Measurement and Evaluation

Edison proposed that its DSM accomplishments be measured as the products of forecast energy and capacity savings per unit installed, times recorded installation numbers. Other parties, notably the CEC, urged that Edison increase its efforts to measure unit savings. We encourage further measurement effort, as part of the DSM rulemaking.

There is an open issue concerning measurement of savings per installed unit. Should these measurements be updated in the authorization of incentive payments? The parties have agreed that incentive payments should be based on actual, not forecast, installations. Improved measurements of unit savings should obviously be used in future forecasts of savings, but use of updated information to determine incentive payments is more complicated. CEC argued that the improved measurements should be used because they reflect real energy savings. DRA believes that use of forecast unit savings will avoid endless litigation of incentive payments as utilities attempt to support higher unit savings in situations which would produce higher incentive payments.

We defer this general question to the DSM rulemaking. In the interim, Edison should base incentive payments on its own forecasts of unit savings. We appreciate CEC's claim that incentive payments should be based on real net savings, but forecast savings are an adequate proxy until policy issues are resolved outside this GRC.

Parties to the DSM rulemaking should recognize a useful distinction made by CEC. In measuring DSM savings, it may be convenient to distinguish building envelope modifications from industrial process modifications. The envelope measures are more amenable to metered energy savings, because building loads are relatively stable over time or can be adjusted for weather impacts. Process savings depend on plant output, for which data are proprietary. Process measures may be more amenable to other forms of post-installation measurement.

We emphasize to Edison that test year savings used to calculate incentive payments must be substantiated. Unit savings should be adequately referenced to savings forecasts from this proceeding, and records of customer installations should be verifiable and available to other parties.

<u>11.5 Incentive Mechanisms</u>

In its GRC application, Edison requested DSM incentive payments based on the amortization scheme authorized in D.90-08-068, plus modified expense incentives based on a percentage of program expenses. Confronted with vigorous opposition from other parties, Edison agreed to change its amortization scheme to a program of incentives based on shared energy savings achieved by eligible Edison programs. DRA and CEC supported shared savings incentives, but they disagree on the level of ratepayer support for incentives and on the details of the shared savings mechanism. TURN supported an incentive system by which authorized rate of return would be adjusted according to DSM accomplishments. TURN also suggested that the Commission order Edison to establish in its next GRC that any adopted shareholder incentives have led to cost-effective program savings.

TURN reminds us that incentive programs which benefit shareholders without their making capital investments are not permanent. We have previously found that incentives should be funded by ratepayers, but incentives may be necessary only because the marketplace for energy efficiency in California--including regulatory influences--is obstructed from free operation, and the prices of demand-side alternatives to supply are not eliciting efficient market responses. Incentives help overcome those obstacles, but this situation may not endure indefinitely. As well, it has not been demonstrated that all market responses are caused by utility efforts. We expect this subject to be studied in the CACD report ordered in D.90-08-068, Ordering Paragraph 1.h. The Commission's intent is to promote DSM such that incremental customer savings in response to incremental utility efforts are cost-effective. In its next GRC, Edison should present testimony on the long run cost-effectiveness of utility efforts, with specific attention to marketplace obstacles and progress toward overcoming them.

We will authorize an interim shared savings incentive program for Edison, subject to revisions ordered in the DSM rulemaking. The interim shared savings program resembles private industry programs in that Edison, the service provider, earns the provider is paid by all ratepayers, not the customer receiving the services. The need for ratepayer support should be considered in the DSM rulemaking.

Earned incentive payments can be amortized over three years, as Edison requested, in order to confine ratemaking complications to a single GRC cycle.

We will deny Edison's proposed modified expense incentives, because they would be based directly on expenses, not energy savings. The connection between utility expenses and energy savings makes even shared savings dependent on utility expenses, but incentives with no dependence on achievements are unreasonable, pending further consideration in the DSM rulemaking.[83]

11.5.1 Adopted Shared Savings Mechanism

Edison proposed a shareholder incentive of 15% of life cycle program savings induced by eight eligible programs, once 75% of forecast savings are achieved. The payments would be awarded as credits to Edison's ERAM account, amortized over three years following the program year. The basis for the 15% would be life cycle energy savings, less the average of utility and total costs.

DRA proposed the same 15% percentage and the same basis, but DRA recommended a benefit cap related to supply-side earnings, penalties for savings below 50% of forecast savings, and program-by-program application of the formula.

CEC proposed no incentive caps, payments equal to 15% of savings less utility costs, and payments equal to 30% of savings for a pilot program based on measured savings.

We are unsatisfied with all of these approaches, because they include perverse incentives that accompany trigger levels of savings and because the proposed caps remove the utility incentive

83 R.91-08-003 and I.91-08-002, Appendix A, Proposed Policy Statement 18.

to pursue all cost-effective DSM opportunities. Edison's 75% trigger gives the utility a great incentive to overestimate savings when annual savings are just below 75%. Expressed another way, the incremental incentive at precisely 75% savings is extremely high, and extremely high incentives invite selfish responses. Edison's flat 15% earnings rate from 75% of forecast savings onward does not allow for the penalties anticipated by PU Code § 746(b), and it does allow for very high earnings if savings greatly exceed forecast savings. We are attracted to DRA's theory of setting DSM rewards commensurate with supply side rewards, but DRA's scheme is unreasonably complicated.

To avoid extremely high incremental incentives in the relationship between rewards and achieved net benefits, we will order an S-shaped function which will offer: (1) penalties for very low net benefits, (2) a zero-intercept for net benefits, beyond which Edison will begin to accrue rewards, (3) low incremental incentive rates (per unit of recorded net benefits as a percentage of forecasted net benefits) at very low and very high net benefits, (4) greatly increased incentive rates near forecast net benefits, and (5) smooth transitions between the different net benefits regions. See Appendix G for the sketchs of the S-shaped incentive functions we adopt for several energy efficiency programs.

The S-shaped curve, or incentive function, is linear for savings below 75% of forecast and above 125% of forecast, and parabolic from 75% to 125%. It is derived--using very elementary calculus--from specification of the incremental incentive rates in each savings region. As indicated from the S-curve graphs in Appendix G, Edison will have greatly increased incentives in the 75% to 125% range of net benefits. The decreased incentive rate for very high net benefits is a compromise between a payment cap and continuation of incentives at a constant, high rate.

An S-shaped incentive function will be adopted as a shared savings mechanism for the following utility programs: Residential Appliance Efficiency Incentives, Commercial Energy Efficiency Incentives,[84] Industrial Energy Efficiency Incentives, Agricultural Energy Efficiency Incentives, Residential New Construction and Nonresidential New Construction and non-mandatory Direct Assistance. Energy Management Services (EM Services) Information programs, as well as mandatory Direct Assistance Programs, will not receive shared savings treatment. Mandatory Direct Assistance and Information programs shall receive simple expense treatment, consistent with other utilities' programs, and as recommended by DRA.

<u>11.5.1a Performance Adder Programs</u>

Both DRA and Edison agree that EM Services should receive Performance Adder treatment. The Performance Adder mechanism is similar to the "cost plus" mechanism we approved for PG&E on similar programs whereby Edison receives incentive earnings based on a fixed percentage of applicable program expenditures provided minimum goals are met.

DRA and Edison proposed an incentive of 5% of program expenses on EM Services, with the exception of Residential EM Services. DRA and Edison disagree on the incentive percentage for Residential EM Services. DRA argues that Edison has not demonstrated historical energy savings under Residential EM Services as have other utilities who have received a 5% incentive. DRA, therefore, recommends a 2% incentive on Residential EM Services for the rate case period.

We adopt Edison's and DRA's recommendation of 5% for EM Services aside from Residential. We adopt a 2% incentive for

84 We do not endorse pre-specified savings with respect to customized rebates as they are incorporated in the Edison resource benefit data we use herein.

Residential EM Services. Further, we adopt a minimum performance goal of 75% of total units as shown in Edison's Exhibit 123 for EM Services.

11.5.2 Risk and Symmetry

Several parties testified to the risks of demand and supply-side alternatives, and the symmetry of rewards and penalties under DSM incentive mechanisms. Edison testified that for the same increment of capacity, demand-side risk is higher than supply-side risk because demand reduction depends on customer actions outside of utility control. Other parties argue that demand-side programs incorporate portfolio diversity, which makes them less risky than supply.

We need not resolve this debate, but we note that Edison ignores identification of the parties which must bear either demand-side or supply-side risks. Under incentive ratemaking for DSM programs, shareholders contribute no capital. They face the performance risks that achieved savings will not reach a minimum level, but they do not face the capital risks of supply-side investment. If risks and rewards were balanced, the expected value of DSM incentives would be zero, but for DSM programs we have temporarily abandoned the conventional risk-reward balance. The adopted incentives formula is symmetric, but it is symmetric around a par or target value of incentive payments, not around zero. It is reasonable to depart from the risk-reward standard in order to overcome DSM market imperfections, but we must continue to inspect this premise in the future.

11.5.3 Basis for Incentive Payments

For shared savings programs, the parties have proposed various definitions of net program benefits, which then become a basis for determining incentive payments. The parties have defined the following quantities: (1) incentive basis, IB, (2) total resource benefits, TRB, (3) utility administrative costs, UAC, (4) utility incentive costs, UIC, and (5) customer or participant costs, PC. Edison and DRA proposed that the incentive basis should be total resource benefits less the average of utility and total costs, where utility costs = UAC + UIC, and total costs = UAC + PC. This results in an incentive basis = total benefits - UAC - 0.5 x UIC - 0.5 x PC. CEC proposed a basis of total benefits less only utility costs.

CEC's basis is theoretically correct, because net societal benefits do not depend on the incentive amount, which is a transfer payment from the utility to the participant. However, Edison and DRA are correct that including customer incentive costs encourages Edison to minimize incentives paid to customers. We will adopt an interim incentive basis as recommended by Edison and DRA. With the adoption of this incentive basis, we do not prejudge any determination on incentive bases which may be made in the DSM rulemaking.

We agree with DRA that the incentive basis will not, by itself, encourage Edison to minimize administration costs or customer incentives. However, we believe that averaging total costs and utility costs will encourage Edison to more carefully consider tradeoffs between maximizing benefits and minimizing costs.

<u>11.5.4 Incentive Targets</u>

The adopted incentive functions for shared savings are determined by a net savings target equal to the forecast life cycle benefits ($) for eligible programs, and an incentive payment target. DRA recommended that shareholder incentives have a cap based on equivalent shareholder earnings from supply-side investments. We have rejected the cap, but we wish to pursue the long-term goal that utility managers should choose fairly between demand-side and supply-side resources. Therefore, interim incentive payments will be based on a target of Edison's pre-tax rate of return on eligible program expenses for each individual program, as if Edison had invested the same amount of capital in supply-side resources. We recognize that for the same expenditures, DSM programs should produce more total benefits than supply-side resources, because benefit-cost ratios must exceed one, but we have other concerns: (1) actual incremental energy savings may be lower than actual measured savings due to "free riders," and (2) the market for energy efficiency is not absolutely unresponsive to energy prices, so that to a certain extent shareholder incentives are unnecessary. Considering these factors, setting an incentive payment target based on utility program expenses is a reasonable compromise.

Referring to the curve Functions in Appendix G, the net benefits target is 100% of forecast energy savings. The incentive payment target, or shareholder earnings at 100% of forecast net benefits, is utility expenses (UAC+UIC) for eligible programs times authorized rate of return.

__11.5.5 Procedures__

To establish the test year incentive targets for each program to which shared savings are applicable, we must set S-curve functions for each program. The data necessary to set these S-curves are utility administration costs, UAC, utility incentive costs, UIC, participant costs, PC, and the resource benefits for each program. We have previously adopted utility total costs which are a summation of UAC and UIC.

For the purposes of setting the S-curves, we will use Edison's forecasted resource benefits and participant costs. However, we do not adopt the underlying assumptions e.g. marginal costs, savings/measure, measure life, and net-to-gross, in the Edison numbers. Nevertheless, adopted numbers for each of the underlying assumptions are necessary for the calculation of total resource costs or TRCs for each measure under all shared savings programs.

We, therefore, will order Edison to file an advice letter with CACD which contains values for all data necessary to calculate total resource costs for each shared savings measure adopted here. The Commission fully expects Edison to justify any Commission adoped assumptions used for total resource costs through aggressive measurement and evaluation during the rate case period.

The incentive payments for shared savings are a function of the actual achieved net benefits divided by the net benefits used to fix the curves. The curve itself is fixed using the inputs shown in the graphs contained in Appendix G. For each program, the associated incentive rate is different, but common to all functions are the following: (1) a penalty for achievements below 50% of net benefits, (2) a 50% bandwidth between the minimum and maximum incentive levels, and (3) an adopted target incentive based on a 10.59% of utility costs.

With this mechanism in place, Edison's incentive earnings are driven by their level of achievement in that the effective incentive rate increases continuously as net benefits increase. This is unlike PG&E's incentive which incorporates a fixed percentage of net benefits after a minimum level is achieved.

11.5.6 Summary

We have adopted an incentive function--the relationship between achieved savings and shareholder incentive payments--which mitigates perverse incentives and tends to confine payments to a reasonable range. Adopted interim definitions for program benefits, incentive basis, and incentive targets are reasonable compromises of the parties' recommendations and practical considerations. The adopted incentive function is algebraically complex, but it is theoretically sound and can be easily calculated using spreadsheets. Revisions to the adopted shared savings mechanism may be considered in the current DSM rulemaking.

The adopted incentives are consistent with the requirements of PU Code $ 746. The interim incentive program does not complete the Commission's obligations under PU Code $ 746 because it applies only to Edison, but it is a step in the right direction.

11.6 PU Code $ 701.1

After Edison prepared and served its DSM testimony, the Legislature enacted PU Code $ 701.1, which states:

> "The Legislature further finds and declares that, in addition to any appropriate investments in energy production, electrical and natural gas utilities should seek to exploit all practicable and cost-effective conservation and improvements in the efficiency of energy use and distribution that offer equivalent or better system reliability, and which are not being exploited by any other entity."

In response to the new code section and encouragement from NRDC, the sponsor of the legislation, Edison has agreed to withdraw its customer incentive caps and to seek to expand its DSM programs where cost-effective opportunities are identified. Edison believes that $ 701.1 requires that Edison have the ability to incur DSM expenditures over and above its funding request in this GRC. However, Edison testified that $ 701.1 does not require ratepayer funding of every dollar needed to achieve DSM goals.

NRDC's proposal for spending flexibility, endorsed by Edison, would allow DSM funding above GRC levels when justified by customer demand, "subject to the same prudency reviews that all Edison's efficiency programs received."[85] NRDC testified that none of the DSM opportunities addressed by Edison's programs are exploited by other entities.

TURN opposed the increased funding sought by Edison and NRDC. TURN argued that $ 701.1 must take its place among other PU Code sections which require just and reasonable rates and other

85 Exhibit 406, p. 2.

ratepayer protections. TURN pointed to legislative intent that § 701.1 should preserve regulatory agency flexibility in planning for both generating facilities and energy efficiency and conservation programs.[86] NRDC seems to favor retrospective prudency reviews of Edison's DSM expenses.[87] TURN believes such review would be illegal, because there is no mechanism in place to avoid retroactive ratemaking problems.

We agree with TURN that § 701.1 must be considered "in addition to other ratepayer protection objectives," as stated in § 701.1 itself. We also acknowledge that prudency reviews of DSM expenses are now and should continue to be made on a forecast basis. The practicality test in § 701.1 includes the practicality of Commission review of DSM funding by ratepayers. We have allowed increased DSM funding between GRC test years, but only after Commission review and upon a showing by Edison that there is a demand for increased funding. We have relied on NRDC's testimony in specifying the necessary utility showing of increased demand.

One § 701.1 limitation that remains untested is the extent of exploitation of conservation by other entities. NRDC believes that Edison's efforts do not duplicate the efforts of any other entity, but that notion is not supported by a factual record. The market imperfections that justify utility DSM programs are not absolute. Customers do take some conservation actions in response to energy prices and the workings of competitive markets. Market players are among the other entities specified by § 701.1, confirming Edison's conclusion that § 701.1 does not require ratepayer funding of every dollar needed to achieve all cost-effective energy conservation. There is no evidence on the record

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86 Report of the Senate Committee on Energy and Public Utilities on AB 3995, Attachment B to opening brief of TURN.

87 Tr. 31:3022-3023.

about pursuit of the same conservation opportunities by utilities and other entities.

We have substantially increased Edison's DSM expenses, eliminated incentive caps, and allowed increased DSM funding when it is justified by increased customer demand. These actions, along with authorization for rate recovery of reasonable DSM expenses, do not in any way hinder Edison from compliance with § 701.1.

11.7 Other DSM Topics

Commission review of Edison's DSM expenses has been hampered by inconsistent presentation and formatting of the evidence. DSM and RD&D programs are fundamentally different from conventional utility functions, and the FERC Uniform System of Accounts was not created with DSM in mind, but these are not valid excuses to depart from rigorous ratemaking accounting. In future GRCs all active parties should clearly identify and tabulate the programs they are discussing and categorizing. In its next GRC Edison should present a DSM comparison exhibit which sets forth the positions of all active DSM parties, not only Edison and the DRA. The exhibit should be served on Day 206 of the Rate Case Plan, concurrent with the joint comparison exhibit on revenue requirement issues.

TURN has recommended that the Commission limit A&G expenses--including advertising--to 30% of DSM program budgets. TURN suggested that general advertising costs have increasingly found their way into DSM budgets. Except for the compact fluorescent light bulb program, we will not adopt TURN's 30% limit. However, in its next GRC Edison should identify the A&G percentage for all proposed DSM programs, so that other parties and the Commission can quickly identify programs with higher than average A&G costs.

We will deny Edison's program-specific attrition year DSM funding requests. Existing formula adjustments for cost escalation apply to DSM expenses. The adopted test year expense level is a substantial increase over current authorized expenses, and Edison has not justified its requested exceptions to attrition escalation principles. As discussed earlier in this chapter, Edison can request further DSM funding by separate application.

Standard TRC calculations exclude the costs of incentives given to customers. From a societal perspective incentive payments are transfers, not costs, but the exclusion of incentive payments removes an incentive for utilities to control those payments. The TRC formula should be revisited in the DSM rulemaking.

12. Proposed Return on Equity Penalty

Edison and its affiliates are authorized to own up to 50% of QF projects which sell power to Edison. Since 1984 Edison has executed agreements with affiliated projects for more than 1500 MW of capacity, representing more than 40% of the QF generation purchased by Edison. Under Edison's holding company structure, affiliated QF transactions are made through the Mission Group and, primarily, Mission Energy Company (collectively, Mission Energy). DRA and other parties have raised disputes in several Commission proceedings concerning the transactions between Edison and its QF affiliates and the provision of information about those transactions.

12.1 Position of DRA

DRA has recommended that the Commission reduce Edison's ROE by 40 basis points (0.4%) for test year 1992, for failure to comply with Commission regulations regarding affiliated QFs. Half of this penalty, 20 basis points, is for Edison's repeated failure to provide information regarding affiliates to the Commission. An additional 20 basis point reduction is for Edison's anticompetitive favoritism of affiliated QFs over nonaffiliates. Taken together, the penalties would reduce test year revenue requirement by $35.9 million.

DRA believes that the problems of Edison's favoritism and failure to provide information are severe and have continued despite repeated warnings from the Commission. According to DRA, the penalties should be comparable to two penalties previously imposed by the Commission. In D.91107[88] the Commission penalized PG&E 20 basis points for failure to adequately pursue cogeneration opportunities. In D.82-12-055[89] the Commission penalized Edison 10 basis points for two years for failure to comply with Commission policies on pricing of QF contracts at full avoided costs.

12.1.1 Failure to Provide Information

The Commission examines the reasonableness of affiliate QF contracts in ECAC proceedings. In A.88-02-016, Edison's 1988 ECAC application, DRA reviewed a contract between Edison and KRCC. That review resulted in a Commission disallowance of $48.371 million in payments to KRCC due to Edison's imprudent actions in negotiating and executing the contract. (The amount of the disallowance is now in rehearing.) In A.89-05-064, Edison's 1989 ECAC application, DRA reviewed Edison contracts with Sycamore Cogeneration Company (Sycamore) and Watson Cogeneration Company, for its project at the ARCO Petroleum Products Company site (Arco-Watson). The 1989 ECAC reasonableness review is now in the hearing process before the Commission, consolidated with the reasonableness phases of A.90-06-001 and A.91-05-050.

DRA cited several examples of failures to provide information in the KRCC matter: (1) Edison's reluctance to respond to DRA's request for information on the affiliate partnership agreements, despite clear statement of DRA's and the Commission's rights in D.88-01-063,[90] in which the Commission authorized Edison's holding company structure; (2) Edison's deficient direct

88 2 Cal. PUC 2d 596, 726-730 (1979).

89 10 Cal. PUC 2d 155, 255-258 (1982).

90 27 Cal. PUC 2d 347, 374 (1988).

showing on the nonstandard provisions in the KRCC contract; (3) Edison's voluminous rebuttal showing, after DRA had revealed its concerns; (4) comments on evidentiary shortcomings by the ALJ and the assigned Commissioner; and (5) discussion language in D.90-09-088,[91] in which the KRCC disallowance was ordered.

DRA claimed that Edison's showing in its 1989 ECAC application failed the Commission's standards for utility testimony established in D.82-01-103:[92]

> "Applications for nonstandard contracts should clearly state all the differences between the contract and the standard offer, and identify all gains and costs for ratepayers. The application should further demonstrate why ratepayers should either be indifferent to or prefer the nonstandard contract over the standard contract."

DRA also cited findings in D.91-05-028,[93] in which the Commission denied approval of Edison's proposed merger with SDG&E:

> "322. As this record clearly demonstrates, despite SCEcorp's preexisting duties and the Commission's stated intention to construe the holding company conditions and its statutory authority in the broadest possible fashion, applicants have often failed timely or willingly to provide the information necessary for the Commission's reviews of affiliate transactions.
>
> "323. Applicant SCEcorp's reluctance to provide information as required by holding company decision Condition No. 1, and thereby satisfy its obligations under the regulatory compact struck in D.88-01-063, undercuts the notion that reliance should be placed on this

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91 37 Cal. PUC 2d 488 (1990).

92 8 Cal. PUC 2d 20, 31 and 83 (1982).

93 At mimeo. page 161.

mitigation vehicle even if it were modified in our decision today."

According to DRA, Edison has failed to comply with clear and direct orders to provide the information.

12.1.2 Favoritism and Anticompetitive Actions

To support its allegations of favoritism, DRA cited the same three nonstandard contracts with KRCC, Sycamore, and Arco-Watson, which together provide Edison with about 1000 MW of power. DRA claimed that Edison's favoritism causes ratepayers direct harm and is anticompetitive--in an economic sense--because it disadvantages nonaffiliate QFs. The latter problem could eventually harm ratepayers through reduced competition among all QFs. During hearings DRA admitted that its evidence of favoritism is circumstantial. DRA presented no written evidence of Edison policies or practices that show intent to favor affiliate QFs.

In D.90-09-088 the Commission made several findings that relate to favoritism to KRCC, but did not use that term explicitly: (1) Finding of Fact 129 refers to "acts of imprudency in the negotiation, execution, and administration of the KRCC agreement"; (2) Finding of Fact 132 refers to "management decisions... which did not adequately take into account the interests of its ratepayers as defined by the Commission's decisions and adopted standard offers"; and (3) Finding of Fact 138 refers to "actions taken by Edison which were at odds with specific Commission directives." DRA infers that those actions demonstrate favoritism because other large QF contracts do not have similar problems. D.90-09-088 made one additional finding that comes closer to a direct finding of favoritism. Finding of Fact 145 states:

> "By inference, it appears that Edison may have considered the interests of its QF affiliate before its ratepayers and other QFs."

DRA supported its claim of favoritism by comparing KRCC contract terms with terms in nonstandard contracts with nonaffiliates. The nonaffiliate contracts have stricter provisions. The favored terms offer KRCC: (1) the right to increase firm capacity at original contract prices, (2) capacity prices higher than standard offers, and (3) extended durations for heat rate floors and ceilings. DRA also claimed that negotiations for the KRCC contract showed conflict of interest, because Edison personnel could serve and hold fiduciary responsibilities for both Edison and Mission Energy.[94]

DRA made similar claims of favoritism relating to the Sycamore and Arco-Watson contracts, by comparison of various contract provisions with standard offers and nonaffiliate contracts. DRA claimed that Edison unfairly assisted Sycamore in its permit process before the CEC, including a request for confidentiality, and that Edison had a conflict of interest in the Arco-Watson negotiations because when the contract was approved Edison was considering affiliation with Arco-Watson.

Finally, DRA mentioned complaints of anticompetitive action raised by nonaffiliated QFs. DRA named Cal Energy as one active complainant, and cited a historical record of other transmission access disputes.

12.2 Position of Edison

Relative to the amount of revenue at stake, Edison contested the proposed ROE penalty more vigorously than any other issue. Edison hired outside counsel to litigate the issue, called five rebuttal witnesses, including a Senior Vice President, and filed briefs in two separate volumes.

Edison appended to those briefs three documents which are its pre-filed testimony in A.89-05-064, the 1989 ECAC application. DRA objected to any Commission notice of those documents. The documents are clearly additional testimony, not official documents

94 D.90-08-088; 37 Cal. PUC 2d 488, 576 (1990).

eligible for any form of notice. We have disregarded them in considering the proposed ROE penalty herein.

12.2.1 Prerequisites for an ROE Penalty

In its opening brief, Edison presented eight arguments in support of a finding that the prerequisites for imposition of an ROE penalty have not been met:

(1) Edison has not violated any clearly understood standards of behavior. There are several instances where the Commission has refused to impose penalties because the standards for utility behavior were not well defined.

(2) The Commission has not warned Edison of a possible penalty. DRA's cited warnings are from an ALJ and an assigned Commissioner, not the full Commission.

(3) There is no direct evidence of Edison intent to violate recognized standards. DRA's evidence is circumstantial and indicates Edison's intent to comply with Commission policies and directives.

(4) Other remedies are superior to penalties for encouraging Edison action. In its rebuttal testimony Edison offered to voluntarily restrict communications between Edison and affiliate employees, to distribute a semiannual report on affiliate contract negotiations, to disclose to DRA all documents which relate in any way to dealings with affiliate QFs, and to confer with DRA regarding information necessary to support its ECAC reasonableness reviews.

(5) The penalties lack any incentive or deterrent function. According to Edison, such penalties encourage Edison to seek pre-approval for its actions, burdening Edison and the Commission.

(6) DRA has failed to meet its burden of proof, which it must carry when it alleges violations of statutes, rules, orders, or tariffs.

(7) The ROE penalties would unfairly duplicate other adverse consequences sustained by Edison due to the KRCC and merger decisions. Edison believes that those Commission actions were taken in part due to Commission concern that Edison acted to favor affiliate QFs. Edison admits that separate penalties and disallowances are possible in response to the same behavior, but such duplication would be unfair in this instance.

(8) ROE penalties would cause "profound reverberations" in the financial community, inducing a perception of unfairness which could eventually increase Edison's cost of capital and harm ratepayers.

12.2.2 Evidence on Providing Information

Edison presented six arguments in opposition to a penalty for failure to provide information:

(1) DRA's testimony is confusing and conflicting. DRA has mixed evidence, testimony, and needs for information.

(2) There is no precedent or reason for a penalty for failure to carry the burden of proof.

(3) Other remedies are available and more effective. If Edison's direct showing in any proceeding is inadequate, DRA should file a motion to dismiss, or discovery can be used to obtain further information. If rebuttal testimony is excessive or should have been filed in a direct showing, DRA should file a motion to strike.

(4) Edison never intentionally omitted necessary information in the 1989 ECAC or merger proceedings. DRA's dissatisfaction is not evidence of intent to withhold information.

(5) DRA's examples of nondisclosure of information are anecdotal and fail to show a pattern or intent on Edison's part.

(6) Edison's management actions will mitigate further information problems.

12.2.3 Evidence on Favoritism

Edison presented seven arguments against a penalty for favoritism:

(1) Edison's policies and actions toward QFs have complied with Commission standards of conduct. Edison pursued affiliate QF contracts which were the best deals possible for ratepayers, consistent with Edison's obligations to promote QF development.

(2) DRA's standard for QF negotiations, which requires that all nonstandard contracts must be economically equal to standard offers, is impractical, harmful to ratepayers, and has not been endorsed by the Commission. According to Edison, DRA's policy requires that every significant contract provision offered to affiliate QFs must be made available to nonaffiliate QFs. This disclosure of terms that are offered during negotiations but might not be included in agreements exceeds Edison's obligations to bargain with QFs in good faith. Such disclosures would also harm ratepayers.

(3) The KRCC decision did not conclude that Edison had shown favoritism.

(4) DRA's review of affiliate QF contracts is incomplete. Contracts should be evaluated as a whole, and DRA has not done so, especially regarding nonstandard contracts with Northern Natural Resources, Operating Lease Services, and Midway-Sunset. Edison cited nonaffiliate contracts with terms more favorable to the QF than standard offers.

(5) DRA's contract administration examples do not indicate favoritism. Edison assisted nonaffiliate QFs before the CEC, and Arco-Watson was not an affiliate when its agreements were signed or extended.

(6) The Cal Energy complaint and other transmission access complaints should carry no weight.

(7) An ROE penalty is unnecessary because Edison has dealt with all QFs fairly and will act to further assure the Commission that no favoritism exists.

12.3 Discussion

There is ample precedent for Commission authority to penalize utilities by reduction of rate of return. The PG&E

penalty assessed in D.91107 and the Edison penalty assessed in D.82-12-055 are good examples.

DRA and Edison disputed whether the proposed ROE penalty is duplicative of other penalties. According to DRA, the KRCC disallowance was not a penalty and did not address the problems of favoritism and provision of information. ECAC reasonableness disallowances would be the same whether the QFs were affiliates or not, because ECAC disallowances reflect only unreasonable fuel-related expenses, not penalties for management failings. Edison witnesses held different views about penalties. Senior Vice President Charles McCarthy testified that capital cost reductions are properly called disallowances, but a large disallowance would have punitive character. Disallowances of unreasonable fuel-related expenses are generally not punitive in character. However, the KRCC disallowance and the merger denial were both penalties. Edison witness Robert Kendall testified that disallowance of any dollar amount by the Commission is not necessarily a penalty, but rejection of illegal requests would have penalty character. In his opinion the Commission's rejection of Edison's merger application has caused shareholder penalties, due to lost opportunities and the payment of merger transaction costs.

We agree with DRA's characterization of disallowances and penalties. Disallowances are denials of rate recovery for unreasonable costs, whether those costs are ordinary expenses, capital costs, or costs induced by unreasonable forecasts. Disallowances can result from explicit findings that costs are unreasonable or from failure to meet the burden of proof of reasonableness. Penalties are punishments for offenses or actions contrary to statute, order, rule, instruction, or express policy. Adverse consequences to shareholders do not by themselves make penalties out of Commission decisions or disallowances.

12.3.1 Obligation to Provide Information

There is ample evidence in this proceeding to support a finding that Edison has failed to follow Commission instructions on provision of information. In D.82-01-103 the Commission clearly set forth information requirements for nonstandard QF contracts. In presenting the KRCC, Sycamore, and Arco-Watson contracts before the Commission in its ECAC applications, Edison was obliged to "clearly state all the differences between the contract and the standard offers, and identify all gains and costs for ratepayers." DRA's discovery disputes and Edison's ECAC applications show that Edison has failed this standard. Findings of Fact 322 and 323 in the merger decision confirm Edison's failings. No further warnings by the Commission are required. The preponderance of evidence is adequate to find that Edison has failed to meet a clear standard of behavior. An ROE penalty for this failing would not unfairly duplicate the KRCC disallowance, and the Commission denial of Edison's proposed merger with SDG&E is not a penalty. The Commission should not and will not refuse to order justified penalties because of the financial community's anxiety about adverse consequences to shareholders. The financial impacts of any Commission decision are important, but our first responsibility is to ratepayers.

Despite these findings, we will not order an ROE penalty for failure to provide information, because a penalty is not the most effective remedy for the offending actions. In Commission applications, failure to provide information is fundamentally a failure to meet the burden of proof, and remedies directly related to burden of proof may be more appropriate. This notion is supported by the lack of precedent for such penalties, as Edison has noted.

Enforcement of Edison's obligations to provide information has tried our patience. It is not enough to characterize informational disputes as mere discovery differences, or to suggest motions to dismiss or motions to strike. The evidence of Edison's failings requires stronger medicine. In future ECAC reasonableness reviews, including the current A.89-05-064, if information disputes similar to those experienced in the KRCC and merger proceedings should be repeated, we suggest that DRA submit additional testimony on ECAC expenses during the review period as if the disputed affiliate QF contracts did not exist. Such testimony may rely on computer production cost models or other techniques. In this way the Commission may find reasonable only the lowest available replacement power costs, if Edison fails to meet its burden of proof for affiliate QF contracts. DRA should waste no more time extracting affiliate information from Edison.

12.3.2 Favoritism to Affiliate QFs

Regarding DRA's claim of affiliate QF favoritism, we have a different problem. An ROE penalty would be an appropriate response to favoritism, but the present record is inadequate to make the necessary findings of favoritism. Because the evidence of favoritism is circumstantial, we will in this instance require that favoritism be demonstrated in the negotiation, execution, or administration of more than one affiliate QF contract.

We disagree with Edison's arguments that no standards for affiliate QF transactions exist. The Commission has not endorsed the exact QF negotiating policy that DRA recommends, but standards for affiliate QF transactions are clear. In D.82-01-103[95] the Commission required assurance that affiliates should not receive special treatment:

> "The guiding principle for nonstandard contracts upon which applications should be based is that the contract terms, taking into account the associated risks, should not be more than

95 8 Cal. PUC 2d 20, 83 (1982).

expected avoided costs under the standard offer."

Edison has suggested that affiliate QFs are less risky than nonaffiliate QFs due to superior financial reliability, but price concessions in response to that financial reliability are not reasonable because there is no evidence that Edison has assessed the impacts of financial reliability on operating risks.

Edison argued that the KRCC decision made no finding of favoritism. The Findings of Fact in D.90-09-088 refer repeatedly to "acts of imprudency," "management decisions... which did not adequately take into account the interests of its ratepayers," and "actions taken by Edison which were at odds with specific Commission directions."[96] Finding of Fact 188 states that Edison "may have considered the interests of its QF affiliates before its ratepayers and other QFs." Taken collectively, the findings in D.90-09-088 demonstrate that Edison has unfairly favored KRCC over nonaffiliate QFs.

The Commission has thoroughly reviewed the KRCC contract, but DRA's evidence in this GRC is insufficient to find favoritism in the Sycamore and Arco-Watson contracts. We do not find that favoritism is absent, but a complete ECAC reasonableness review is necessary to find favoritism. DRA has presented evidence of favorable terms and provisions which might support findings of favoritism after complete reviews of the two contracts, but in this GRC the necessary review is incomplete. We cannot rely on partial evidence regarding the Sycamore and Arco-Watson contracts to support the findings in the KRCC decision and then find that a pattern of favoritism has existed.

However, we will not close the record on the proposed ROE penalty. If in A.89-05-064, A.90-06-001, and A.91-05-050 we should

96 37 Cal. PUC 2d 488 (1990); Findings of Fact 129, 132, and 138.

make findings regarding the Sycamore and Arco-Watson agreements that parallel our findings on the KRCC contract, then we will not hesitate to find in this proceeding that a pattern of favoritism has existed. Appropriate penalties would follow. We leave the record in Phase 1 open, in anticipation of this possibility.

We will not order Edison to produce a semiannual report on affiliate QF negotiations, which it volunteered to file with the Commission if directed to do so. Such a report would not adequately inform all QFs of available nonstandard terms and provisions. However, this does not relieve Edison of its obligations to bargain with QFs in good faith. Edison must protect ratepayers from excessive costs while promoting QF development. In general, these factors should drive QF agreements toward standard offer prices. The Commission can approve nonstandard provisions when both ratepayers and QFs can benefit from them, in instances where QFs and ratepayers value certain provisions differently. Because of Edison's favoritism toward KRCC and alleged favoritism toward Sycamore and Arco-Watson, we conclude that Edison's good faith obligations include the obligation to inform all QFs of significant terms and conditions that Edison has made available to other QFs, affiliated or nonaffiliated. We recognize the public policy choice between open information, which would encourage development of the QF industry, and restricted information, which would encourage lower rates. In this instance, Edison's favoritism toward affilate QFs tips the balance toward open information. We leave to Edison the best way to inform QFs of those provisions, but a report to the Commission twice a year is not enough.

<u>13. Comments to Proposed Decision</u>

In compliance with PU Code $ 311, ALJ Weil prepared a Phase 1 proposed decision, which was mailed to all parties on November 18, 1991. Timely comments to the proposed decision were filed on December 6, 1991 by: CEC, NRDC, SoCalGas, TURN, DRA, Edison, California Department of General Services, and Coalition.

Late comments were filed by: CMA, PG&E, and SDG&E. Timely reply comments were filed on December 13, 1991 by: TURN, DRA, TU, and Edison. Edison's initital comments exceeded the page limitation required in Rule 77.3 by: (1) inclusion of a three page summary incorrectly labeled as a subject index, (2) inclusion of five pages of tables and text incorrectly described as proposed findings of fact and conclusions of law, (3) insertion of additional comments along with proposed findings and conclusions, and (4) transmittal by letter to the assigned ALJ of 12 pages of work papers. All of this material except the summary is new factual information, untested by cross examination. DRA also included two pages of new DSM shared savings tables in its initial comments. We did not rely on any of the excessive or new information in approving this decision.

We have reviewed and carefully considered the comments of the parties in adopting this Fourth Interim Opinion. We have made substantive changes to the ALJ's proposed decision in the following areas: (1) attrition year productivity, (2) prior year expenditures for electric transportation projects, and (3) DSM (measurement and evaluation expenses, TRC calculations, shared savings workshop, and energy cooperative payments). Other minor revisions have been incorporated as necessary throughout the text of the decision.

Findings of Fact

1. On December 7, 1990 Edison filed A.90-12-018, its test year 1992 GRC, requesting: (1) an increase in ALBRR of $173.141 million for the test year, (2) an increase of about $174 million for attrition year 1993, and (3) an increase of about $212 million for attrition year 1994.

2. On December 18, 1989 the Commission issued I.89-12-025, concerning lengthy outages at Palo Verde 1 and Palo Verde 3. In compliance with PU Code § 455.5(c), the investigation was consolidated with A.90-12-018 by ALJ ruling dated February 1, 1991.

3. On February 21, 1991 the Commission issued and consolidated with the GRC I.91-02-079, to investigate revenue requirement, rates, practices, and other aspects of Edison's operations.

4. On March 7, 1991 Edison amended A.90-12-018 to submit Phase 2 testimony.

5. The consolidated GRC is divided into four separate phases: Phase 1 on revenue requirement, marginal costs, and DSM; Phase 2 on revenue allocation and rate design; Phase 3 on the Palo Verde outages; and an anticipated Phase 4 on affiliate transactions.

6. Public participation hearings were held during March 1991 at six locations in Edison's service territory.

7. Fifty days of evidentiary hearings were held on Phase 1 issues.

8. At the time Phase 1 briefs were filed, Edison's requested increase in ALBRR was $191.364 million. DRA recommended $274.099 million less than this amount, for a net reduction of $82.735 million.

9. The parties have agreed that Phase 1 revenue requirement changes should be consolidated with changes ordered in other proceedings, and that rate revisions reflecting the consolidated revenue requirement changes should be ordered in A.91-05-050, Edison's current ECAC application.

10. The ALJ's Phase 1 proposed decision was mailed to all parties on November 18, 1991.

11. It is necessary to adopt a sales forecast in Phase 1 to determine jurisdictional allocation factors, the user tax element of working cash, and postage expenses.

12. Except for agricultural sales, DRA's test year sales forecasts were based on more recent data than Edison's sales forecasts and should be adopted.

13. The adopted test year agricultural sales forecast should be based on average weather conditions.

14. The sales forecasts set forth in Appendix B to this decision are reasonable and should be adopted for Phase 1 purposes.

15. DRA's wage and salary study is incomplete because it does not compare all elements of employee compensation, and it does not report Edison's compensation levels relative to the distribution of compensation levels among comparable firms.

16. With the exception of executive bonuses, Edison's test year forecasts of wages and salaries are reasonable.

17. In Edison's next GRC, Edison and DRA should continue their joint studies on compensation, with more emphasis on total compensation, total benefits as a percentage of cash compensation, and the distribution of total compensation among firms.

18. Edison and DRA agreed that the labor and nonlabor escalation factors set forth in Appendix C to this decision, exclusive of a Cost Containment factor, are reasonable and should be adopted.

19. For accounting and forecasting purposes, uncontrollable expenses are: (1) fuel-related costs, (2) DSM costs, (3) RD&D costs, (4) franchise fees, (5) uncollectibles, (6) postage expenses, and (7) employee health care costs.

20. In order to adopt forecasts of controllable expenses, it is reasonable and necessary to apply Cost Containment adjustments to all operating expenses except the uncontrollable expenses listed above.

21. Edison has included historical total factor productivity improvements in its test year estimates.

22. Edison has not included Cost Containment goals in its test year estimates.

23. Edison's testimony on total factor productivity indicated a range of 1.3% to 1.9% for annual productivity gains from 1976 to 1992.

24. It is reasonable to apply annual adjustments of 50% of the 1.5% to controllable expenses to reflect Edison's Cost Containment program's benefit to ratepayers. Retaining 50% of the 1.5% gains for shareholders will reinforce long term incentives to utility management to control costs, which is in the long term ratepayer benefit.

25. Authorization of controllable O&M costs without adjusting for Edison's Cost Containment program by alloting 50% of the gains to ratepayers would be unjustified and unreasonable.

26. Edison's Cost Containment program began in late 1987. A primary goal of the program is to limit annual growth of all O&M expenses to inflation less 1.5%.

27. The Cost Containment program is on track toward meeting its goal.

28. It is reasonable to apply annual adjustments of 0.75% to controllable expenses to reflect the benefit of 50% of Edison's Cost Containment program for ratepayers, and to include 0.75% of these gains as part of the revenue requirement as a continued incentive to shareholders to aggressively pursue long term cost control, which ultimately benefits ratepayers.

29. For ratemaking purposes it is reasonable to assign Cost Containment gains to controllable expenses broadly, in the same way that Cost Containment goals are established.

30. Power plants deteriorate as they age, but that deterioration is gradual.

31. Increased expense needs for maintenance of aging power plants would appear in trends of recorded data.

32. Production expense Accounts 511, 512, and 513 show no statistically significant expense trends from 1983 through 1988.

33. It is not necessary to increase test year production expenses by $1.353 million for Edison's engineering assessment program.

34. It is not necessary to increase test year production expenses by $138,000 for Edison's protective painting program.

35. It is reasonable to allocate timber and land management expenses at Edison's Shaver Lake facility based on supervisory time spent on utility and nonutility property.

36. PG&E's incentive to maximize capacity factor at Diablo Canyon has resulted in direct benefits to shareholders.

37. A similar incentive would work for Edison.

38. Edison does not adequately consider the balancing of refueling O&M costs at SONGS against replacement power costs when it plans refueling outages.

39. Edison's budgeting process restrains the funds available to do refueling outage work.

40. Edison has made a comparative study of nuclear O&M expenses and endorsed zones of reasonableness equal to plus or minus one standard deviation around the average of expenses, on a basis of annual expenses per plant unit or annual expenses per installed MWe.

41. It is reasonable to compare adopted nuclear O&M expenses with Edison's recommended zones, but the zones are too wide to adopt any level of nuclear O&M expenses within the zones.

42. Edison should perform another zone of reasonableness study in its next GRC.

43. It is reasonable to continue a flexible outage schedule for purposes of adopting test year and attrition year nuclear O&M expenses.

44. It is reasonable to calculate nuclear O&M expenses by separation into base and refueling portions.

45. It is reasonable to base test year O&M expenses at SONGS on recorded 1987, 1988, and 1989 expenses, escalated to reflect labor and nonlabor inflation, and escalated for 2% real growth.

46. DRA's proposed "dollars-per-day" method for estimation of refueling expenses is not reasonable and should be rejected.

47. Edison's Cost Containment goals apply to nuclear O&M expenses.

48. It is reasonable to adopt expenses for NRC fees at SONGS and Palo Verde based on the 1991 NRC budget.

49. The adopted O&M expenses for SONGS are within Edison's proposed zones of reasonableness.

50. Zero-based budgeting of Palo Verde O&M expenses is impractical, because O&M expenses are unstable and data are limited.

51. It is reasonable to adopt test year Palo Verde O&M expenses equal to adopted SONGS O&M expenses times a scaling factor, plus adjustments for NRC fees and the Palo Verde water treatment facility.

52. Edison's proposed relationship between equipment counts and nuclear O&M expenses is untested as a predictor of expenses.

53. DRA's proposed scaling factor of 1.131, used to predict Palo Verde expenses from SONGS expenses, is reasonable for this GRC and should be adopted.

54. The adopted O&M expenses for Palo Verde are within Edison's proposed zones of reasonableness.

55. It is reasonable to base SDG&E's share of SONGS O&M expenses on the expenses adopted for Edison in this decision.

56. It is uncertain that O&M expenses for SONGS 1 will be necessary following completion of fuel cycle 11, which is scheduled to end during the test year or shortly thereafter.

57. In A.90-08-014 Edison has requested authority to sell Yuma Axis to IID.

58. If Edison completes the sale of Yuma Axis before its next GRC rate revision, it has agreed to remove from rate recovery the associated O&M expenses, effective on the date the sale is completed.

59. It is reasonable to leave Yuma Axis O&M expenses in rates until the sale is completed.

60. It is reasonable to base increased Sylmar converter station expenses on monthly billings before and after the station expansion was completed.

61. It is not reasonable to increase Sylmar converter station transmission expenses based on the increase in station capacity.

62. For each FERC transmission and distribution account, it is not reasonable to include in rates expenses which exceed Edison's requested amounts.

63. DRA's detailed reviews of transmission and distribution expenses were more thorough than Edison's reviews.

64. Review of functional subaccounts within FERC accounts can increase data dispersion.

65. It is reasonable to adopt one half of DRA's recommended transmission and distribution expense reductions, to reflect a balance of those two factors.

66. Inspection of underground facilities is an ongoing maintenance activity.

67. DRA's recommended distribution expense adjustment to remove underground inspection expenses is not reasonable and should not be adopted.

68. Edison used more recent data than DRA used to estimate Account 598 uncollectible damage claims and storm damage expenses.

69. DRA used recorded damage expense data rather than accrued damage estimates.

70. It is reasonable to adopt one half of DRA's recommended damage expense reduction, to reflect a balance of those two factors.

71. It is reasonable to adopt Account 598 expenses based on seven years of recorded data from 1984 through 1990.

72. Except for postage expense within Account 903, Edison's expense estimates for customer accounts expenses in Accounts 901, 902, 903, and 905 are reasonable and should be adopted.

73. Test year postage expenses in Account 903 should be calculated based on the adopted number of customers, 14.85 mailings per customer, and Edison's proposed postage rates.

74. Edison and DRA agreed that an uncollectibles factor of 0.208% is reasonable and should be adopted.

75. In D.87-12-066 the Commission authorized A&G expenses based on customer growth because Edison had not adequately justified its requested increase.

76. For the years 1982 through 1988, customer growth explains 57.9% of the variation in Edison's recorded A&G expenses.

77. For the same years, the year of record explains 71.0% of the variation in recorded A&G expenses.

78. The record evidence does not support dependence of Edison's A&G expenses on customer growth.

79. Edison based its estimate of test year Account 920 expenses on recorded 1988 A&G salary expenses. No party objected to use of that base year.

80. In 1988 Edison booked into Account 920 executive bonuses earned in 1987 but awarded in 1988, and bonuses accrued in 1988.

81. It is reasonable to remove from 1988 Account 920 expenses $2.2 million for executive bonuses accrued in 1988.

82. It is reasonable to remove from Account 920 expenses $72,000 for costs of executive chauffeurs for the past Chairman of the Board and the past Executive Vice President.

83. A reasonable threshold for unexplained A&G expense increases is double the average growth rate of controllable expenses.

84. It is reasonable to remove from 1988 Account 920 expenses $275,000 for unexplained increases in corporate communications expenses.

85. Properly formulated executive bonus programs can work to encourage management effectiveness, and costs of such programs should be recovered from ratepayers.

86. Edison's executives are obliged to pursue the interests of both shareholders and ratepayers.

87. The measures upon which Edison awards executive bonuses are overwhelmingly weighted in favor of shareholder interests.

88. Edison's executive bonus measures do not provide adequate incentives for safe, reliable service at reasonable, nondiscriminatory rates.

89. Reliance on Board of Directors' judgment and absence of specific standards diminish the fairness and effectiveness of Edison's executive bonuses.

90. The need for and effectiveness of Edison's bonus plan are obscured by lack of rigorous program assessment and failure to provide DRA with measurements of individual performance.

91. It is necessary to use judgment in authorizing rate recovery of executive bonuses.

92. Two thirds of the recorded executive bonuses, or $1.210 million, should be removed from 1988 expenses in Account 920 before escalation forward to the test year.

93. Executive bonuses for pursuit of shareholder goals and objectives should be paid by shareholders.

94. Edison and DRA have agreed to remove $40,000 for employee memberships from recorded 1988 expenses in Account 921, office supplies and expenses.

95. It is reasonable for Edison to recover test year expenses for its WMBE program on a forecast basis.

96. Edison has had no opportunity to seek rate recovery of test year WMBE expenses in the generic proceeding anticipated in D.89-08-026.

97. Further expense debits into Edison's WMBE clearinghouse memorandum account are unnecessary and should be terminated.

98. It is reasonable to adopt a construction overhead transfer rate of 19.78%, based on recorded data for the years 1984 through 1988.

99. It is reasonable to adopt test year expenses for Account 923, outside services, based on the average of recorded costs for the years 1986 through 1988.

100. The two reductions to Accounts 924 and 925, insurance and damage expenses, recommended by DRA for insurance reserves are reasonable and should be adopted.

101. Edison and DRA have agreed on test year expenses for Account 926.1, pensions and benefits, for employee health care benefits. They do not agree on the exact split of expenses into cost categories.

102. It is reasonable to remove escalation for customer growth from the agreed upon expenses for employee health care benefits. With that adjustment, the agreed upon expenses are reasonable and should be adopted.

103. PBOPs are utility liabilities--principally medical benefits for employees, retirees, and their families--which have in past years been paid on a cash basis, without setting aside funds to cover future costs and without recognition of the liability on financial statements.

104. Effective January 1, 1993, Edison must accrue PBOP liabilities while employees earn the benefits, not when the benefits are actually paid.

105. The Commission is investigating PBOPs in I.90-07-037 and related matters.

106. In this GRC Edison requested $12.6 million in test year expenses to pre-fund PBOP liabilities in an IRC § 401(h) plan. DRA and FEA opposed rate recovery of PBOP costs until further order in I.90-07-037.

107. In D.90-07-006 the Commission authorized Edison to record PBOP costs in a memorandum account.

108. Edison's § 401(h) plan does not cover union employees. Edison intends that union employees will be covered under a VEBA plan.

109. The Commission has not yet authorized full funding of PBOPs in I.90-07-037.

110. The record evidence does not demonstrate that including PBOP expenses in test year rates will not overfund the § 401(h) plan.

111. It is not reasonable to include test year PBOP costs in rates. Edison should continue to record 1992 PBOP costs in the memorandum account authorized in D.91-07-006.

112. Edison should take advantage of tax-exempt PBOP plans, consistent with Ordering Paragraphs 4 and 5 of D.91-07-006.

113. DRA's testimony on administrative costs within Account 926.2, pensions and benefits other than health care, is conclusory and poorly supported by the record evidence.

114. It is reasonable to remove escalation for customer growth from administrative costs within Account 926.2. With that adjustment, Edison's requested funding for administrative costs is reasonable and should be adopted.

115. Test year retirement benefits within Account 926.2 should be based on a 6.14% normal cost rate, Edison's estimate of employee numbers, and Edison's inflation adjustments.

116. It is reasonable to remove unfunded executive retirement plans from retirement benefits, as recommended by FEA. With that adjustment, Edison's requested funding for retirement benefits within Account 926.2 is reasonable and should be adopted.

117. It is reasonable to remove escalation for customer growth from SSP costs within Account 926.2. With that adjustment, Edison's requested funding for SSP costs is reasonable and should be adopted.

118. SSP costs should be recorded in the "other" accounting category, as requested by Edison.

119. Edison and DRA have agreed on test year expenses for disability, rehabilitation, and wage continuation benefits within

Account 926.2. The expenses are not escalated for customer growth. The agreed upon funding is reasonable and should be adopted.

120. Life insurance costs for executive pleasure travel and executive estate and tax planning are unnecessary and should not be recovered from ratepayers. With those two adjustments, Edison's requested funding for life insurance expenses within Account 926.2 is reasonable and should be adopted.

121. Edison and DRA have agreed on a franchise fee rate of 0.7877%. The rate is undisputed, and it should be adopted.

122. Edison agreed to remove $277,000 from recorded 1988 expenses in Account 928, regulatory expenses, because hydroelectric plant relicensing litigation will not recur.

123. It is reasonable to remove $15,000 in unexplained legal costs from Account 928. With that adjustment, Edison's requested funding for Account 928 is reasonable and should be adopted.

124. It is reasonable to remove from Account 930.1, general advertising: (1) escalation for customer growth, (2) $248,000 for in-house advertising that is not safety-related or essential customer information, and (3) $71,000 for exhibits and displays.

125. It is reasonable to reduce expenses in Account 930.2, miscellaneous expenses, by $13.100 million, as shown on Table 4 in this decision.

126. It is reasonable to remove from Account 930.2 escalation for customer growth.

127. Within Account 930.2, Edison requested recovery of $1.730 million in engineering and environmental costs for its BiCEP project. The costs were incurred between 1985 and 1988, and they exclude AFUDC and carrying charges.

128. Edison cancelled the BiCEP project in October 1988, before seeking a CPCN, due to: (1) a changes in assumptions by the CEC, (2) increased capacity from QFs, and (3) increased capacity acquisitions by resale customers.

129. In general, utilities cannot recover the costs of plant that is not used and useful.

130. Recovery of abandoned plant costs can be justified in exceptional circumstances, as described in D.83-12-068, D.84-05-100, and D.89-12-057.

131. The evidence does not show that the BiCEP project ran its course during a period of unusual and protracted uncertainty.

132. Edison did not cancel the BiCEP project promptly.

133. The magnitude of BiCEP project costs does not support granting an exception to the used and useful rule.

134. Within Account 930.2, Edison requested recovery of $3.231 million for minor abandoned projects. Edison has not identified specific projects in that request.

135. Within Account 930.2, Edison requested recovery of $193,000 in expenses for its Citation aircraft.

136. Edison's use of the Citation aircraft is reasonable. The requested funding is reasonable and should be adopted.

137. Within Account 930.2, Edison requested recovery of $337,000 in expenses for dues, fees, and contributions.

138. It is reasonable to remove from test year dues, fees, and contributions $35,000 in EEI dues used for legislative policy research and $62,000 for membership in the NMRC.

139. Pensions for members of Edison's Board of Directors are not necessary and should not be recovered in rates.

140. Edison is in the process of moving its aircraft operations from Chino Airport to Ontario Airport. As part of that move, Edison plans to complete the purchase of a hangar that it now leases at Ontario. Edison plans to complete the purchase in 1992.

141. When the hangar sale is completed, Edison's lease costs at Ontario will be reduced from $200,000 to $21,000 annually.

142. DRA opposed inclusion of the Ontario hangar in rate base, consistent with its recommendation on operating expenses for the Citation aircraft.

143. Edison will use the Ontario hangar for the Citation aircraft and for eight helicopters.

144. It is reasonable to include the Ontario hangar in rate base, assuming that the purchase will be completed midway through the test year.

145. Edison's lease at the Chino Airport expires at the end of 1993.

146. Chino Airport annual lease costs are $35,600, duplicating test year lease costs at the Ontario Airport.

147. It is reasonable to remove from Account 931, rents, one half of the costs of the Chino lease and one half of the lease cost reduction at Ontario, to reflect completion of the hangar purchase.

148. It is reasonable to exclude escalation for customer growth from Account 935, maintenance of general plant.

149. There are no methodological disputes among the parties regarding calculation of income taxes.

150. Edison is co-plaintiff in Arizona Public Service Company vs. Maricopa County, in which the owners of Palo Verde seek judgment against the county for levying an additional property tax too narrowly, specifically against mines and utilities.

151. If the lawsuit is successful, Edison's projected Arizona property taxes for the test year would be reduced by $9.488 million.

152. The outcome of the lawsuit is uncertain, and Edison's Arizona property tax obligations are too uncertain to adopt a reasonable forecast.

153. DRA's proposal for memorandum account treatment of the disputed Arizona property taxes is reasonable and should be adopted.

154. Until the lawsuit is resolved, Edison's disputed Arizona property taxes should be collected in rates subject to refund and booked into the memorandum account.

155. FEA contended that Edison should pursue recovery of Arizona property taxes paid during the lengthy outages at Palo Verde because the outages were caused by instructions from the NRC, and Section 42 allows reduced taxes in that circumstance.

156. The Palo Verde outages lasted longer than six months.

157. Edison's rates for portions of the Palo Verde outages are now subject to refund.

158. Further consideration of property tax reductions under Section 42 should be deferred to Phase 3 of this GRC.

159. Edison requested capitalization of $10.1 million in test year software costs and test year capitalization of 1990 and 1991 software costs that exceeded authorized expense levels.

160. Test year capitalization of 1990 and 1991 software costs would be unfair to ratepayers.

161. Edison has recovered reasonable 1990 and 1991 software costs on a forecast basis, whether the actual expenses exceeded authorized expenses or not.

162. Edison has not shown that capitalization of software costs will benefit ratepayers.

163. Edison's requests for capitalization of software costs are unreasonable and should be denied at this time.

165a. Edison may elect to file additional information on the merits of capitalized software within 120 days of the effective date of this order served on all parties to this case. Parties may respond to Edison's filing within 120 days of receipt of Edison's filing at the Commission.

164. Information services increase productivity in other utility departments.

165. DRA's proposed $10 million cost offset for information services would unfairly double count productivity gains.

166. Edison's information services budgeting process hindered timely review of test year expenditures by DRA.

167. It is reasonable to adopt test year expenses for information services based on recorded 1990 expenses. This results in a $4.607 million reduction from Edison's requested funding, in 1988 dollars. The reduction should be expressed as the net of a $10.1 million reduction in capital costs and a $5.493 million increase in expenses, prorated over the nonlabor portions of relevant A&G accounts.

168. The test year O&M expenses set forth in Appendix D to this decision are reasonable and should be adopted.

169. It is likely that deferral of plant additions at the beginning of a forecast period will be offset by deferrals at the end of the forecast period.

170. Recorded data should be used to forecast test year plant in service whenever the data are available.

171. DRA's use of recorded plant in service data through the end of 1990 is reasonable, and the associated reduction of $162.649 million in test year plant in service should be adopted.

172. Consistent with the removal of Yuma Axis O&M expenses upon sale of the property, Edison should remove Yuma Axis plant from rate base and remove capital-related revenue requirement from the ALBRR upon sale of the property.

173. RD&D capitalization guidelines are set forth in D.82-12-005 and D.83-12-068.

174. The guidelines should be clarified as follows: (1) tangible plant in utility operations means plant that is owned, operated, and maintained by the utility, and (2) demonstration of technologies to encourage customer acceptance and eventual market penetration, or showcasing, is not an RD&D function.

175. Showcasing activities may be justified for other reasons.

176. Edison requested capitalization of 19 RD&D projects, including $7.379 million for electric transportation projects undertaken from 1988 through 1991.

177. For all 19 projects, Edison has not met the standards for case-by-case exceptions to the Commission's general principles for capitalization of RD&D costs.

178. It is reasonable to remove from plant additions $5.119 million of property that Edison has reclassified from plant in service to other accounts, principally non-utility property.

179. APS notified Edison that completion work at Palo Verde scheduled for 1990 would not be completed, necessitating some 1991 charges.

180. Edison estimated the 1991 charges to be $1.8 million, which with overheads would result in $2.211 million of plant additions.

181. The same $1.8 million of work is included in both the 1990 Palo Verde budget and the 1991 estimate of APS charges.

182. The disputed $2.211 million in plant additions should be removed from 1990 plant additions.

183. A second Palo Verde simulator will not go into service until the end of the test year.

184. Edison believes that APS will spend funds budgeted for the second simulator on other projects. If that were true, there is no evidence on the record that the replacement projects are necessary.

185. The costs of the second simulator should be removed from test year plant in service.

186. Capital costs of major projects can be included in attrition year plant additions, beyond formula increases for smaller plant additions.

187. In D.85-12-024 the Commission capped capital additions for fuel cycles 9, 10, and 11 at SONGS 1. The spending cap is $201 million, in 1986 dollars.

188. Edison requested $32.960 million in attrition year 1993 plant additions for work which was previously scheduled to be

completed during fuel cycles 9, 10, and 11, but which is now scheduled to be completed during fuel cycle 12 at SONGS 1.

189. The requested $32.960 million is for projects that were listed in calculation of the $201 million spending cap.

190. As of December 1990, 10 of the 35 plant modifications listed in calculation of the spending cap were deferred to fuel cycle 12 or beyond.

191. Edison anticipates that overall capital costs for fuel cycles 9, 10, and 11 will exceed $201 million, but Edison does not seek to recover in rates any costs exceeding the spending cap.

192. During fuel cycles 9, 10, and 11 the scope of plant additions was modified and expanded by the NRC.

193. During fuel cycles 9, 10, and 11 Edison did not complete the work authorized under the spending cap, but it did complete other work.

194. There is no evidence on the record that the other work is cost effective, nor is there evidence on which recorded costs during fuel cycles 9, 10, and 11 were dedicated to the other work.

195. D.85-12-024 authorized Edison to complete the identified SONGS 1 modifications, subject to the spending cap, but at least an additional $32.960 million is needed to complete the work.

196. Edison has not justified the costs for any replacement work done during fuel cycles 9, 10, and 11.

197. In D.90-09-059 the Commission specified the allocation of capital costs for a transmission line between Edison's Kramer and Victor substations among Edison, Luz International, and Cal Energy.

198. Cal Energy has disputed its cost allocation.

199. Edison requested that Cal Energy's allocated costs be included in plant in service until the dispute is resolved.

200. It is not reasonable to include Cal Energy's costs in test year plant in service, but Edison should be authorized to record the revenue requirement associated with Cal Energy's

allocated capital costs in a memorandum account, pending the outcome of Cal Energy's cost allocation dispute.

201. Edison requested inclusion of $8.323 million of property in PHFU under the guideline exceptions established in D.87-12-066.

202. The need to present alternative power plant sites to the CEC does not justify keeping four properties in PHFU.

203. Edison's economic analysis of its power plant sites is incomplete.

204. There is no evidence on the record that Edison can outperform the real estate market in general.

205. The market for the land Edison is holding for power plant sites is speculative.

206. Edison has not justified granting exceptions to the PHFU guidelines, and the disputed $8.323 million should be removed from PHFU.

207. Edison books the costs of nuclear design documentation in Account 182.2 as a deferred debit, with amortization to Account 407.

208. DRA opposed the inclusion of nuclear design documentation costs in rate base, in part because capitalization has been denied by FERC in similar circumstances.

209. Other deferred debits which are not capitalized are included in rate base.

210. Edison should be allowed to earn a return on nuclear design documentation costs until they are amortized in rates. Inclusion of the deferred debits in rate base will accomplish this.

211. Distribution line additions are a better predictor of customer advances than the year of record.

212. DRA's recommendation to remove $2.601 million in customer advances from rate base is reasonable and should be adopted.

213. It is reasonable to adjust Edison's requested working cash: (1) to remove nonrecurring charges to "other accounts receivable" for earthquake damage claims and fire damage claims,

and (2) to exclude early payments to utility affiliates for purchased power.

214. Edison's estimates of revenue lag reduction due to imposition of a late payment charge are reasonable and should be adopted.

215. It is reasonable to include in rate base the capital costs of a limited number of energy-efficient, amorphous core transformers.

216. DRA's recommendation to use later data for depreciation reserve is reasonable and should be adopted.

217. It is reasonable to reduce depreciation revenue requirement by $779,000 to reflect updated cost studies for decommissioning of Edison's nuclear plants.

218. Edison should present testimony in its next GRC on nuclear decommissioning trust fund earnings rate and contingency factor.

219. Edison's RD&D showing suffered from problems of late program revisions, unexplained capital costs, inconsistency between testimony and briefs, and attempts at wholesale capitalization of prior year expenses and undepreciated capital costs.

220. Edison's RD&D showing justifies ordering a financial audit of RD&D expenses from 1988 through 1992. The audit should be coordinated by CACD, at Edison's expense.

221. Edison's RD&D efforts should strive for a balanced portfolio of supply, transmission and distribution, and end use projects.

222. Existing guidelines for shifting of RD&D funds should be continued, as discussed in Chapter 8, Section 8.1.

223. Edison's request that the Commission set an RD&D funding range arrived too late for consideration in this GRC.

224. Edison's "Customer Air Quality Improvement Program" is intended to help customers meet their air quality requirements, stay competitive, and remain in Southern California.

225. With respect to its "Customer Air Quality Improvement Program," Edison should refrain from activities and project implementation which would frustrate the Commission's goal of encouraging energy efficiency and energy conservation.

226. Policy implications of ratepayer funding of air quality improvements which may not be directly linked to delivery of energy should be reviewed in R.91-08-003/I.91-08-002.

226a. Commission implementation of Public Utilities Code § 740.4 should be reviewed in R.91-08-003/I.91-08-002.

227. Edison's one-way balancing account for unspent RD&D funds is reasonable and should be continued.

228. It is reasonable to credit all royalties, licensing fees, and other revenues attributable to Edison's RD&D programs to a memorandum account.

229. The RD&D program expenses listed in column (6) of Table 5 and discussed in Chapter 8 of this decision are reasonable and should be adopted.

230. RD&D funding of $48.714 million, in 1988 dollars, is reasonable and should be adopted.

231. Edison and DRA agreed that Edison should be allowed to recover $2.108 million in test year expenses for electric transportation projects, and that Edison should be allowed to retain or recover $20.828 million in prior year expenditures which exceeded amounts authorized in Edison's last GRC.

232. From 1988 through 1991 Edison spent more on electric transportation projects than the Commission had authorized in rates.

233. The agreed upon funding level of $2.108 million for electric transportation projects is reasonable and should be adopted.

234. The conditions on electric transportation program scope, reporting, and fund shifting set forth in Exhibit 112 are reasonable and should be adopted.

235. Edison's request to retain in rates $13.449 million in 1988 through 1991 expenditures which exceeded amounts authorized for electric transportation projects is reasonable.

237a. Edison's request to recover in rates $7.379 million in 1988 through 1991 expenditures which exceeded amounts authorized for electric transporation projects is unreasonable and should be denied.

236. Policy considerations for electric vehicles and electric transportation should be deferred to I.91-10-029 or other appropriate proceedings.

237. Edison's intention to rejoin EPRI is contingent on the Commission's approval of RD&D funding near the $55 million level.

238. The net cost to Edison to rejoin EPRI would be about $10 million.

239. It is not reasonable to authorize expenses for EPRI dues in these circumstances.

240. It is reasonable to continue ERAM treatment of nonfuel revenues from off-system sales, without adjustment to remove incremental O&M costs.

241. Edison should continue to forecast off-system sales revenues in ECAC and GRC proceedings.

242. DRA has not justified its recommended increase of $8 million in miscellaneous revenues, attributed to sales of obsolete materials and supplies.

243. It is reasonable to calculate miscellaneous revenues in Account 456 based on 1989 and 1990 recorded revenues.

244. Edison and DRA agreed on CPUC jurisdictional factors used to allocate costs between CPUC and FERC jurisdictional customers. The jurisdictional factors are reasonable and should be adopted.

245. Edison's proposed MAAC treatment for installation of SCR technology at Alamitos 6 is reasonable and should be adopted, except that: (1) incremental noninvestment-related costs should not be authorized, as DRA recommended, (2) interim rates should be

$0.00011 per kWh, and (3) interim rates should be reduced by 5% annually to reflect the reduction of revenue requirement as the asset is depreciated.

246. DRA's calculation method for attrition year plant additions was adopted in the 1991 attrition settlement and will smooth out data fluctuations. It is reasonable and should be adopted.

247. Edison's request for attrition year plant additions for small NOx reduction projects and for nuclear design documentation costs would expand the scope of GRCs by allowing individual plant additions into attrition year rate base.

248. In D.82-12-055 the Commission rejected a similar request by Edison.

249. Inclusion of small NOx reduction projects and nuclear design documentation costs in attrition year plant additions is unreasonable and should be denied.

250. Edison and DRA agreed to use separate attrition year escalation factors for health care expenses, but they disagreed on the values of the escalation factors.

251. Neither Edison nor DRA has made the escalation factor adjustments necessary to avoid double counting of health care escalation.

252. The agreed upon escalation of health care expenses is unreasonable and should be denied.

253. The summary of earnings calculations set forth in Appendix D to this decision are reasonable and should be adopted.

254. The attrition calculations set forth in Appendix E to this decision are reasonable and should be adopted. Various example inputs to those calculations should be updated when Edison formally requests revenue requirement revisions for the 1993 and 1994 attrition years.

255. The ALBRR of $4,011.952 million developed in Appendix D to this decision covers Phase 1 revenue requirement, is reasonable, and should be adopted, effective January 1, 1992.

256. The revision to Edison's ALBRR authorized in this decision is justified.

257. Edison's management authorizes capital budgets in advance of individual project justification for refueling O&M costs at SONGS, for plant additions by APS at Palo Verde, and for information services.

258. In its next GRC Edison should present testimony on its management policies and practices for planning and approval of capital projects, as discussed in Chapter 9 of this decision.

259. A.85-12-012 is the appropriate proceeding to consider disallowance of DPV2 costs.

260. In its next GRC Edison should report total capital costs for its HVDC expansion project.

261. It is reasonable to continue memorandum account treatment of hazardous waste management costs, and to extend this ratemaking treatment to costs to comply with storm water discharge regulations.

262. Most Phase 1 marginal cost issues have been resolved in uncontested joint testimony received into evidence as Exhibit 113 and Exhibit 117.

263. The joint testimony determined calculation methods and many inputs to the calculations. Other inputs are determined by expenses adopted elsewhere in Phase 1. Marginal energy costs also depend on natural gas prices adopted outside this GRC.

264. Exhibit 113 clearly states that marginal cost methodological issues should be resolved in GRCs, and Phase 1 is the forum for marginal cost issues in this GRC.

265. The method for calculating the gas price should be resolved in Phase 1 of this GRC.

266. Interstate gas supply is the best available proxy for a marginal gas source.

267. The three-part construction of marginal gas costs proposed by IU and used in Edison's last ECAC proceeding is reasonable and should be adopted.

268. Edison should perform a study on minimum marginal transformer costs and system efficiency costs, as requested by TURN. A report should be completed within six months.

269. The marginal costs set forth in Appendix F to this decision are reasonable and should be adopted, subject to revisions for gas prices adopted outside this proceeding.

270. Workshops to determine data sets to be used in construction of marginal cost IERs were not necessary in this GRC.

271. For purposes of this GRC, Edison's ER90 barebones resource plan, adjusted to remove forecasted QFs and self-generation, is reasonable and should be adopted.

272. Edison's six-year average ERI is 0.63, based on the adopted resource plan.

273. DRA's fully built resource plan should also be adopted, but without specified purpose. Use of the plan in future circumstances must be justified by the user.

274. Edison requested DSM funding for: (1) amortization of 1990 and 1991 costs, as authorized in D.90-08-068, (2) shared savings programs, (3) modified expense programs, (4) ordinary expense programs, and (5) capitalization of energy-efficient transformers.

275. DSM policy issues should be considered in the DSM rulemaking.

276. Edison's 10 proposed policy principles are vague and inadequately define limits to utility DSM activities.

277. DRA's proposed FEIP are complicated and too restrictive to account for changing circumstances.

278. DSM bidding should be considered in the DSM rulemaking.

279. The DSM program expenses listed in column (I) of Table 7 and discussed in Chapter 11 of this decision are reasonable and should be adopted.

280. DSM test year expense funding of $140.860 million, in 1992 dollars is reasonable and should be adopted.

281. DSM funding in test year 1992 is more than twice the authorized funding in test year 1988, in constant dollars, and 27% higher than 1990 expenses authorized in D.90-08-068.

282. Within the direct assistance program for residential energy conservation, $600,000 should be redirected from residential infiltration control to basic weatherization.

283. Funds for the Golden Carrot program should not be expended until superefficient refrigerators are shipped into Edison's service territory as a result of the program.

284. Funds for the Golden Carrot program should not be eligible for incentive payments to shareholders.

285. A&G expenses, including advertising, for the compact fluorescent light bulb program should not exceed 30% of program costs.

286. In its March 1993 DSM annual report Edison should report on the cost-effectiveness of test year residential energy audits.

287. Ratepayer funding of a program to promote residential TOU rate schedules is unnecessary and should be denied.

288. Edison's requests for funding to promote residential and nonresidential outdoor security lighting are unreasonable and should be denied.

289. Incentive payment caps might limit utility pursuit of energy savings opportunities.

290. On an interim basis Edison should not limit incentive payments, but the issue should be considered in the DSM rulemaking.

291. Edison's request for $1.000 million in funding for miscellaneous conservation activities is unreasonable and should be denied.

292. Edison should make no incentive payments for thermal energy storage projects with forecast TRC ratios less than 1.0.

293. DRA's recommendation to cap thermal energy storage incentive payments at $50 per kW is unreasonable and should be rejected.

294. Policy issues for utility fuel substitution, load retention, and load building programs should be considered in the DSM rulemaking.

295. Edison's request for funding of a program to retrofit commercial cooking equipment is reasonable and should be adopted, if the program is limited to retrofits of electric equipment.

296. Edison's requests for funding of electric induction melting and infrared curing and drying programs are reasonable and should be approved.

297. Edison's request for funding of a program for dielectric heating in baking, rubber, and pharmaceutical operations is reasonable and should be adopted.

298. In its March 1993 DSM annual report Edison should report on the cost-effectiveness of its dielectric heating program.

299. Edison's requests for funding of three load retention programs are reasonable and should be approved.

300. Edison's proposed load building programs for ventless dry cleaning equipment, ozone water treatment, and coating processes are reasonable and should be approved.

301. Edison's request for funding of the electric chiller program is reasonable and should be adopted.

302. Edison has the burden of proof in its next general rate case to show the cost-effectiveness of all load retention and load building programs where it is requesting ratepayer funding.

303. Edison should cooperate with DRA, CEC, and other utilities to develop consensus techniques to measure and evaluate DSM programs.

304. It is reasonable to adopt Edison's requested funding for measurement and evaluation activities, and to defer program details to the DSM rulemaking.

305. Edison should submit, in its next GRC, detailed assessments of economic, environmental, and any other claimed benefits of fuel substitution, load retention and load building programs should it seek to continue or expand these programs.

306. Edison should include in its next GRC, detailed environmental evaluation of the impact of technologies it chooses to promote, as described in this decision.

307. In its March 1993 annual DSM report, Edison should submit a table indicating the source and amount of funding for CTAC.

308. It is reasonable to reinstate the DSM fund shifting rules ordered in D.87-12-066, except that no funds should be shifted into programs for fuel substitution, load retention, or load building nor may funds be shifted among those programs.

309. A DSM fund shifting limitation of $2.5 million should be applied to each GRC cycle.

310. It is reasonable to authorize DSM funding increases in these circumstances: (1) increases should be allowed only by separate application, (2) increased funding must be justified by increased demand for utility programs, and (3) shareholder incentive targets must be adjusted to reflect the increased funding.

311. Increased demand for utility DSM programs should be measured by comparison of participation rates with forecast participation rates.

312. DSM program savings are generally measured as the product of forecast savings per installed unit times recorded installation numbers.

313. The active parties agreed that shareholder incentive payments should be based on actual, not forecast, installations.

314. On an interim basis until the issue can be considered in the DSM rulemaking, Edison should calculate shareholder incentive payments based on forecast unit savings, not updated to reflect later measurements of savings.

315. Edison should substantiate DSM program savings used to calculate shareholder incentive payments.

316. Incentive programs which benefit shareholders without their making capital investments are reasonable because they help overcome imperfections in the market for energy efficiency, but incentive programs may not be permanent.

317. It is reasonable to depart from the risk-reward standard in order to overcome DSM market imperfections.

318. The net benefits used as a basis for calculation of shareholder incentive payments should be total resource benefits less the average of utility cost and total cost.

319. In its next GRC Edison should present testimony on the long run cost-effectiveness of utility DSM efforts, with specific attention to free riders and to marketplace obstacles and progress toward overcoming them.

320. It is reasonable to adopt a program of shared savings shareholder incentives.

321. Edison's proposed modified expense programs, under which shareholder incentive payments are based on utility expenses, not program savings, are reasonable for non-mandatory Direct Assistance and Energy Management Services.

322. The interim incentive function developed and set forth in Appendix G to this decision is reasonable and should be adopted.

323. The incentive functions proposed by Edison and DRA contain perverse incentives associated with high incremental shareholder payments at trigger or cutoff values of achieved energy savings.

324. The adopted interim incentive function offers: (1) penalties for very low savings, (2) a zero-intercept for

savings, (3) low incremental incentive rates at very low and very high savings, (4) greatly increased incentive rates near forecast savings, and (5) smooth transitions between the different savings regions.

325. We do not endorse pre-specified savings with respect to customized rebates as they are incorporated in the Edison resource benefit data we use herein.

326. A reasonable interim basis for determing shareholder incentive payments is: energy benefits, less the average of utility costs and total costs.

327. A reasonable interim incentive target for shareholder rewards is utility expenses for eligible programs times authorized rate of return.

328. Shareholder DSM incentives should be awarded before payment of income taxes.

329. In response to enactment of PU Code § 701.1, Edison has agreed to withdraw its customer incentive payment cap and to seek to expand its DSM programs where cost-effective opportunities are identified.

330. Prudency reviews of DSM expenditures are now and should continue to be made on a forecast basis.

331. The record evidence does not support NRDC's conclusion that Edison's DSM efforts do not duplicate the efforts of any other entity.

332. Customer responses to energy prices are limited by market imperfections, but those responses demonstrate that entities other than utilities are exploiting cost-effective conservation and improvements in the efficiency of energy use.

333. Although both utilities and other entities are exploiting conservation opportunities, there is no evidence on the record about their pursuit of the same opportunities.

334. It is reasonable for Edison to remove $13.449 million in historical expenses for electric transportation under RD&D.

335. In its next GRC Edison should present a DSM comparison exhibit which sets forth the positions of all active DSM parties.

336. It is not reasonable to require that A&G expenses in all of Edison's DSM programs be limited to 30% of program costs.

337. Until the issue is considered in the DSM rulemaking, TRC calculations should continue to exclude customer incentives as a cost.

338. Edison and its affiliates are authorized to own up to 50% of QF projects which sell power to Edison.

339. Affiliate QF projects provide more that 40% of the QF generation purchased by Edison.

340. DRA recommended that the Commission impose a 40 basis point ROE penalty on Edison for failure to comply with Commission regulations regarding affiliate QFs.

341. The recommended penalty is separated into a 20 basis point penalty for repeated failure to provide information regarding affiliates and a 20 basis point penalty for anticompetitive favoritism of affiliate QFs over nonaffiliates.

342. Taken together the penalties would reduce test year revenue requirement by $35.9 million.

343. In D.82-12-055 the Commission penalized Edison 10 basis points for two years for failure to comply with Commission policies on pricing of QF contracts at full avoided costs.

344. Disallowances are denials of rate recovery for unreasonable costs, whether those costs are ordinary expenses, capital costs, or costs induced by unreasonable forecasts.

345. Penalties are punishments for offenses or actions contrary to statute, order, rule, instruction, or express policy.

346. Adverse consequences to shareholders due to Commission decisions or disallowances are not penalties.

347. The KRCC disallowance ordered in D.90-09-088 was not a penalty.

348. The Commission's denial of Edison's proposed merger with SDG&E in D.91-05-028 was not a penalty.

349. Separate penalties and disallowances are possible in response to the same utility behavior.

350. The Commission should not refuse to order a justified penalty because of the financial community's anxiety about adverse consequences to shareholders.

351. Edison has failed to follow Commission instructions regarding provision of information in the KRCC reasonableness review and the merger proceeding.

352. Edison has failed to meet clear standards of behavior for provision of information.

353. If information disputes similar to those in the KRCC and merger proceedings should be repeated in future ECAC reasonableness reviews, DRA should submit additional testimony on replacement power costs, as if the disputed affiliate QF contracts did not exist.

354. An ROE penalty is an appropriate regulatory response to affiliate QF favoritism.

355. DRA's evidence of favoritism is circumstantial.

356. In this proceeding an ROE penalty for favoritism should be supported by evidence of favoritism in the negotiation, execution, or administration of more than one affiliate QF contract.

357. During the review period considered in A.88-02-016, Edison unfairly favored KRCC over nonaffiliate QFs.

358. The evidence in this GRC is insufficient to find that Edison unfairly favored Sycamore and Arco-Watson over nonaffiliate QFs.

359. The evidence in this GRC is insufficient to find more than one instance of favoritism.

360. It is necessary to leave the record in Phase 1 open because favoritism in the Sycamore and Arco-Watson contracts may be

found in the reasonableness review phase of A.89-05-064, A.90-06-001, and A.91-05-050.

361. Edison should protect ratepayers from excessive costs for QF purchases and should promote QF development.

362. In its current consolidated ECAC reasonableness reviews Edison should submit additional testimony on: (1) incremental base rate O&M costs of shortening refueling outages, and (2) incremental replacement power costs associated with extending refueling outages. DRA should have the opportunity to serve responsive testimony. This additional testimony is necessary for the Commission to review the reasonableness of replacement power costs during refueling outages.

Conclusions of Law

1. Phase 1 of this GRC has been conducted according to the Rate Case Plan.

2. Sales and customer forecasts should be revisited in Phase 2, for revenue allocation and rate design purposes.

3. Edison should continue to pursue aggresive cost containment goals, and it is reasonable to assign 50% of expected 1.5% cost containment productivity savings to ratepayers and 50% to shareholders to strengten long term company incentives to pursue these goals to the long term benefit of ratepayers.

4. Utilities that operate nuclear power plants are required to pay fees which are set by the NRC.

5. Edison should be ordered to perform another zone of reasonableness study for nuclear O&M expenses in its next GRC.

6. Edison's O&M expenses at SONGS 1 should be authorized subject to refund.

7. Edison should be ordered to: (1) remove from its ALBRR the O&M and capital-related expenses for Yuma Axis, and (2) remove

from rate base the plant in service and depreciation reserve for Yuma Axis, effective on the date the proposed sale of Yuma Axis to IID is completed.

8. Edison should not be authorized to recover 1993 and 1994 WMBE expenses which are based on the test year expenses authorized in this decision. Expenses for those years should be recovered by separate application in a generic proceeding.

9. FASB Statement of Financial Accounting Standards No. 106 requires that Edison must accrue PBOP liabilities while employees earn the benefits, effective January 1, 1993.

10. Use of union employee PBOP liabilities to calculate $ 401(h) contributions is not unfair to union workers.

11. The PBOP memorandum account preserves Edison's opportunity to recover reasonable PBOP costs in rates.

12. In D.83-12-068, D.84-05-100, and D.89-12-057 the Commission established standards for exceptions to the rule that utility plant in rate base must be used and useful.

13. Edison should be ordered to establish a memorandum account to track disputed Arizona property tax expenses.

14. Section 42 allows for reduced property taxes at Palo Verde when a governmental order prohibits use of the plant for periods in excess of six months.

15. Confirmatory Action Letters from the NRC are not governmental orders.

16. Capitalization of any 1990 and 1991 software expenditures could be retroactive ratemaking.

17. In D.82-12-005 and D.83-12-068 the Commission established guidelines for capitalization of RD&D expenditures.

18. Capitalization of RD&D expenditures from years prior to 1992 would be retroactive ratemaking, unless those expenditures qualify for capitalization under the established guidelines and the expenditures were clearly not for activities anticipated in RD&D funding previously authorized by the Commission.

19. Edison may file in this proceeding additional information to substantiate its request for capitalization of RD&D projects which have received expense treatment at this time.

20. In D.87-12-066, Conclusion of Law 71, the Commission authorized rate recovery of expenditures for electric transportation RD&D projects to $100,000 per year.

21. Conclusion of Law 71 in D.87-12-066 needs to be considered in context of RD&D fund shifting rules.

22. The recovery in test year rates of 1988 through 1991 electric transportation RD&D expenditures in excess of $100,000 per year is inappropriate. The retention of any such expenditures already recovered in rates is allowed.

23. For purposes of test year forecasts in its next GRC, Edison should remove $13.449 million in historical expenses for electric transportation under RD&D.

24. The SONGS 1 cost cap ordered in D.85-12-024 applies only to the 35 projects identified in the cost-effectiveness calculations that supported the cap.

25. For the purpose of determining compliance with the cost cap, Edison is not authorized to substitute other projects for the 35 identified projects.

26. Costs necessary to complete unfinished work within the 35 identified projects should not be recovered in rates until the work is completed.

27. No costs for projects other than the 35 identified projects can be included in rate base until they are justified.

28. The NRC has the authority to order plant modifications at SONGS 1, but it does not have the authority to order rate recovery of unjustified costs.

29. The disputed $32.960 million should be removed from 1991 plant additions, because the modifications authorized in D.85-12-024 are not completed.

30. Edison should be authorized to return the $32.960 million to plant in service upon a showing that the modifications authorized in D.85-12-024 have been completed.

31. Edisión may, in this proceeding, make a filing to demonstrate the cost effectiveness of previously unjustified SONGS 1 costs for any NRC replacement work done vuring fuel cycles 9, 10, and 11.

32. Edison should be authorized to establish a memorandum account to record the capital-related revenue requirement for the costs of transmission lines and other facilities which were allocated to Cal Energy in D.90-09-059.

33. In D.87-12-066, Appendix B, the Commission established guidelines for PHFU.

34. Nuclear design documentation expenditures should not be capitalized, but they can be treated as deferred debits.

35. Deferred debits can be included in rate base if the expenditures are justified.

36. Edison must enforce late payment charges fairly and uniformly, in accordance with filed tariffs.

37. Edison should be ordered to present testimony in its next GRC on nuclear decommissioning trust fund earnings rate and contingency factor.

38. Edison should be ordered to improve its showings on the ratemaking treatment of RD&D costs.

39. Edison should be ordered to undergo a financial audit of its 1988 through 1992 RD&D activities. The audit should be coordinated by CACD, at Edison's expense. A final report should be completed by June 30, 1993.

40. The RD&D funding ranges ordered in D.90-09-045 do not apply to this GRC.

41. The RD&D fund shifting rules discussed in Chapter 8, Section 8.1 should be authorized.

42. Edison should be ordered to establish an interest bearing memorandum account to record all royalties, licensing fees, and other revenues attributable to Edison's RD&D programs. The account balance should be returned to ratepayers in Edison's next GRC.

43. Edison should be authorized to include in its MAAC tariff SCR technology at Alamitos 6, as discussed in this decision.

44. Edison should be authorized to seek 1993 and 1994 attrition adjustments by advice filings.

45. Edison should be ordered to file forecasts of off-system sales revenues and revenue consolidation tables in future GRCs, ECAC proceedings, and other proceedings in which rates are revised.

46. Edison's next GRC should be filed for a 1995 test year, based on recorded operations through 1992. The GRC should be processed according to the Rate Case Plan.

47. Edison should be ordered to present testimony in its next GRC on its management policies and practices for planning and approval of capital projects.

48. Edison should be ordered to report on total expenditures for the HVDC expansion project in its next GRC.

49. Edison's authority for memorandum account treatment of hazardous waste expenses, ordered in Decisions 87-12-066, 89-01-039, and 89-09-019, should be extended through the end of 1994. Similar memorandum account treatment should be authorized for expenses to comply with pending storm water discharge regulations promulgated by the U.S. Environmental Protection Agency.

50. Edison should be ordered to perform a study on minimum marginal transformer costs and system efficiency costs, as requested by TURN.

51. IER workshops were not necessary in Phase 1.

52. CACD should be authorized to determine the need and scheduling for workshops to determine data sets to be used in construction of marginal cost IERs or QF payment IERs.

53. Edison should be ordered to report on the cost-effectiveness of test year residential energy audits in its March 1993 DSM annual report.

54. Edison should be ordered to report on the cost-effectiveness of its test year fuel substitution programs in its March 1993 DSM annual report.

55. Edison should be ordered to submit in its next GRC detailed assessments of economic, environmental, and any other claimed benefits for fuel substitution, load retention and load building programs should it seek to continue or expand these programs.

56. Edison should be ordered to include in its next GRC, detailed environmental evaluations of the impact of the technologies it chooses to promote as decribed in this decision.

57. In its March 1993 annual DSM report, Edison should be ordered to submit a table indicating the source and amount of funding for CTAC.

58. Edison should be ordered to show the cost-effectiveness of all load retention/load building programs in its next GRC if it requests ratepayer funding.

59. Lobbying expenses should be borne by shareholders, not ratepayers.

60. Edison's DSM fund shifting rules ordered in D.87-12-066 should be reinstated, except that no funds should be shifted into programs for fuel substitution, load retention, or load building.

61. Edison should be ordered to present testimony in its next GRC on the long run cost-effectiveness of utility DSM programs, with specific attention to free riders and to marketplace obstacles and progress toward overcoming them.

62. Edison should be authorized to recover from ratepayers incentive payments to shareholders based on shared savings from eligible DSM programs.

63. Edison should be ordered to specify all underlying assumptions and calculations for its total resource costs on all shared savings programs approved herein, subject to Commission approval.

64. The shared savings incentive payments to shareholders authorized in this decision are justified.

65. The shared savings program authorized in this decision is just and reasonable.

66. The adopted shared savings program is consistent with the requirements of PU Code $ 746.

67. PU Code $ 701.1 must be considered along with PU Code $$ 451, 454, and 728, which require just and reasonable rates, and other ratepayer protection objectives.

68. Absent evidence on which conservation opportunities are exploited by Edison and other entities, Edison's obligations to seek to exploit conservation and efficiency improvements under PU Code $ 701.1 are uncertain.

69. Authorization for rate recovery of reasonable DSM expenses and other DSM actions taken by the Commission in this decision do not in any way hinder Edison from compliance with PU Code $ 701.1.

70. Edison should be ordered to present in its next GRC a DSM comparison exhibit which sets forth the positions of all active DSM parties.

71. There is ample precedent for Commission authority to penalize utilities by reduction of rate of return.

72. The ROE penalties proposed by DRA would not unfairly duplicate other penalties.

73. Commission instructions in D.82-01-103 and D.88-12-063 set clear standards for provision of information on nonstandard affiliate QF contracts.

74. A reduction in authorized ROE is not the most effective penalty for failure to provide information.

75. In Commission applications, failure to provide information is fundamentally a failure to meet the burden of proof.

76. In the KRCC reasonableness review and the merger proceeding Edison has not met the clear standards of behavior for provision of information.

77. Commission instructions in D.82-01-103 set clear standards for evaluation of nonstandard QF contracts.

78. The record in this proceeding should remain open to consider the Commission's decision on reasonableness issues in A.89-05-064, A.90-06-001, and A.91-05-050, and the impact of those issues on DRA's proposed penalty for favoritism.

79. Edison's obligations to bargain in good faith with QFs include the obligation to inform all QFs of terms and conditions that Edison has made available to other QFs, affiliated or nonaffiliated.

80. Edison's proposed semiannual report to the Commission would not fulfill that obligation.

81. Edison should be ordered to serve additional testimony in its current consolidated ECAC reasonableness reviews, on: (1) incremental base rate O&M costs of shortening refueling outages, and (2) incremental replacement power costs associated with extending refueling outages. DRA should have the opportunity to serve responsive testimony.

82. This decision should become effective today, so that test year revenue requirement will become effective January 1, 1992.

FOURTH INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) shall, on or before December 26, 1991, file with this Commission revised tariff sheets which:

a. revise its Authorized Level of Base Rate Revenue as set forth in Appendix D to this decision;

b. revise its Preliminary Statement to include the shared savings incentive program authorized in this decision; and

c. make other revisions as necessary to comply with this interim order.

2. The revised tariff pages shall become effective January 1, 1992 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. Edison shall incorporate the revised Authorized Level of Base Rate Revenue into rates ordered in the revenue requirement phase of Application 91-05-050.

4. Edison's rate recovery of operational and maintenance expenses related to San Onofre Nuclear Generating Station, Unit 1 shall be subject to refund, effective at the end of fuel cycle 11.

5. For Phase 1 purposes, the test year sales, customers, and present rate revenues set forth in Appendix B to this decision are adopted.

6. The labor and nonlabor escalation factors set forth in Appendix C to this decision are adopted.

7. The savings attributed to Edison's Cost Containment programs are split equally between shareholders and ratepayers, and rates are reduced by $37.4 million as set forth in Appendix C.

8. The test year marginal costs set forth in Appendix F to this decision are adopted, subject to revision for fuel prices adopted in other Commission proceedings.

9. Edison is directed to again present a multifactor productivity analysis in its next General Rate Case, and as part of the analysis, Edison shall particularly demonstrate how the forecasted multifactor productivity gains are reflected in its test year revenue requirement requests.

10. Edison is authorized to request revenue requirement adjustments for attrition years 1993 and 1994, based on the revenue requirement calculations set forth in Appendix E to this decision.

11. Attrition year revenue requirements shall not include specific incremental capital costs which Edison has requested for informational services software; research, development, and demonstration activities; demand-side management programs; nuclear design documentation; or other capital items. Attrition year plant additions shall be determined by authorized formula only.

12. Edison shall not recover in rates any test year capitalized costs for informational services software or research, development, and demonstration activities.

13. Edison may file additional information on the merits of capitalizing software within 120 days of the effective date of this order, and parties may reply within 120 days of Edison's filing.

14. Effective on the date that the proposed sale of the Yuma Axis Generating Station to Imperial Irrigation District is completed, Edison shall:

a. remove from Authorized Level of Base Rate Revenue the operations and maintenance expenses for the plant;

b. remove from Authorized Level of Base Rate Revenue the capital-related expenses for the plant; and

c. remove from rate base the plant in service and depreciation reserve for the plant.

15. In 1993 and 1994 Edison shall not recover Women and Minority Business Enterprise expenses which are authorized for 1992 in this decision. Expenses for those years shall be recovered by separate application in a generic proceeding.

16. Edison shall cease debiting its Women and Minority Business Enterprise memorandum account for clearinghouse expenses.

17. Edison's rate recovery of disputed property taxes related to <u>Arizona Public Service Company vs. Maricopa County</u> shall be

subject to refund. Edison shall record those expenses in an interest-bearing memorandum account pending the outcome of the lawsuit. After the lawsuit is finally resolved, Edison shall seek disposition of the account balance by advice filing. If Edison should prevail in the lawsuit, Edison shall return any property tax refunds to ratepayers.

18. Edison is authorized to establish an interest-bearing memorandum account to record the capital-related revenue requirement for the transmission line and related facility costs allocated to California Energy Company in D.90-09-059. If the disputed capital costs are eventually and finally reassigned to Edison, it may seek recovery of the memorandum account balance and future revenue requirement related to the reassigned plant.

19. Edison is authorized to include test year deferred debits for nuclear design documentation in rate base.

20. Edison is authorized to file in this proceeding additional information to substantiate its request for capitalization of RD&D projects which receive expense treatment at this time. Edison's filing must be in accordance with the standards for case-by-case exceptions to our general principles for capitalization of RD&D projects as explained in D.83-12-068. In addition, Edison must provide a full showing on the precise amounts of capitalization for each project along with detailed accounting on each project. The request must indicate whether the amounts being requested for capitalization are net book values of depreciated assets or original costs. Edision is authorized to file this information on or before December 31, 1992, and parties may file responses to Edison's filing within 120 days.

21. The conditions on electric transportation program scope, reporting, and fund shifting set forth in paragraphs 3, 5, 6, 7, and 8 of Exhibit 112 in this proceeding are adopted.

22. In its next GRC expense forecasts, Edison shall remove $13.449 million in historical expenses for electric transportation under RD&D.

23. For ratemaking purposes, Edison shall remove from plant in service $32.960 million for incomplete plant modifications at San Onofre Nuclear Generating Station, Unit 1.

24. Edison is authorized to return $32.960 million to plant in service upon a showing that the plant modifications considered in Decision 85-12-024 for San Onofre Nuclear Generating Station, Unit 1 have been completed. Edison may file that showing as a petition for modification in this proceeding.

25. Edison is authorized to make a filing, in this proceeding, to make a showing as to the cost-effectiveness of previously unjustified SONGS 1 costs for any NRC replacement work done during fuel cycles 9, 10, and 11 which were attributed to the cost cap set forth in D.85-12-024.

26. Edison is authorized to shift program funds for research, development, and demonstration activities and for demand-side management programs, as discussed in Chapters 8 and 11 in this decision.

27. Edison shall undergo a financial audit of its 1988 through 1992 research, development, and demonstration activities. The audit shall be coordinated by the Commission Advisory and Compliance Division, at Edison's expense. A final report shall be completed on or before June 30, 1993.

28. Edison shall establish an interest-bearing memorandum account to record all royalties, licensing fees, and other revenues attributable to its research, development, and demonstration programs. The account balance shall be returned to ratepayers in Edison's next general rate case.

29. Edison is authorized to include in its Major Additions Adjustment Clause a project to install selective catalytic

reduction technology at Alamitos Generating Station, Unit 6, as discussed in Chapter 9 in this decision.

30. Edison's authority for memorandum account treatment of hazardous waste expenses, ordered in D.87-12-066, D.89-01-039, and D.89-09-019, shall be extended through December 31, 1994. This authority shall include memorandum account treatment of expenses to comply with pending storm water discharge regulations promulgated by the U.S. Environmental Protection Agency.

31. Edison shall perform a study to separate marginal transformer costs into minimum costs for transmission or distribution functions and additional costs incurred to reduce overall system expenses. Edison shall deliver a report on the results of the study to the parties which submitted marginal cost testimony in Phase 1 of this proceeding, on or before June 30, 1992.

32. Ordering Paragraph 36 of Decision 87-12-066 is rescinded.

33. In future general rate cases, Energy Cost Adjustment Clause applications, and related proceedings, the Director of the Commission Advisory and Compliance Division shall determine the need and scheduling for workshops 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 necessary to calculate incremental energy rates for use in marginal cost or qualifying facility payment calculations. The workshops shall also serve as a forum in which the parties to the proceeding can agree, to the extent possible, on the assumptions to be used and the appropriate sources of the assumptions. If the Director determines that a workshop is necessary, the Director shall appoint a workshop coordinator, who will be the final arbiter of disputes relating to a common data set.

34. In its March 1993 annual report on demand-side management, Edison shall report on the cost-effectiveness of its

test year residential energy audits and of its test year fuel substitution programs.

35. Edison shall submit in its next GRC, a detailed assessment of economic, environmental, any other claimed benefits for fuel substitution, load retention and load building programs should it seek to continue or expand these programs.

36. Edison shall include, in its next GRC, detailed environmental evaluations of the impact of the technologies it chooses to promote as described in this decision.

37. In its March 1993 annual DSM report, Edison shall submit a table indicating the source and amount of funding for CTAC.

38. Edison shall show the cost-effectiveness of all load retention/load building programs in its next GRC if it requests ratepayer funding.

39. Edison is authorized to recover from ratepayers incentive payments to shareholders based on the shared savings program set forth in Chapter 11 and Appendix G to this decision. Shareholder payments shall be made as debits to the Electric Revenue Adjustment Mechanism balancing account, by advice filing made on or before March 31 in the year following the year in which the incentive payments are earned. The advice filings shall include adequate information to support the requested incentive payments. If shared savings penalties are accrued, they shall be imposed by similar advice filings.

40. Edison shall file, within 60 days of the effective date of this decision, an advice letter seeking Commision approval of all data necessary to calculate total resource costs for all shared savings programs.

41. The record in this proceeding shall remain open to consider the Commission's decision on reasonableness issues in consolidated Applications 89-05-064, 90-06-001, and 91-05-050, and the impact of those issues on a proposed 20 basis point return on equity penalty for favoritism to affiliated qualifying facilities.

This matter shall be decided before Edison's next general rate case test year.

42. Edison shall serve additional testimony in consolidated Applications 89-05-064, 90-06-001, and 91-05-050 on: (1) incremental operations and maintenance costs of shortening nuclear power plant refueling outages, and (2) replacement power costs associated with extending refueling outages. The testimony shall be served in accordance with a schedule ordered by the assigned Administrative Law Judge in the consolidated proceedings.

43. Edison shall file its next general rate application for a 1995 test year, based on recorded operations through 1992. The application shall be processed according to the Rate Case Plan.

44. In its next general rate case, Edison shall file or serve testimony on the following topics:

a. wages and salaries, with increased emphasis on total compensation, total benefits as a percentage of cash compensation, and the distribution of total compensation among comparable firms;

b. an improved showing on productivity, including the influence of productivity on forecasts of operating and maintenance expenses;

c. a zone of reasonableness for nuclear operations and maintenance expenses;

d. optimization of nuclear plant refueling outage durations, including base rate and fuel-related expenses at San Onofre Nuclear Generating Station and Palo Verde Nuclear Generating Station;

e. nuclear power plant replacement generation insurance;

f. nuclear decommissioning trust fund earnings rate and contingency factor;

g. an improved showing on the ratemaking treatment of research, development, and demonstration activities;

h. management policies and practices for planning and approval of capital projects;

i. total expenditures for the high voltage direct current transmission line expansion project;

j. long run cost-effectiveness of utility demand-side management programs, with specific attention to "free riders" and to marketplace obstacles and progress toward overcoming them;

k. a comparison exhibit showing the positions of all parties on demand-side management issues, due on Day 206 of the Rate Case Plan; and

l. the percentage of administrative and general expenses within all proposed demand-side management programs.

45. In future general rate cases, Energy Cost Adjustment Clause applications, and other proceedings in which rates are revised, Edison shall file forecasts of off-system sales revenues and revenue consolidation tables similar to the tables in Exhibit 122 in this proceeding.

This order is effective today.

Dated December 20, 1991, at San Francisco, California.

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

PB

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

APPENDIX A
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List of Appearances

Applicant: Stephan E. Pickett, Carol B. Henningson, Frank A. McNulty, Carol A. Schmid-Frazee, Eugene E. Rodrigues, Frank J. Cooley, and Michael D. Mackness, Attorneys at Law, and O'Melveny & Myers, by Charles C. Read and Patricia Schmiege, Attorneys at Law, for Southern California Edison Company.

Interested Parties: Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Michael P. Alcantar and Mark P. Trinchero, Attorneys at Law, for Cogenerators of Southern California; Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Paul J. Kaufman, Attorney at Law, for Kern River Cogeneration; Barbara Barkovich, for Barkovich & Yap; Caryn J. Hough, Attorney at Law, for California Energy Commission; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth and Joseph S. Faber, Attorneys at Law, for California Large Energy Consumers Association; David R. Branchcomb, for Henwood Energy Services; Maurice Brubaker, for Drazen, Brubaker & Associates; Messrs. Kronick, Moscovitz, Tiedemann & Girard, by John L. Bukey, Attorney at Law, for School Committee to Reduce Utility Bills (SCRUB); Messrs. McCracken, Byers & Martin, by David J. Byers, Attorney at Law, for Cities of Oxnard and Irvine; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Nancy I. Day and David B. Follett, Attorney at Law, for Southern California Gas Company; Philip Di Virgilio, for Destec Energy, Inc.; Nancy W. Doyne, David R. Clark, and William L. Reed, Attorneys at Law, for San Diego Gas & Electric Company; Karen Edson, for KKE & Associates; Messrs. Grueneich, Ellison & Schneider, by Barry H. Epstein, Attorney at Law, for California Department of General Services; Michel P. Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization (TURN); Sam De Frawi, for the Department of the Navy; Norman J. Furuta, Attorney at Law, for Federal Executive Agencies; Messrs. Biddle & Hamilton, by Richard L. Hamilton, Attorney at Law, for Western Mobilhome Association; Melissa Metzler, for Barakat & Chamberlin; Karen N. Mills, Attorney at Law, for California Farm Bureau Federation; Jeff Nahigian, for JBS Energy, Inc.; Mike Nazemi and Barbara Baird, Attorney at Law, for the South Coast Air Quality Management District; John D. Quinley, for Cogeneration Service Bureau; James A. Ross, for Regulatory & Cogeneration Services; Bartle Wells Associates, by Reed V. Schmidt, for California City-County Street Light Association; Donald W. Schoenbeck, for Midway Sunset Cogeneration Company; Jan Smutny-Jones, for

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Independent Energy Producers; Messrs. Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Ronald Liebert, Attorneys at Law, for Industrial Users; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller & Associates; Ralph Cavanagh, Attorney at Law, for Natural Resources Defense Council; Messrs. Grueneich, Ellison & Schneider, by Dian M. Grueneich and Christopher Ellison, Attorneys at Law, for California Energy Coalition; Messrs. Morrison & Foerster, by Lynn Haug and Jerry Bloom, Attorneys at Law, for California Cogeneration Council; Kermit R. Kubitz, Roger Peters, and Harry W. Long, Jr., Attorneys at Law, for Pacific Gas and Electric Company; Jim Lerner and James Boyd, for California Air Resources Board; Sara Steck Myers, Attorney at Law, for California Energy Company; Messrs. Pillsbury, Madison & Sutro, by James N. Roethe, Attorney at Law, for Air Products & Chemicals Inc.; Donald G. Salow, for Association of California Water Agencies (ACWA); Douglas A. Ames, for Transphase Systems, Inc.; James Hodges, for The East Los Angeles Community Union, The Maravilla Foundation, and Veterans in Community Service.

Information Only: Peter Minkler, for IPT Corporation.

Division of Ratepayers Advocates: Kathleen Maloney, John S. Wong, and Jean Vieth, Attorneys at Law, and Donald Schultz.

State Service: Messrs. Greve, Clifford, Diepenbrock & Paras, by Matthew V. Brady, Attorney at Law, for Department of General Services; Dorothy Taylor, for Public Affairs Office; Paul W. Fassinger and Scarlett Liang Uejio, for Commission Advisory and Compliance Division; and Jeffrey Dasovich, for Division of Strategic Planning.

(END OF APPENDIX A)

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

SALES FORECASTS AND PRESENT RATE REVENUES

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Adopted Present Base Rate Revenues	2

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ADOPTED SALES AND CUSTOMER FORECASTS

Forecast	Edison Estimate	DRA Estimate	Adopted
	(a)	(b)	(c)
Sales Forecast (GWh)			
Five CPUC Major Customer Groups			
Domestic	22,499	22,703	22,703
Lighting-Small & Medium Power	25,104	25,408	25,408
Large Power	21,257	21,655	21,655
Agricultural & Pumping	2,108	2,247	2,136
Street & Area Lighting	471	472	472
Subtotal	71,439	72,485	72,374
Sequoia	1	1	1
Fringe	0	0	0
TOU-Resale	280	280	280
Resale-Special Contracts	1,440	1,440	1,440
Total Sales Forecast	73,160	74,206	74,095
Customer Forecast (No. of Customers)			
Five CPUC Major Customer Groups			
Domestic	3,589,266	3,553,721	3,553,721
Lighting-Small & Medium Power	528,915	528,072	528,072
Large Power	2,967	3,186	3,186
Agricultural & Pumping	26,850	27,152	27,152
Street & Area Lighting	23,503	24,068	24,068
Subtotal	4,171,501	4,136,199	4,136,199
Sequoia	1	1	1
Fringe	0	0	0
TOU-Resale	11	11	11
Resale-Special Contracts	13	13	13
Total Customer Forecast	4,171,526	4,136,224	4,136,224

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
Total Company
Test Year 1992
ADOPTED PRESENT BASE RATE REVENUES
(Thousands of 1992 Dollars)

Customer Group	Adopted
Five CPUC Major Customer Groups	
Domestic	$1,427,998
Lighting-Small & Medium Power	1,496,314
Large Power	930,701
Agricultural & Pumping	114,400
Street & Area Lighting	54,826
Total CPUC Customer Groups	$4,024,239
Sequoia 1/	15
Fringe 2/	0
TOU-Resale 3/	5,000
Resale-Special Contracts 4/	0
Subtotal	$4,029,254
Other Operating Revenues 5/	107,712
Grand Total	$4,136,966

1/ Retail sales contract to Sequoia National Park (Schedule A-6).
2/ Off system sales to other utilities at Edison's boundaries.
3/ Resales to 12 cities under FERC tariffs.
4/ Off system sales contracts to cities and other utilities. Forecast non-fuel revenues are used to reduce the ERAM balancing rate, instead of crediting against base rate revenue requirement.
5/ Revenues received from other than sales of electricity (FERC Accounts 451-456). Of this amount, $107,628,000 is CPUC jurisdictional, the remaining $84,000 is FERC jurisdictional.

(END OF APPENDIX B)

APPENDIX C

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
ADOPTED ESCALATION RATES
(Base Year 1988)

1. Adopted Escalation Rates Excluding Cost Containment:

	Labor		Nonlabor	
Year	Rate	Index	Rate	Index
1988	-	100.00	-	100.00
1989	3.43%	103.43	4.08%	104.08
1990	3.47%	107.02	4.16%	108.40
1991	3.90%	111.19	3.16%	111.82
1992	4.16%	115.81	2.91%	115.07

2. Adopted Escalation Indices Including Cost Containment:

	Labor		Nonlabor	
Year	Rate	Index	Rate	Index
1988	-	100.00	-	100.00
1989	-	102.65	-	103.30
1990	-	105.42	-	106.78
1991	-	108.71	-	109.32
1992	-	112.37	-	111.65

3. Adopted Cost Containment:

	Cost Containment	
Year	Rate	Index
1988	-	100.00
1989	0.75%	99.25
1990	0.75%	98.51
1991	0.75%	97.77
1992	0.75%	97.03

(END OF APPENDIX C)

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

RESULTS OF OPERATION

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APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
CALCULATION OF FRANCHISE FEES AND UNCOLLECTIBLES

Description	Adopted
Uncollectibles	
Present Rate Revenues - Five Cust. Group	$4,024,239
Uncollectible Rate	0.2080%
Total Uncollectibles	$8,370
Franchise Requirements	
Present Rate Revenues - Five Cust. Group & Resales	$4,029,254
Franchise Fee Rate	0.7877%
Total Franchise Fees	$31,738

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
TOTAL PRODUCTION EXPENSE
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Description	Adopted
Operation	
Steam	$69,173
Nuclear	124,906
Hydroelectric	9,451
Other	4,463
Total Operation	$207,993
Maintenance	
Steam	136,289
Nuclear	102,308
Hydroelectric	9,717
Other	13,585
Total Maintenance	$261,899
TOTAL PRODUCTION (1988$)	$469,892
Escalation Amounts, 1988 to 1992 1/	
Labor	24,850
Non-Labor	29,076
Other 2/	(577)
Total	$53,349
TOTAL PRODUCTION (1992$)	$523,241

1/ Including Cost Containment.
2/ Cost Containment only.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
STEAM PRODUCTION EXPENSE
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
500.0	Supervision and Engineering	$8,443
501.0	Fuel Related Expenses	22,748
502.0	Steam Expenses	19,971
505.0	Electric Expenses	5,276
506.0	Misc. Steam Power Expenses	12,529
507.0	Rents	206
	Total Operation	$69,173
	Maintenance	
510.0	Supervision and Engineering	19,226
511.0	Structures	7,569
512.0	Boiler Plant	60,355
513.0	Electric Plant	34,635
514.0	Miscellaneous Steam Plant	14,504
	Total Maintenance	$136,289
	TOTAL STEAM PRODUCTION (1988$)	$205,462
	Escalation Amounts, 1988 to 1992 1/	
	Labor	8,510
	Non-Labor	15,012
	Other 2/	(232)
	Total	$23,290
	TOTAL STEAM PRODUCTION (1992$)	$228,752

1/ Including Cost Containment.
2/ Cost Containment only.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
NUCLEAR PRODUCTION EXPENSE
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted 1/
	Operation	
517.0	Supervision and Engineering	$50,631
519.0	Coolants and Water	5,251
520.0	Steam Expenses	17,554
523.0	Electric Expenses	1,627
524.0	Misc. Nuclear Power Expenses	49,041
525.0	Rents	803
	Total Operation	$124,906
	Maintenance	
528.0	Supervision and Engineering	25,786
529.0	Structures	14,674
530.0	Reactor Plant Equipment	27,673
531.0	Electric Plant	14,665
532.0	Miscellaneous Nuclear Plant	19,509
	Total Maintenance	$102,308
	TOTAL NUCLEAR PROD. (1988$)	$227,214
	Escalation Amounts, 1988 to 1992 2/	
	Labor	14,185
	Non-Labor	11,757
	Other 3/	(345)
	Total	$25,597
	TOTAL NUCLEAR PROD. (1992$)	$252,811

1/ Reflects 2 refueling outages for SONGS, and 2 for Palo Verde for Test Year 1992. Adopted average costs per outage (1992$) are $15,657,000 for SONGS and $3,648,000 for Palo Verde (see Appendix D, page 31).
2/ Including Cost Containment.
3/ Cost Containment only.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
HYDROELECTRIC PRODUCTION EXPENSE
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
535.0	Supervision and Engineering	$2,379
536.0	Water for Power	1,199
537.0	Hydroelectric Expenses	1,536
538.0	Electric Expense	2,061
539.0	Misc. Hydro Expense Generation	1,634
540.0	Rents	642
	Total Operation	$9,451
	Maintenance	
541.0	Supervision and Engineering	1,362
542.0	Structures	1,188
543.0	Reservoirs, Dams and Waterways	2,184
544.0	Maintenance of Electric Plant	3,445
545.0	Miscellaneous Hydroelectric Plant	1,538
	Total Maintenance	$9,717
	TOTAL HYDRO PRODUCTION (1988$)	$19,168
	Escalation Amounts, 1988 to 1992 1/	
	Labor	1,349
	Non-Labor	963
	Other 2/	0
	Total	$2,312
	TOTAL HYDRO PRODUCTION (1992$)	$21,480

1/ Including Cost Containment.
2/ Cost Containment only.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
OTHER POWER PRODUCTION EXPENSE
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
546.0	Supervision and Engineering	$1,097
548.0	Generation Expenses	2,495
549.0	Misc. Other Power Expenses	860
550.0	Rents	11
	Total Operation	$4,463
	Maintenance	
551.0	Supervision and Engineering	1,201
552.0	Maintenance of Structures	856
553.0	Maintenance of Electric Plant	9,927
554.0	Misc. Other Power Gen. Plant	1,601
	Total Maintenance	$13,585
	TOTAL OTHER PRODUCTION (1988$)	$18,048
	Escalation Amounts, 1988 to 1992 1/	
	Labor	806
	Non-Labor	1,344
	Other 2/	0
	Total	$2,150
	TOTAL OTHER PRODUCTION (1992$)	$20,198

1/ Including Cost Containment
2/ Cost Containment only

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
TRANSMISSION EXPENSE
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
560.0	Supervision and Engineering	$6,227
561.0	Load Dispatching	3,985
562.0	Station Expenses	15,678
563.0	Overhead Line Expenses	1,116
564.0	Underground Line Expenses	110
565.0	Trans. of Elect. By Others	8,928
566.0	Misc. Transmission Expenses	3,848
567.0	Rents	593
	Total Operation	$40,485
	Maintenance	
568.00	Supervision and Engineering	4,256
569.00	Structures	2,176
570.00	Station Equipment	9,563
571.00	Overhead Lines	9,956
572.00	Underground Lines	102
573.00	Misc. Transmission Plant	3,716
	Total Maintenance	$29,769
	TOTAL TRANSMISSION (1988$)	$70,254
	Escalation Amounts, 1988 to 1992 1/	
	Labor	4,872
	Non-Labor	2,556
	Other 2/	(265)
	Total	$7,163
	TOTAL TRANSMISSION (1992$)	$77,417

1/ Including Cost Containment.
2/ Cost Containment only.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
DISTRIBUTION EXPENSE
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Operation	
580.0	Supervision and Engineering	$18,519
582.0	Station Expenses	10,120
583.0	Overhead Line Expenses	7,632
584.0	Underground Line Expenses	4,345
585.0	Street Lighting & Signal Sys.	954
586.0	Meter Expenses	13,760
587.0	Customer Installations	10,029
588.0	Misc. Distribution Expenses	15,802
589.0	Rents	2,194
	Total Operation	$83,355
	Maintenance	
590.00	Supervision and Engineering	11,336
591.00	Structures	3,478
592.00	Station Equipment	7,150
593.00	Overhead Services	23,862
594.00	Underground Lines	8,658
595.00	Line Transformers	3,619
596.00	Street Lighting & Signal Sys.	2,053
597.00	Meters	1,976
598.00	Misc. Distribution Plant	15,088
	Total Maintenance	$77,220
	TOTAL DISTRIBUTION (1988$)	$160,575
	Escalation Amounts, 1988 to 1992 1/	
	Labor	11,982
	Non-Labor	7,423
	Other 2/	0
	Total	$19,404
	TOTAL DISTRIBUTION (1992$)	$179,979

1/ Including Cost Containment.
2/ Cost Containment only.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
CUSTOMER ACCOUNTS EXPENSE
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
901.0	Supervision	$6,628
902.0	Meter Reading Expenses	26,140
903.0	Customer Records and Collectibles	73,949
904.0	Uncollectible Accounts	8,370
905.0	Misc. Customer Accounts Exp.	2,556
	TOTAL CUSTOMER ACCTS. (1988$)	$117,643
	Total (Less Uncollectibles)	$109,273
	Escalation Amounts, 1988 to 1992 1/	
	Labor	8,738
	Non-Labor	2,796
	Other	0
	Total	$11,534
	TOTAL CUSTOMER ACCTS. (1992$)	$129,178
	Total (Less Uncollectibles)	$120,807

1/ Including Cost Containment
except for postages and uncollectibles in
Acct.903 and 904.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES
(Thousands Of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description	Adopted
	Residential & Non-Residential Conservation, Service Planning, and Load Management Expenses	
907.0	Supervision	$2,641
908.0	Customer Assistance Expense	129,320
909.0	Informational & Instruct. Exp.	8,171
910.0	Miscellaneous	0
	TOTAL CUSTOMER SERVICES AND INFORMATIONAL (1988$)	$140,132
	Escalation Amounts, 1988 to 1992 1/	
	Labor	3,805
	Non-Labor	9,530
	Other	0
	Total	$13,335
	TOTAL CUSTOMER SERVICES AND INFORMATIONAL (1992$)	$153,467

1/ Excluding Cost Containment.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
ADMINISTRATIVE & GENERAL EXPENSES
(Thousands of 1988 Dollars Unless Otherwise Indicated)

Account No.	Description		Adopted
	Operation		
920.0	Administrative & Gen. Salaries		$116,220
921.0	Office Supplies and Expenses		28,588
922.0	Admin. & Gen. Transfer Credit		(28,643)
923.0	Outside Services Employed		5,734
924.0	Property Insurance		17,053
925.0	Injuries and Damages		27,137
926.0	Pensions and Benefits-Total		151,611
926.1	Pensions & Benefits-Health Care	$85,942	
926.2	Pensions & Benefits-Non-Health C.	65,668	
927.0	Franchise Requirements		31,738
928.0	Regulatory Commission Expenses		2,655
930.0	Misc. General Expenses - Total		49,969
930.1	General Advt. Expense	501	
930.2	Other Misc. General Expenses	49,468	
	- RD&D	48,714	
931.0	Rents		2,729
	Total Operation		$404,791
	Maintenance		
935.0	Maintenance of General Plant		13,528
	Total Maintenance		13,528
	TOTAL ADMIN. & GEN. (1988$)		$418,319
	Total (Less Franchise Req.)		$386,580
	Escalation Amounts, 1988 to 1992 1/		
	Labor		14,845
	Non-Labor		13,657
	Other		(2,853)
	Total		$25,648
	TOTAL ADMIN. & GEN. (1992$)		$443,967
	Total (Less Franchise Req.)		$412,229

1/ Including Cost Containment except for Health Care, Franchise Fees, and RD&D.

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
EXPENSE SUMMARY
(Thousands of 1988 Dollars Unless Otherwise Indicated)

Description		Adopted
TOTAL NON-ESCALATED		
Steam Production	$205,462	
Nuclear Production	227,214	
Hydroelectric Production	19,168	
Other Production	18,048	
Total Production		$469,892
Transmission		70,254
Distribution		160,575
Customer Accounts		117,643
Customer Service & Informational		140,132
Administrative and General		418,319
Additional Productivity		0
Total Non-Escalated (1988$)		$1,376,815
TOTAL ESCALATED		
Steam Production	228,752	
Nuclear Production	252,811	
Hydroelectric Production	21,480	
Other Production	20,198	
Total Production		$523,241
Transmission		77,417
Distribution		179,979
Customer Accounts		129,178
Customer Service & Informational		153,467
Administrative and General		443,967
Additional Productivity		0
Total Escalated (1992$)		$1,507,249
TOTAL ESCALATION (1988$ to 1992$)		
Steam Production	23,290	
Nuclear Production	25,597	
Hydroelectric Production	2,312	
Other Production	2,150	
Total Production		$53,349
Transmission		7,163
Distribution		19,404
Customer Accounts		11,534
Customer Service & Informational		13,335
Administrative and General		25,648
Additional Productivity		0
Total Escalation		$130,433

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
LABOR SUMMARY
(Thousands of 1988 Dollars Unless Otherwise Indicated)

Description		Adopted
LABOR NON-ESCALATED (1988$)		
Steam Production	$68,796	
Nuclear Production	114,669	
Hydroelectric Production	10,904	
Other Production	6,513	
Total Production		$200,882
Transmission		39,384
Distribution		96,861
Customer Accounts		70,638
Customer Service & Informational		24,064
Administrative and General		116,772
Additional Productivity		0
Total Non-Escalated Labor		$548,601
LABOR ESCALATED (1992$)		
Steam Production	77,306	
Nuclear Production	128,854	
Hydroelectric Production	12,253	
Other Production	7,319	
Total Production		$225,732
Transmission		44,256
Distribution		108,843
Customer Accounts		79,376
Customer Service & Informational		27,869
Administrative and General		131,617
Additional Productivity		0
Total Escalated Labor		$617,692
LABOR ESCALATION (1988$ to 1992$)		
Steam Production	8,510	
Nuclear Production	14,185	
Hydroelectric Production	1,349	
Other Production	806	
Total Production		$24,850
Transmission		4,872
Distribution		11,982
Customer Accounts		8,738
Customer Service & Informational		3,805
Administrative and General		14,845
Additional Productivity		0
Total Labor Escalation		$69,091

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
NON-LABOR SUMMARY
(Thousands of 1988 Dollars Unless Otherwise Indicated)

Description		Adopted
NON-LABOR NON-ESCALATED (1988$)		
Steam Production	$128,855	
Nuclear Production	100,920	
Hydroelectric Production	8,264	
Other Production	11,535	
Total Production		$249,574
Transmission		21,942
Distribution		63,714
Customer Accounts		24,002
Customer Service & Informational		63,239
Administrative and General		102,131
Additional Productivity		0
Total Non-Escalated Non-Labor		$524,602
NON-LABOR ESCALATED (1992$)		
Steam Production	143,867	
Nuclear Production	112,677	
Hydroelectric Production	9,227	
Other Production	12,879	
Total Production		$278,650
Transmission		24,498
Distribution		71,137
Customer Accounts		26,798
Customer Service & Informational		72,769
Administrative and General		115,788
Additional Productivity		0
Total Escalated Non-Labor		$589,640
NON-LABOR ESCALATION (1988$ to 1992$)		
Steam Production	15,012	
Nuclear Production	11,757	
Hydroelectric Production	963	
Other Production	1,344	
Total Production		$29,076
Transmission		2,556
Distribution		7,423
Customer Accounts		2,796
Customer Service & Informational		9,530
Administrative and General		13,657
Additional Productivity		0
Total Non-Labor Escalation		$65,038

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
OTHER SUMMARY
(Thousands of 1988 Dollars Unless Otherwise Indicated)

Description		Adopted
OTHER NON-ESCALATED (1988$)		
Steam Production	$7,811	
Nuclear Production	11,625	
Hydroelectric Production	0	
Other Production	0	
Total Production		$19,436
Transmission		8,928
Distribution		0
Customer Accounts		23,003
Customer Service & Informational		52,829
Administrative and General		199,415
Additional Productivity		0
Total Non-Escalated Other		$303,612
OTHER ESCALATED (1992$)		
Steam Production	7,579	
Nuclear Production	11,280	
Hydroelectric Production	0	
Other Production	0	
Total Production		$18,859
Transmission		8,663
Distribution		0
Customer Accounts		23,003
Customer Service & Informational		52,829
Administrative and General		196,562
Additional Productivity		0
Total Escalated Other		$299,917
OTHER ESCALATION (1988$ to 1992$)		
Steam Production	(232)	
Nuclear Production	(345)	
Hydroelectric Production	0	
Other Production	0	
Total Production		($577)
Transmission		(265)
Distribution		0
Customer Accounts		0
Customer Service & Informational		0
Administrative and General		(2,853)
Additional Productivity		0
Total Other Escalation		($3,695)

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
TAXES OTHER THAN ON INCOME
(Thousands of 1992 Dollars)

Description	Adopted
Ad Valorem Taxes	
Ca., Ariz., N.M., Nev. & D.C.	$152,809
Total Ad Valorem Taxes	152,809
Payroll Taxes	
Federal Insurance Contrib. Act (FICA)	44,755
Federal Unemployment Insurance	787
State Unemployment Insurance	644
Total Payroll Taxes	46,186
Miscellaneous Taxes	
Superfund Tax	1,528
Miscellaneous Taxes	(399)
Total Miscellaneous Taxes	1,129
Total Taxes OTOI (1992$)	$200,124

Superfund Tax Calculation

Federal Taxable Income (excl. Superfund Tax)	$956,446
Plus:	
ACE Adjustment	318,419
Tax Preferences	260
Alt. Min. Taxable Income	1,275,125
Superfund Exclusion	(2,000)
Superfund Taxable Income	$1,273,125
Superfund Tax Rate	0.12%
Superfund Tax	$1,528

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
INCOME TAX ADJUSTMENTS
(Thousands of 1992 Dollars)

Description	Adopted
California Income Tax Adjustments	
Tax Depreciation (liberalized)	$725,993
Nuclear Fuel Amort. (liberalized)	(74,902)
Fuel Oil Transp. Fac. (liberalized)	(6,479)
Interest on Long-Term Debt	475,750
Interest on Accumulated ITC	(19,132)
CIAC Revenues	7,606
Non-Deductible Business Meals	(390)
Ad Valorem Lien Date Adjust.	2,252
Removal Costs	42,837
Right of Way Easement Amort.	1,565
Repair Allowance	26,685
Salvage Warehouse Exp.	468
ACE Limited Insurance	(903)
Superfund Tax (ACE)	(1,528)
	$1,179,822
Federal Income Tax Adjustments	
Tax Depreciation (liberalized)	876,147
Nuclear Fuel Amort. (liberalized)	(73,521)
Fuel Oil Transp. Fac. (liberalized)	(6,479)
Interest on Long-Term Debt	475,750
CIAC-Taxable Income	(42,552)
Non-Deductible Business Meals	(390)
Ad Valorem Lien Date Adjust.	2,252
Removal Costs	25,719
Right of Way Easement Amort.	1,545
Repair Allowance	17,325
Salvage Warehouse Exp.	468
ACE Limited Insurance	(903)
Preferred Dividend Credit	832
	$1,276,193

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
TAXES ON INCOME - PRESENT RATES
(Thousands of 1992 Dollars)

Description	Adopted
California Corporation Franchise Tax	
Operating Revenues	$4,136,966
Operating Expenses	1,509,071
Nuclear Decommissioning Exp. (Qualified)	83,883
Taxes Other Than on Income	200,124
State Income Tax Adjustments	1,179,822
California Taxable Income	$1,164,067
CCFT Tax Rate	8.7251%
TOTAL CCFT	$101,566
Federal Income Tax	
Operating Revenues	$4,136,966
Operating Expenses	1,509,071
Nuclear Decommissioning Exp. (Qualified)	83,883
Taxes Other Than on Income	200,124
CCFT (1991)	110,452
State Income Tax (Ariz & NM)	2,325
Federal Income Tax Adjustments	1,276,193
Federal Taxable Income	$954,919
FIT Tax Rate	34.00%
Federal Income Tax	$324,672
Ariz. & NM State Income Tax	
California Taxable Income	$1,164,067
Arizona Tax Rate	0.1641%
New Mexico Tax Rate	0.0356%
Total Rate	0.1997%
Ariz. & NM Income Tax	$2,325
Income Tax Deferred	$94,100
Investment Tax Credit - Deferred	($18,540)
Total Taxes on Income	$504,123

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
DEPRECIATION EXPENSE
(Thousands of 1992 Dollars)

Description	Adopted
Depreciation Expense	
Steam Production	$102,300
Nuclear Production	201,201
Hydroelectric Production	11,242
Other Production	11,973
Transmission	60,888
Distribution	202,754
General	52,220
Experimental Plant	5,688
Subtotal	$648,266
Deferred Debit	3,369
Nuclear decommissioning	96,325
DSM Capital Program	43
Total Depreciation Expense	$748,003

Depreciation Expense Charged to Other Accounts

Other Depreciation (General)	1,761
Fuel Oil Transportation Facility	6,462
Total Depreciation Expense	$8,223

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
DEPRECIATION RESERVE
(Thousands of 1992 Dollars)

Description	Adopted
Depreciation Reserve - Wtd. Avg.	
Steam Production	$1,268,091
Nuclear Production	1,480,060
Hydroelectric Production	149,769
Other Production	239,270
Transmission	829,594
Distribution	1,783,770
General	250,350
Experimental Plant	18,929
	$6,019,834
Retirement Work-in-Progress	(46,556)
Other Depreciable	
Other Depr. (General)	9,826
Fuel Oil Transp. Facilities	65,171
Total Depreciation Reserve: Wtd. Avg.	$6,048,275

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
PLANT IN SERVICE - EOY
(Thousands of 1992 Dollars)

Description	Adopted
Plant in Service - BOY	
Intangible	$113
Production Plant	
Steam	2,116,742
Nuclear	5,885,827
Hydroelectric	570,551
Other	401,616
Total Production	$8,974,736
Transmission Plant	2,542,896
Distribution Plant	5,452,556
General Plant	1,006,587
Total Plant in Service - BOY	$17,976,888
Plant in Service - Net Additions	
Intangible	$0
Production Plant	
Steam	78,820
Nuclear	75,825
Hydroelectric	7,682
Other	1,463
Total Production	$163,789
Transmission Plant	86,163
Distribution Plant	355,907
General Plant	75,043
Total Net Additions	$680,902
Plant in Service - EOY	
Intangible	$113
Production Plant	
Steam	2,195,562
Nuclear	5,961,652
Hydroelectric	578,233
Other	403,079
Total Production	$9,138,525
Transmission Plant	2,629,059
Distribution Plant	5,808,463
General Plant	1,081,630
Total Plant in Service - EOY	$18,657,790

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
PLANT IN SERVICE - Weighted Average
(Thousands of 1992 Dollars)

Description	Adopted
Plant in Service - BOY	
Intangible	$113
Production Plant	
Steam	2,116,742
Nuclear	5,885,827
Hydroelectric	570,551
Other	401,616
Total Production	$8,974,736
Transmission Plant	2,542,896
Distribution Plant	5,452,556
General Plant	1,006,587
Total Plant in Service - BOY	$17,976,888
Plant in Service - Weighted Average Net Additions	
Intangible	$0
Production Plant	
Steam	33,506
Nuclear	41,491
Hydroelectric	2,641
Other	948
Total Production	$78,587
Transmission Plant	38,084
Distribution Plant	176,233
General Plant	32,134
Total Wtd. Avg. Net Additions	$325,037
Total Plant in Service - Weighted Average	
Intangible	$113
Production Plant	
Steam	2,150,248
Nuclear	5,927,318
Hydroelectric	573,192
Other	402,564
Total Production	$9,053,323
Transmission Plant	2,580,980
Distribution Plant	5,628,789
General Plant	1,038,721
Total Plant in Service - Wtd. Avg.	$18,301,925

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
PLANT HELD FOR FUTURE USE
(Thousands of 1992 Dollars)

Description	Adopted
Plant Held for Future Use - BOY	
Intangible	$0
Production Plant	
Steam	0
Nuclear	688
Hydroelectric	842
Other	0
Total Production	$1,530
Transmission Plant	18,810
Distribution Plant	12,723
General Plant	3,716
Total Plant Held for Future Use : BOY	$36,779
PHFU - Wtd. Avg. Net Additions	
Intangible	0
Production Plant	
Steam	0
Nuclear	0
Hydroelectric	0
Other	0
Total Production	$0
Transmission Plant	169
Distribution Plant	239
General Plant	250
Total Wtd. Avg. Net Additions	$659
Plant Held for Future Use - Weighted Average	
Intangible	$0
Production Plant	
Steam	0
Nuclear	0
Hydroelectric	688
Other	842
Total Production	$1,530
Transmission Plant	18,979
Distribution Plant	12,962
General Plant	3,966
Total PHFU: Wtd. Avg.	$37,438

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
RATE BASE
(Thousands of 1992 Dollars)

Description	Adopted
FIXED CAPITAL - Weighted Average	
Plant in Service	$18,301,925
PHFU	37,438
Total Fixed Capital - Wtd. Avg.	$18,339,363
ADJUSTMENTS	
Deferred Debits	69,602
Cust. Adv. for Construction	(86,090)
Total Adjustments	($16,488)
WORKING CAPITAL	
Materials & Supplies	102,037
Working Cash	36,630
Total Working Capital	$138,667
Tot. Before Ded. for Reserves	$18,461,542
DEDUCTIONS FOR RESERVES	
Wtd. Avg. Depreciation Reserve	(6,048,275)
Taxes Def. - ACRS/MACRS	(1,393,277)
Taxes Def. - Capitalized Interest	17,368
Taxes Def. - CIAC	44,785
Unfunded Pension Reserve	(73,496)
Total Ded. for Reserves	($7,452,895)
Wtd. Avg. Depreciated Rate Base	$11,008,647
Plus: DSM Amort. & Capital Program	29,633
Total Depreciated Rate Base: Wtd. Avg.	$11,038,280

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
DETERMINATION OF AVERAGE AMOUNTS OF WORKING
CASH CAPITAL SUPPLIED BY INVESTORS
(Thousands of 1992 Dollars)

Description	Adopted
Operational Cash Requirements	
Cash	$0
Special Deposits	320
Working Funds	2,772
Prepayments	12,910
Other Accounts Receivable	29,911
Total	$45,913
Less: Amounts Not Supplied By Investors	
Accrued Vacation & Empl. Witholdings	48,841
Credit recd. for Capitlized Supplies	22,555
User Taxes	12,629
Total	$84,025
Total Operational Cash Requirement	($38,112)
Plus: Average Amount Required	
Average Amount of Working Cash Capital Required as a Result of Paying Expenses in Advance of Collecting Revenues	74,742
Average Net Amount of Working Cash Capital Supplied by Investors	$36,630

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES
(Thousands of 1992 Dollars)

Description	Expense	Average Lag Days	Product
FUEL:	(A)	(B)	(C=AxB)
Fuel Oil	$52,532	24.67	1,295,964
Gas Purchase	598,143	38.69	23,142,153
Coal	129,744	32.49	4,215,383
Nuclear Fuel-Amt.	98,891	0.00	0
Nuclear Fuel-Other	22,368	75.60	1,691,021
Purchased Power	2,370,142	42.28	100,209,604
Subtotal	$3,271,820	39.90	$130,554,124
OTHER OPERATING EXP:			
Company Labor	617,692	12.00	7,412,307
Goods and Services	586,449	30.30	17,769,420
Materials From Storeroom	52,699	0.00	0
Property Insurance	43,649	0.00	0
Injuries and Damages	25,655	0.00	0
Pension Expense	142,817	0.00	0
Franchise Reqt.	58,534	268.51	15,716,834
Subtotal	$1,527,496	26.77	$40,898,561
Depreciation	748,003	0.00	0
TAXES-OTHER THAN INCOME:			
Ad Valorem Tax - All	152,809	72.02	11,004,705
FICA	44,755	16.43	735,329
Unemp. Tax - Fed.	787	76.89	60,503
Unemp. Tax - Cal.	550	72.65	39,952
Misc. Taxes - Fed.	(818)	0.00	0
Misc. Taxes - Cal.	128	0.00	0
Misc. Local Tax	179	0.00	0
Hazardous Waste	1,720	181.50	312,127
Subtotal	$200,110	60.73	$12,152,616
TAXES-INCOME			
Fed. Income Tax	320,698	126.24	40,484,911
Income Tax Deferred	94,100	0.00	0
Investment Tax Credit	0	126.24	0
State Income Tax - Cal.	100,543	122.53	12,319,511
State Income Tax-Ari. & NM	2,301	84.44	194,315
Subtotal	$517,642	102.38	$52,998,737
TOTAL	$6,265,070	37.77	$236,604,038

Exp. Lag Days	37.77	= (C)/(A)
Revenue Lag Days	42.12	
Adj. to Rate Base	74,742	
Rate Base Factor	10,963,538	
New Rate Base	$11,038,280	

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
SUMMARY OF EARNINGS
AT PRESENT RATES - Total System
(Thousands of 1992 Dollars)

Description	Edison Estimated	DRA Estimated	Adopted
Operating Revenues	(a)	(b)	(c)
Present Rate Revenues	$3,962,400	$4,033,984	$4,029,254
Operating Expenses			
Production	541,212	525,524	523,241
Transmission	81,369	80,169	77,417
Distribution	187,531	185,996	179,979
Customer Accounts	124,608	123,950	120,807
Uncollectibles	8,231	8,380	8,370
Customer Service & Information	157,209	136,248	153,467
Administrative & General	459,451	386,913	412,229
Franchise Requirements	31,212	31,776	31,738
Sales Tax Increase	1,927	1,927	1,822
Compensation Adjustment	0	(16,458)	0
Information Service Productivity	0	(11,211)	0
Cost Containment	0	(16,778)	0
Revenue Credits	(105,599)	(113,599)	(107,712)
Subtotal	$1,487,150	$1,322,839	$1,401,359
Depreciation (Excl. Nucl. Decomm.)	670,368	650,231	651,678
Nuclear Decommissioning Exp.	97,104	96,325	96,325
Taxes Other Than On Income	202,956	196,142	200,124
Taxes On Income	428,895	546,439	504,123
Total Operating Expenses	$2,886,473	$2,811,976	$2,853,608
Net Operating Income	$1,075,927	$1,222,008	$1,175,646
DSM Incentive	0	0	0
Total Net Operating Revenues	$1,075,927	$1,222,008	$1,175,646
Rate Base	$11,198,043	$10,888,415	$11,038,280
Rate of Return	9.61%	11.22%	10.65%

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
SUMMARY OF EARNINGS
AT PRESENT RATES - CPUC Jurisdiction
(Thousands of 1992 Dollars)

Description	Edison Estimated	DRA Estimated	Adopted
	(a)	(b)	(c)
Operating Revenues			
Present Rate Revenues	$3,957,387	$4,028,969	$4,024,239
Operating Expenses			
Production	539,659	524,041	521,763
Transmission	81,278	80,081	77,332
Distribution	187,411	185,876	179,863
Customer Accounts	124,586	123,928	120,785
Uncollectibles	8,231	8,380	8,370
Customer Service & Information	157,209	136,248	153,467
Administrative & General	458,766	386,349	411,625
Franchise Requirements	31,172	31,736	31,699
Sales Tax Increase	1,927	1,927	1,820
Compensation Adjustment	0	(16,434)	0
Information Service Productivity	0	(11,193)	[illegible]
Cost Containment	0	(16,752)	0
Revenue Credits	(105,517)	(113,510)	(107,628)
Subtotal	$1,484,722	$1,320,677	$1,399,096
Depreciation (Excl. Nucl. Decomm.)	669,546	649,449	650,894
Nuclear Decommissioning Exp.	96,986	96,209	96,209
Taxes Other Than On Income	202,671	195,872	199,849
Taxes On Income	428,643	546,039	503,819
Total Operating Expenses	$2,882,568	$2,808,247	$2,849,867
Net Operating Income	$1,074,819	$1,220,722	$1,174,372
DSM Incentive	0	0	0
Total Net Operating Revenues	$1,074,819	$1,220,722	$1,174,372
Rate Base	$11,183,184	$10,874,206	$11,023,895
Rate of Return	9.61%	11.23%	10.65%

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
SUMMARY OF EARNINGS
AT ADOPTED RATES - Total System
(Thousands of 1992 Dollars)

Description	Edison Estimated	DRA Estimated	Adopted
Operating Revenues	(a)	(b)	(c)
Present Rate Revenues	$3,962,400	$4,033,984	$4,029,254
Change in Revenues	217,202	(130,113)	(11,845)
Total Operating Revenues	$4,179,602	$3,903,871	$4,017,409
Operating Expenses			
Production	541,212	525,524	523,241
Transmission	81,369	80,169	77,417
Distribution	187,531	185,996	179,979
Customer Accounts	124,608	123,950	120,807
Uncollectibles	8,681	8,109	8,356
Customer Service & Information	157,209	136,248	153,467
Administrative & General	459,451	386,913	412,229
Franchise Requirements	32,923	30,751	31,645
Compensation Adjustment	1,927	1,927	1,822
Information Service Productivity	0	(16,458)	0
Cost Containment	0	(11,211)	0
Sales Tax Increase	0	(16,778)	0
Revenue Credits	(105,599)	(113,599)	(107,712)
Subtotal	$1,489,311	$1,321,542	$1,401,252
Depreciation (Excl. Nucl. Decomm.)	670,368	650,231	651,678
Nuclear Decommissioning Exp.	97,104	96,325	96,325
Taxes Other Than On Income	202,956	196,142	200,110
Taxes On Income	521,317	490,836	499,103
Total Operating Expenses	$2,981,056	$2,755,076	$2,848,467
Net Operating Income	$1,198,546	$1,148,795	$1,168,942
DSM Incentive	(786)	0	0
Total Net Operating Revenues	$1,197,760	$1,148,795	$1,168,942
Rate Base	11,183,974	10,909,798	$11,038,280
Rate of Return	10.71%	10.53%	10.59% 1/

1/ As authorized in Edison's Cost of Capital application (A.91-05-024).

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
SUMMARY OF EARNINGS
AT ADOPTED RATES - CPUC Jurisdiction
(Thousands of 1992 Dollars)

Description	Edison Estimated	DRA Estimated	Adopted
	(a)	(b)	(c)
Operating Revenues			
Present Rate Revenues	$3,957,387	$4,028,969	$4,024,239
Change in Revenues	216,357	(130,494)	(12,287)
Total Operating Revenues (ALBRR)	$4,173,744	$3,898,475	$4,011,952
Operating Expenses			
Production	539,659	524,041	521,763
Transmission	81,278	80,081	77,332
Distribution	187,411	185,876	179,863
Customer Accounts	124,586	123,928	120,785
Uncollectibles	8,681	8,109	8,345
Customer Service & Information	157,209	136,248	153,467
Administrative & General	458,766	386,349	411,62[illegible]
Franchise Requirements	32,877	30,708	31,6[illegible]
Sales Tax Increase	1,924	1,924	1,820
Compensation Adjustment	0	(16,434)	0
Information Service Productivity	0	(11,193)	0
Cost Containment	0	(16,752)	0
Revenue Credits	(105,517)	(113,510)	(107,628)
Subtotal	$1,486,874	$1,319,375	$1,398,974
Depreciation (Excl. Nucl. Decomm.)	669,546	649,449	650,894
Nuclear Decommissioning Exp.	96,986	96,209	96,209
Taxes Other Than On Income	202,671	195,872	199,834
Taxes On Income	520,687	490,281	498,610
Total Operating Expenses	$2,976,764	$2,751,186	$2,844,521
Net Operating Income	$1,196,980	$1,147,289	$1,167,431
DSM Incentive	(786)	0	0
Total Net Operating Revenues	$1,196,194	$1,147,289	$1,167,431
Rate Base	$11,169,096	$10,895,518	$11,023,895
Rate of Return	10.71%	10.53%	10.59% 1/

1/ As authorized in Edison's Cost of Capital application (A.91-05-024).

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
SUMMARY OF NUCLEAR O&M EXPENSE - Edison's Share
(Thousands of 1992 Dollars)

Description	Adopted			
	Unit 1	Unit 2	Unit 3	Total
1. SONGS:				
Base	$55,972	$58,964	$49,641	$164,577
Refueling	15,657	0	15,657	31,314
NRC Fees	3,251	3,050	3,050	9,351
Subtotal	$74,880	$62,014	$68,348	$205,242
No. of Refueling Outages	1	0	1	2
Average Cost/Outage				$15,657
2. Palo Verde: 1/				
Base	$13,042	$13,739	$11,566	$38,346
Refueling	3,648	1,824	1,824	7,296
NRC Fees	642	642	642	1,927
Subtotal	$17,332	$16,205	$14,033	$47,569
No. of Refueling Outages	1	1/2	1/2	2
Average Cost/Outage				$3,648
Scaling Index	0.233	0.233	0.233	
Total Nuclear O&M Expenses				$252,811

1/ Palo Verde base and refueling O&M expenses are derived from SONGS O&M multiplied by a scaling index. The scaling index is derived from the adopted scaling factor of 1.131 and Edison's share of SONGS and Palo Verde (1.131*0.158/0.767).

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

CPUC JURISDICTIONAL FACTORS

Description	Edison Estimate	DRA Estimate	Adopted
Operating Expenses			
Production	99.713%	99.718%	99.717%
Transmission	99.889%	99.891%	99.891%
Distribution	99.936%	99.935%	99.935%
Customer Accounts	99.982%	99.982%	99.982%
Cust. Serv. & Inform.	100.000%	100.000%	100.000%
Administrative & General	99.851%	99.854%	99.854%
Sales Tax Increase			99.843%
Compensation Adjustment			
Cost Containment			
Revenue Credits	99.922%	99.922%	99.922%
Depreciation	99.878%	99.880%	99.880%
Taxes Other Than On Income	99.860%	99.862%	99.862
Taxes On Income	99.862%	99.862%	99.86
Rate Base	99.867%	99.870%	99.870%

APPENDIX D

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
DEVELOPMENT OF NET-TO-GROSS MULTIPLIER

Description	Rate	Amount Applied	Total
	(A)	(B)	(C=A*B)
Gross Operating Revenues			100.0000
Less: Uncollectible	0.2080%	100.0000	0.2080
Subtotal			99.7920
Less: Franchise Fees	0.7877%	100.0000	0.7877
Subtotal			99.0043
Less: Arizona & New Maxico Income Tax	0.1997%	99.0043	0.1977
Subtotal			98.8066
Less: Superfund Tax	0.12%	98.8066	0.1186
Subtotal			98.6880
Less: S.I.T.	8.7251%	99.0043	8.6382
Subtotal			90.0498
Less: F.I.T.	34.00%	98.6880	33.5539
Net Operating Revenues			56.4959
Uncoll. & F.F. Factor			1.0101
State & Fed. Tax Factor			1.6473
N-T-G Multiplier			1.7700

(END OF APPENDIX D)

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ATTRITION REVENUE REQUIREMENT ESTIMATES

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APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ATTRITION REVENUE REQUIREMENT ESTIMATES
- CPUC Jurisdiction
(Thousands of Nominal Dollars)

Description	GRC Adopted 1992	Incremt. Attrition 1993	Attrition 1993	Incremt. Attrition 1994	Attrition 1994
Operating Revenues	$4,011,952	$103,863	$4,115,815	$123,043	$4,238,858
Operating Expenses					
Production	521,763	496	522,259	34,991	557,250
Transmission	77,332	2,269	79,601	2,544	82,145
Distribution	179,863	5,943	185,805	6,640	192,445
Customer Accounts	120,785	3,506	124,291	3,969	128,260
Uncollectibles	8,345	216	8,561	256	8,817
Cust. Serv. & Inform.	153,467	3,328	156,795	3,606	160,401
Administrative & Gen.	411,625	8,164	419,789	9,060	428,850
Franchise Requirements	31,602	818	32,420	969	33,389
Sales Tax Increase	1,820	29	1,849	76	1,924
Compensation Adjustment	0	0	0	0	0
Cost Containment	0	0	0	0	0
Revenue Credits	(107,628)	0	(107,628)	0	(107,628)
Subtotal	$1,398,974	$24,769	$1,423,743	$62,111	$1,485,854
Depreciation (Excl. Nucl. Decomm.)	650,894	39,042	689,936	29,339	719,275
Nuclear Decomm. Exp.	96,209	(1,254)	94,955	0	94,955
Taxes Other Than On Income	199,834	2,419	202,253	1,508	203,761
Taxes On Income	498,610	28,947	527,557	15,834	543,391
Total Operating Expenses	$2,844,521	$93,923	$2,938,444	$108,792	$3,047,236
Net Operating Income	$1,167,431	9,940	$1,177,371	14,251	$1,191,622
DSM Incentive	0	0	0	0	0
Total Net Oper. Rev.	$1,167,431	$9,940	$1,177,371	$14,251	$1,191,622
Rate Base	11,023,895	93,865	$11,117,760	134,570	$11,252,329
Rate of Return	10.59%		10.59%		10.59%

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

SUMMARY OF ATTRITION INCREMENTAL REVENUE REQUIREMENTS
- CPUC Jurisdiction
(Thousands of Nominal Dollars)

Description	Incremt. Attrition 1993	Incremt. Attrition 1994
Operating Expenses		
O&M Expenses		
Labor	$20,352	$23,572
Nonlabor & Other	19,483	20,553
SONGS Refueling	(16,129)	16,685
Sales Tax Increase	29	76
Revenue Credits	0	0
Subtotal	$23,735	$60,886
Franchise Fees and Uncoll.	$239	$612
Total Expenses	$23,974	$61,498
Capital Related 1/		
Depreciation (Excl. Nucl. Decomm.)	$69,106	$51,931
Nuclear Decomm. Exp.	(2,220)	0
Ad Valorem Tax	2,444	1,523
Income Taxes	(3,960)	(12,726)
Rate Base	14,520	20,816
Total Cap. Related	$79,889	$61,544
Total Attrition Incremental Rev. Reqt.	$103,863	$123,043

1/ Incl. Franchise Fees, Uncollectibles and Income Taxes.

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ESCALATION RATES FOR ATTRITION YEARS 1/
(Base Year 1992)

	Labor		Nonlabor	
Year	Rate	Index	Rate	Index
1992	-	100.00		100.00
1993	3.30%	103.30	3.31%	103.31
1994	3.70%	107.12	3.38%	106.80

1/ Estimates from Exhibit 174. Actual escalation rates for Attrition Year 1993 & 1994 should be updated in Edison's Attrition filings.

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

CPUC JURISDICTIONAL FACTORS FOR ATTRITION YEARS

Description	Attrition 1993 &1994 1/
Operating Expenses	
Production	99.717%
Transmission	99.891%
Distribution	99.935%
Customer Accounts	99.982%
Cust. Serv. & Inform.	100.000%
Administrative & General	99.854%
Sales Tax Increase	-
Compensation Adjustment	-
Cost Containment	-
Revenue Credits	99.922%
Depreciation	99.880%
Taxes Other Than On Income	99.862%
Taxes On Income	99.862%
State	99.862%
Federal	99.862%
Rate Base	99.870%

1/ Test Year values from Appendix D, Page 32. Edison may revise the CPUC jurisdictional factors in its attrition filings as authorized in D. 85-12-076.

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ATTRITION INCREMENTAL O&M EXPENSES
- CPUC Jurisdiction
(Thousands of Nominal Dollars)

Description	GRC Adopted 1992	CPUC Jurf. 1992	Incremt. Attrition 1993	Incremt. Attrition 1994
Operating Expenses				
PRODUCTION		99.717%		
Labor	$225,732	$225,095	$7,428	$8,603
Nonlabor	278,650	277,862	9,197	9,703
Other	18,859	18,806	0	0
Total	$523,241	$521,763	$16,625	$18,306
Number of Refueling Outages (SONGS)	2		1	2
Refueling Outage for SONGS				
Labor	3,291	3,282	108	234
Nonlabor	12,366	12,331	408	839
Total	$15,657	$15,613	$516	$1,072
Total Production Adjustment			(3,390)	3,515
Labor			(12,739)	13,170
Nonlabor			($16,129)	$16,685
Total				
TOTAL PRODUCTION				
Labor			4,038	12,119
Nonlabor			(3,542)	22,872
Other			0	0
Total			$496	$34,991
TRANSMISSION		99.891%		
Labor	44,256	44,208	1,459	1,690
Nonlabor	24,498	24,471	810	855
Other	8,663	8,654	0	0
Total	$77,417	$77,332	$2,269	$2,544
DISTRIBUTION		99.935%		
Labor	108,843	108,772	3,589	4,157
Nonlabor	71,137	71,091	2,353	2,482
Other	0	0	0	0
Total	$179,979	$179,863	$5,943	$6,640
CUSTOMER ACCOUNTS		99.982%		
Labor	79,376	79,362	2,619	3,033
Nonlabor	26,798	26,793	887	936
Other (Less Uncoll.)	14,633	14,630	0	0
Total	$120,807	$120,785	$3,506	$3,969
CUSTOMER SERV. & INFORM.		100.000%		
Labor	27,869	27,869	920	1,065
Nonlabor	72,769	72,769	2,409	2,541
Other	52,829	52,829	0	0
Total	$153,467	$153,467	$3,328	$3,606
(Incl. DSM Amort. Depr.)	$12,606		$0	$0
ADMINISTRATIVE & GENERAL		99.854%		
Labor	131,617	131,424	4,337	5,023
Nonlabor	115,788	115,619	3,827	4,037
Other (Less FF)	164,824	164,583	0	0
Total	$412,229	$411,625	$8,164	$9,060
(Incl. Health Care & RD&D)				
Labor	11,627	11,609	383	444
Nonlabor	51,417	51,342	1,699	1,793
Other	71,613	71,508	0	0
Total	$134,656	$134,459	$2,083	$2,237

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ATTRITION INCREMENTAL O&M EXPENSES (Cont.)
- CPUC Jurisdiction
(Thousands of Nominal Dollars)

Description	GRC Adopted 1992	CPUC Juri. 1992	Incremt. Attrition 1993	Incremt. Attrition 1994
Operating Expenses				
(Unadjusted)				
Total Labor	617,692	616,729	20,352	23,572
Total Nonlabor	589,640	588,605	19,483	20,553
Total Other	259,808	259,501	0	0
Total Opr. Exp.	$1,467,140	$1,464,835	$39,835	$44,125
SONGS Refueling				
Labor			(3,390)	3,515
Nonlabor			(12,739)	13,170
Total			($16,129)	$16,685

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ATTRITION INCREMENTAL CAPITAL RELATED
REVENUE REQUIREMENTS - TAXES OTHER THAN ON INCOME
(Thousands of Nominal Dollars)

Description	GRC Adopted 1992	Incremt. Attrition 1993	Incremt. Attrition 1994
TAXES OTHER THAN ON INCOME	(12/91)	(12/92)	(12/93)
Ad Valorem Taxes:			
Plant In Service	$17,976,888	$680,902	$730,621
Depreciation Resv.	(5,773,616)	(588,743)	(557,507)
Net Change in HOLD Unitary Property	12,203,272	92,159	173,114
Assessed Value of Unitary Property-% of Hold	105.412%		
Assessed Value of Unitary Property		97,147	182,483
Tax Rate	1.080%	1,049	1,971
50% of :			
Previous Year		1,898	525
Current Year		525	985
Total Incr./(Decr.) in Ad Valorem Taxes		$2,423	$1,510
CPUC Jurisdiction	99.862%	$2,419	$1,508
Franchise Fees & Uncollectibles	0.9957%	24	15
Total Incr./(Decr.) in Rev. Reqt.		$2,444	$1,523

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ATTRITION INCREMENTAL CAPITAL RELATED
REVENUE REQUIREMENTS - TAXES ON INCOME
(Thousands of Nominal Dollars)

Description	GRC Adopted 1992	Incremt. Attrition 1993	Incremt. Attrition 1994
TAXES ON INCOME			
State Tax Depreciation:		$22,946	$15,237
Incr./(Decr.) in SIT (CA, AZ, & NM)	8.9248%	(2,048)	(1,360)
Incr./(Decr.) in FIT	34%	696	462
Total Incr./(Decr.) in Income Taxes		(1,352)	(898)
Net-To-Gross Multiplier	1.7700		
Incr./(Decr.) in Rev. Reqt.		(2,392)	(1,589)
CPUC Jurisdiction Factor	99.862%		
Total Incr./(Decr.) in Rev. Reqt.		($2,389)	($1,586)
Federal Tax Depreciation:		($62,959)	$5,513
Incr./(Decr.) in FIT	34%	21,406	(1,874)
Net-To-Gross Multiplier	1.7700		
Incr./(Decr.) in Rev. Reqt.		37,890	(3,318)
CPUC Jurisdiction Factor	99.862%		
Total Incr./(Decr.) in Rev. Reqt.		$37,837	($3,313)
Income Tax Deferred:		(22,442)	(4,438)
Net-To-Gross Multiplier	1.7700		
Incr./(Decr.) in Rev. Reqt.		(39,723)	(7,856)
CPUC Jurisdiction	99.862%		
Total Incr./(Decr.) in Rev. Reqt.		($39,668)	($7,845)
Investment Tax Credit - Deferred:		$214	$57
Net-To-Gross Multiplier	1.7700		
Incr./(Decr.) in Rev. Reqt.		379	101
CPUC Jurisdiction Factor	99.862%		
Total Incr./(Decr.) in Rev. Reqt.		$378	$101
Avg. Accumd. Deferred ITC As A Reduction To Rate Base For CCFT Interest Ded.:		($26,295)	($18,286)
Weighted Cost for Long Term Debt	4.31%		
Incr./(Decr.) in CCFT Interest		1,133	788
Incr./(Decr.) in SIT (CA, AZ, & NM)	8.9248%	(101)	(70)
Incr./(Decr.) in FIT	34%	34	24
Total Incr./(Decr.) in Income Taxes		(67)	(46)
Net-To-Gross Multiplier	1.7700		
Incr./(Decr.) in Rev. Reqt.		(118)	(82)
CPUC Jurisdiction Factor	99.862%		
Total Incr./(Decr.) in Rev. Reqt.		($118)	($82)
Total Incr./(Decr.) in Rev. Reqt. - CPUC Jurisdiction		($3,960)	($12,726)

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ATTRITION: INCREMENTAL CAPITAL RELATED
REVENUE REQUIREMENTS - DEPRECIATION EXPENSE
(Thousands of Nominal Dollars)

Description	GRC Adopted 1992	Incremt. Attrition 1993	Incremt. Attrition 1994
DEPRECIATION EXPENSE			
Depreciation Expense:		$39,089	$29,374
CPUC Jurisdiction	99.880%	39,042	29,339
Net-To-Gross Multiplier	1.7700		
Total Incr./(Decr.) in Rev. Reqt.		$69,106	$51,931
Decommissioning Expense:		(1,256)	0
CPUC Jurisdiction	100.000%	(1,254)	0
Net-To-Gross Multiplier	1.7700		
Total Incr./(Decr.) in Rev. Reqt.		($2,220)	$0
Total Incr./(Decr.) in Rev. Reqt. - CPUC Jurisdiction		$66,885	$51,931

APPENDIX E

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992

ATTRITION INCREMENTAL CAPITAL RELATED
REVENUE REQUIREMENTS - RATE BASE
(Thousands of Nominal Dollars)

Description	GRC Adopted 1992	Incremt. Attrition 1993	Incremt. Attrition 1994
PLANT IN SERVICE - WTD. AVG.	$18,301,925	$718,601	$766,155
Rate of Return	10.59%	76,100	81,136
Net-To-Gross Multiplier	1.4607		
Incr./(Decr.) in Rev. Reqt.		111,159	118,515
CPUC Jurisdiction Factor	99.870%		
Total Incr./(Decr.) in Rev. Reqt.		$111,014	$118,361
DEFERRED DEBIT ACCOUNTS	$69,602	$3,783	$958
Rate of Return	10.59%	401	101
Net-To-Gross Multiplier	1.4607		
Incr./(Decr.) in Rev. Reqt.		585	148
CPUC Jurisdiction Factor	99.870%		
Total Incr./(Decr.) in Rev. Reqt.		$584	$148
DEPRECIATION RESERVE		($545,992)	($568,444)
Rate of Return	10.59%	(57,821)	(60,198)
Net-To-Gross Multiplier	1.4607		
Incr./(Decr.) in Rev. Reqt.		(84,459)	(87,932)
CPUC Jurisdiction Factor	99.870%		
Total Incr./(Decr.) in Rev. Reqt.		($84,348)	($87,817)
DEFERRED TAXES - ACRS		($82,405)	($63,924)
Rate of Return	10.59%	(8,727)	(6,770)
Net-To-Gross Multiplier	1.4607		
Incr./(Decr.) in Rev. Reqt.		(12,747)	(9,888)
CPUC Jurisdiction Factor	99.870%		
Total Incr./(Decr.) in Rev. Reqt.		($12,730)	($9,875)
Total Incr./(Decr.) In Rev. Reqt.		$14,520	$20,816
Total Incr./(Decr.) In Rate Base - Wtd. Avg.		$93,987	$134,745
CPUC Jurisdiction	99.870%	$93,865	$134,570

(END OF APPENDIX E)

APPENDIX F

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
ADOPTED MARGINAL COSTS

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APPENDIX F

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
ADOPTED MARGINAL CAPACITY COSTS

Line No.	Description		Cost per kW ($/kW)	Comments
	GENERATION:			
1.	Combustion Turbine (CT) Capital Cost		549.31	Exhibit 113, Joint Testimony on Marginal Costs.
2.	General Plant Loading		33.05	(Line 1) x General Plant Loading of 6.02%
3.	Working Capital		6.35	(Line 1 + Line 2) x Working Capital Factor of 1.09%
4.	Total CT Investment:	588.71		Subtotal (Line 1 + Line 2 + Line 3)
5.	Interconnection Plant (IP) Capital Cost		33.89	Exh. 113
6.	General Plant Loading		2.04	(Line 5) x General Plant Loading of 6.02%
7.	Working Capital		0.39	(Line 5 + Line 6) x Working Capital Factor of 1.09%
8.	Total IP Investment:	36.32		Subtotal (Line 5 + Line 6 + Line 7)
9.	Annual Combustion Turbine Cost ($/kW/yr)		60.34	(Line 4) x Annual Cost Factor of 10.25%
10.	Annual Interconnection Plant Cost ($/kW/yr)		3.74	(Line 8) x Annual Cost Factor of 10.31%
11.	Annual Carrying Cost of Fuel Inventory ($/kW/yr)		1.12	Exh. 113
12.	Annual Demand-Related O&M Expense ($/kW/yr)		16.95	Exh. 113, corrected from $16.89
13.	Annual Marginal Generation Cost ($/kW/yr):		82.15	(Line 9 + Line 10 + Line 11 + Line 12)
	TRANSMISSION:			
14.	Transmission Investment per kW Change in Load		241.55	Exh. 113
15.	General Plant Loading		14.53	(Line 14) x General Plant Loading of 6.02%
16.	Working Capital		2.79	(Line 14 + Line 15) x Working Capital Factor of 1.09%
17.	Total Investment:	258.88		Subtotal (Line 14 + Line 15 + Line 16)
18.	Annual Cost ($/kW/yr)		28.50	(Line 17) x Annual Cost Factor of 11.01%
19.	Annual Demand-Related O&M Expense ($/kW/yr)		4.80	Exh. 113, updated to reflect adopted Transmission O&M expenses
20.	Annual Marginal Transmission Cost ($/kW/yr):		33.30	(Line 18 + Line 19)
	DISTRIBUTION:			
21.	Distribution Investment per kW Change in Load		364.86	Exh. 113
22.	General Plant Loading		21.95	(Line 21) x General Plant Loading of 6.02%
23.	Working Capital		4.22	(Line 21 + Line 22) x Working Capital Factor of 1.09%
24.	Total Investment:	391.03		Subtotal (Line 21 + Line 22 + Line 23)
25.	Annual Cost ($/kW/yr)		40.75	(Line 24) x Annual Cost Factor of 10.42%
26.	Annual Demand-Related O&M Expense ($/kW/yr)		12.93	Exh. 113, updated to reflect adopted Distribution O&M expenses
27.	Annual Marginal Distribution Cost ($/kW/yr):		53.68	(Line 25 + Line 26)

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
ADOPTED MARGINAL CUSTOMER COSTS

Line No.	Cost Component			Marginal Customer Cost [a] ($/Customer/Yr)
	SUMMARY:			
1.	Domestic			62.41
2.	General Service - Small			126.69 [b]
3.	General Service - Large			922.42
4.	Agriculture and Pumping			536.28
5.	Time-of-Use - Secondary			3,217.09
6.	Time-of-Use - Primary			2,986.87
7.	Time-of-Use - Subtransmission			3,036.89
8.	DOMESTIC:	Single	Overhead	64.99
9.			Underground	66.49
10.		Multiple		56.77
11.	Domestic Average			62.41
12.	LSMP:	GS-1	Single Phase	123.10
13.			Three Phase	139.33
14.			Average GS-1	127.81
15.		TC-1		64.99
16.		GS-1 Group Average		126.69
17.		GS-2	Secondary	923.34
18.			Primary	602.10
19.			Average GS-2	922.39
20.		TOU-GS	Secondary	955.44
21.			Primary	634.19
22.			Average TOU-GS	940.22
23.		GS-2 Group Average		922.42
24.	AGRICULTURE:	PA-1		462.90
25.		PA-2	Secondary	967.30
26.			Primary	606.02
27.			Average PA-2	964.21
28.		TOU-PA	Secondary	999.72
29.			Primary	638.44
30.			Average POU-PA	998.42
31.		PA-2 Group Average		986.83
32.	Agriculture Average			536.28
33.	INDUSTRIAL:	TOU-8	Secondary	3,217.09
34.			Primary	2,986.87
35.			Subtransmission	3,036.89

[a] Exhibit 113, Joint Exhibit on Marginal Costs, updated to reflect adopted results of operations.

[b] Exhibit 113 references Average GS-1 for General Service - Small value, while this table references GS-1 Group Average, which includes TC-1.

APPENDIX F

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
ADOPTED MARGINAL ENERGY COSTS

Line No.	Description	SUMMER On-Peak	SUMMER Mid-Peak	SUMMER Off-Peak	WINTER Mid-Peak	WINTER Off-Peak
1.	Incremental Energy Rate (Btu/kWh)	14,199	8,784	7,159	10,516	8,431
2.	Fuel Price ($/MMBtu)	3.35	3.35	3.35	3.35	3.35
3.	Marginal Fuel Cost ($/kWh)	0.048	0.029	0.024	0.035	0.028
4.	Variable O&M ($/kWh)	0.003	0.003	0.003	0.003	0.003
5.	Generation-Level Marginal Energy Cost ($/kWh)	0.051	0.032	0.027	0.038	0.031

Line 1. Exhibit 113, Joint Testimony on Marginal Costs.
Line 2. Fuel price to be adopted in ECAC proceedings adopted for this GRC cycle; $3.35 per MMBtu is used here for illustrative purpose only.
Line 3. (Line 1 x Line 2) / 1,000,000
Line 4. Exhibit 113. Adopted for this GRC cycle.
Line 5. (Line 3 + Line 4)

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
ADOPTED MARGINAL CUSTOMER COSTS FOR STREET LIGHTS

Line No.	Description	Marginal Customer Cost for Street Light [a] $/Meter/Year	$/Lamp/Year
1.	LS-3 Primary (Series)	591.52	---
2.	LS-3 Secondary (Multiple)	93.18	---
3.	LS-1	---	3.64
4.	LS-2 Primary (Series)	---	5.14
5.	LS-2 Secondary (Multiple)	---	8.87
6.	OL-1	---	3.64
7.	DWL-A	---	3.64
8.	DWL-B	---	3.64
9.	DWL-C	---	0.00 [b]

[a] Exhibit 117, Joint Exhibit on Marginal Street Light Costs, updated to reflect adopted results of operations.

[b] Cost shown as zero because this schedule is no longer offered to new customers.

SOUTHERN CALIFORNIA EDISON COMPANY
Test Year 1992
ADOPTED MARGINAL STREET LIGHT COSTS
FOR HIGH PRESSURE SODIUM VAPOR (HPSV)

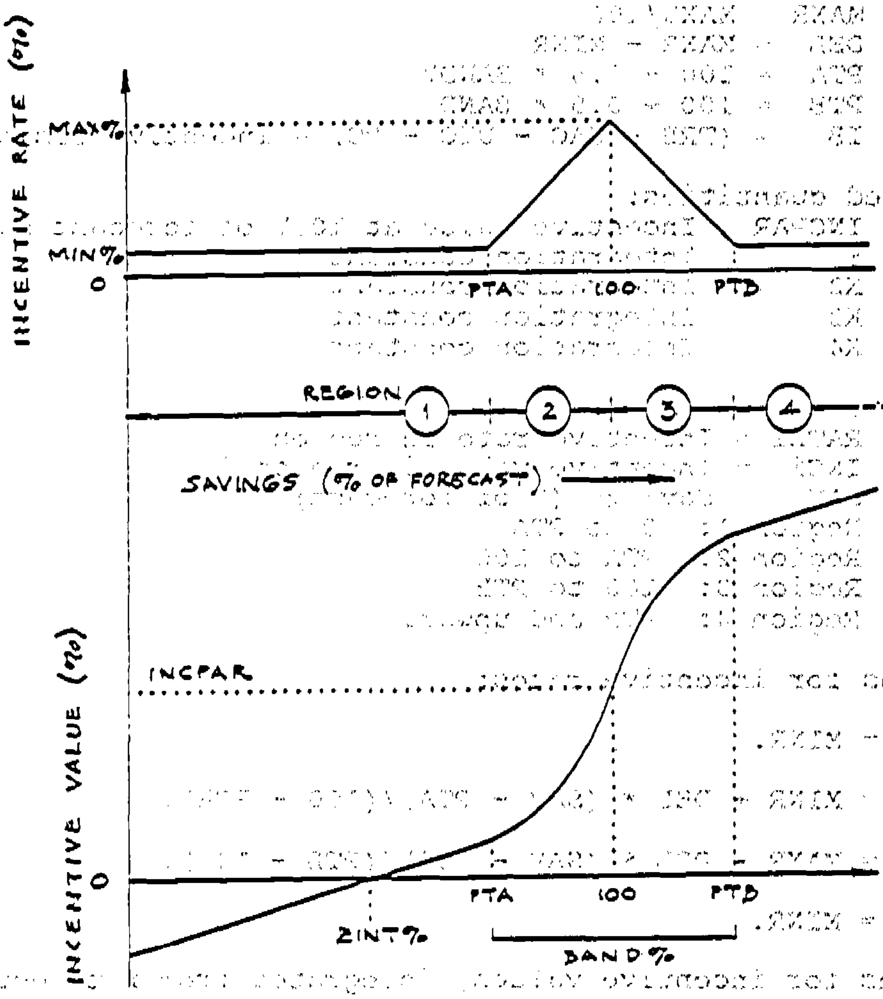
Line No.	Description	Marginal Street Light Costs for HPSV [a]						
		Luminaire Size (Lumens)						
		4000	5800	9500	1600	22000	27500	50000
1.	O&M COSTS:							
2.	Customer-Owned --							
3.	--Unmetered service, $/Lamp/Month:							
4.	Other repair cost -							
5.	at Secondary	0.08	0.08	0.08	0.08	0.08	0.08	0.08
6.	at Primary	0.15	0.15	0.15	0.15	0.15	0.15	0.15
7.	Lamp replacement	0.35	0.35	0.35	0.35	0.35	0.35	0.35
8.	--Metered service, $/Meter/Month:							
9.	Other repair cost -							
10.	at Secondary	0.14	0.14	0.14	0.14	0.14	0.14	0.14
12.	at Primary	5.46	5.46	5.46	5.46	5.46	5.46	5.46
13.	Lamp replacement	0.35	0.35	0.35	0.35	0.35	0.35	0.35
14.	Edison-Owned, $/Lamp/Month:							
15.	Lamp replacement	0.35	0.35	0.35	0.35	0.35	0.35	0.35
16.	Night Patrol & Other Repair	0.39	0.39	0.39	0.39	0.39	0.39	0.39
17.	INVESTMENT COSTS:							
18.	Customer-Owned --							
19.	--Unmetered service, $/Lamp/Month:							
20.	at Secondary	0.52	0.52	0.52	0.52	0.52	0.52	0.52
21.	at Primary	3.26	3.26	3.26	3.26	3.26	3.26	3.26
22.	--Metered service, $/Meter/Month:							
23.	at Secondary	74.87	74.87	74.87	74.87	74.87	74.87	74.87
24.	at Primary	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25.	Edison-Onwed, $/Lamp/Month:							
26.	at Secondary	3.94	3.96	4.26	4.25	4.58	4.58	4.72

[a] Exhibit 117, Joint Exhibit on Marginal Street Light Costs, updated to reflect adopted results of operations.

(END OF APPENDIX F)

APPENDIX G
Page 1

DERIVATION OF INCENTIVE PAYMENT FORMULA



Inputs:

MIN%	Minimum incentive rate (%)
MAX%	Maximum incentive rate (%)
BAND%	Bandwidth of variable rate (%)
ZINT%	Zero intercept for incentive (%)
TRB	Total resource benefits ($ million)
UAC	Utility administrative cost ($ million)
UIC	Utility incentive cost ($ million)
PC	Participant cost ($ million)

Internal variables:

MINR = MIN%/100
MAXR = MAX%/100
DEL = MAXR - MINR
PTA = 100 - 0.5 * BAND%
PTB = 100 + 0.5 * BAND%
IB = (TRB - UAC - UIC - PC) = incentive basis

Calculated quantities:

INCPAR	Incentive value at 100% of forecast savings (%)
K1	Integration constant
K2	Integration constant
K3	Integration constant
K4	Integration constant

Nomenclature:

RATEi = Incentive rate in region i
INCi = Incentive value in region i
SAV = Savings (% of forecast)
Region 1: 0 to PTA
Region 2: PTA to 100
Region 3: 100 to PTB
Region 4: PTB and upward

Equations for incentive rates:

RATE1 = MINR. (1)

RATE2 = MINR + DEL * (SAV - PTA)/(100 - PTA). (2)

RATE3 = MAXR - DEL * (SAV - 100)/(PTB - 100). (3)

RATE4 = MINR. (4)

Equations for incentive values, integrated from rate equations:

INC1 = $\int$RATE1, such that INC1(ZINT%) = 0. (5)

INC1 = $\int$MINR = K1 + MINR * SAV, (6)

and K1 = - MINR * ZINT%. (7)

INC2 = $\int$RATE2, such that INC2(PTA) = INC1(PTA). (8)

INC2 = $\int$[MINR + DEL * (SAV - PTA)/(100 - PTA)]. (9)

APPENDIX G

$$INC2 = K2 + (MIN - DEL * PTA/(100 - PTA)) * SAV + 0.5 * DEL/(100 - PTA) * SAV * SAV, \quad (10)$$

$$\text{and } K2 = K1 + 0.5 * DEL/(100 - PTA) * PTA * PTA. \quad (11)$$

$$INC3 = \int RATE3, \text{ such that } INC3(100) = INC2(100). \quad (12)$$

$$INC3 = \int [MAXR - DEL * (SAV - 100)/(PTB - 100)]. \quad (13)$$

$$INC3 = K3 + (MAXR + DEL * 100/(PTB - 100)) * SAV - 0.5 * DEL/(PTB) - 100) * SAV * SAV. \quad (14)$$

$$INCPAR = INC2(100), \text{ in units of } (\%). \quad (15)$$

$$INCPAR = K2 + (MINR - DEL * PTA/(100 - PTA)) * 100 + 0.5 * DEL/(100 - PTA) * 100 * 100, \quad (16)$$

$$\text{and } K3 = INCPAR - MAXR * 100 - 0.5 * DEL/(PTB - 100) * 100 * 100. \quad (17)$$

$$INC4 = \int RATE4, \text{ such that } INC4(PTB) = INC3(PTB). \quad (18)$$

$$INC4 = \int MINR = K4 + MINR * SAV, \quad (19)$$

$$\text{and } K4 = 2 * INCPAR - K1 - MINR * PTA - MINR * PTB. \quad (20)$$

Incentive ($ million) = IB * INCi in each of four regions. (21)

Adjust inputs (e.g., MAX%) until incentive at SAV = 100% matches the target incentive value.

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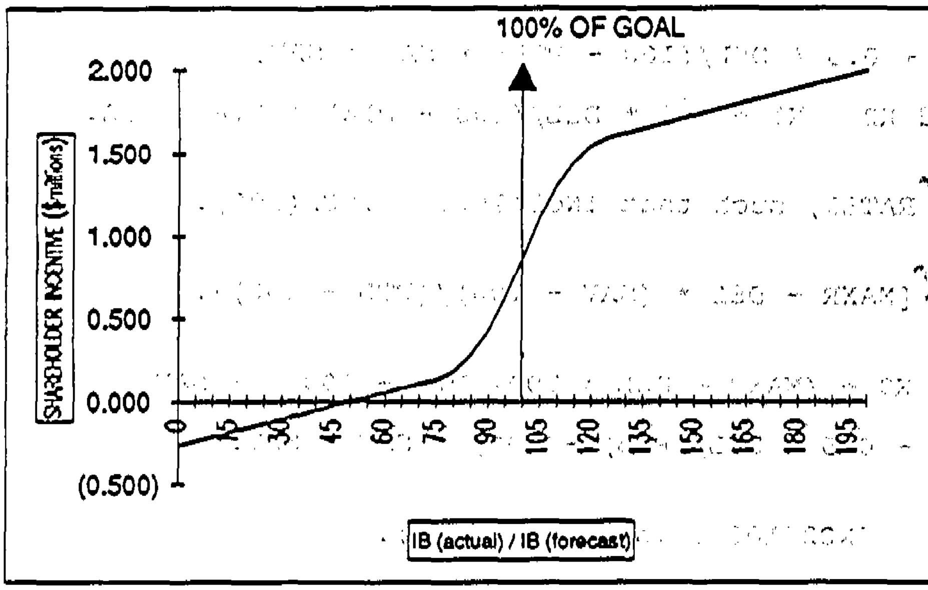
RESIDENTIAL APPLIANCE EFFICIENCY INCENTIVES



IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)
0	($0.27)	55	$0.03	110	$1.30	165	$1.81
5	($0.24)	60	$0.05	115	$1.44	170	$1.83
10	($0.21)	65	$0.08	120	$1.54	175	$1.86
15	($0.19)	70	$0.11	125	$1.59	180	$1.89
20	($0.16)	75	$0.13	130	$1.62	185	$1.91
25	($0.13)	80	$0.18	135	$1.65	190	$1.94
30	($0.11)	85	$0.28	140	$1.67	195	$1.97
35	($0.08)	90	$0.43	145	$1.70	200	$1.99
40	($0.05)	95	$0.62	150	$1.73		
45	($0.03)	100	$0.86	155	$1.75		
50	$0.00	105	$1.10	160	$1.78		

	(millions)
TOTAL RESOURCE BENEFIT (TRB)	$12.37
UTILITY ADMINISTRATION COST (UAC)	$3.88
UTILITY INCENTIVE COST (UIC)	$4.27
PARTICIPANT COST (PC)	$5.65
TARGET INCENTIVE	$0.86
TOTAL EFFECTIVE INCENTIVE %	24.45%

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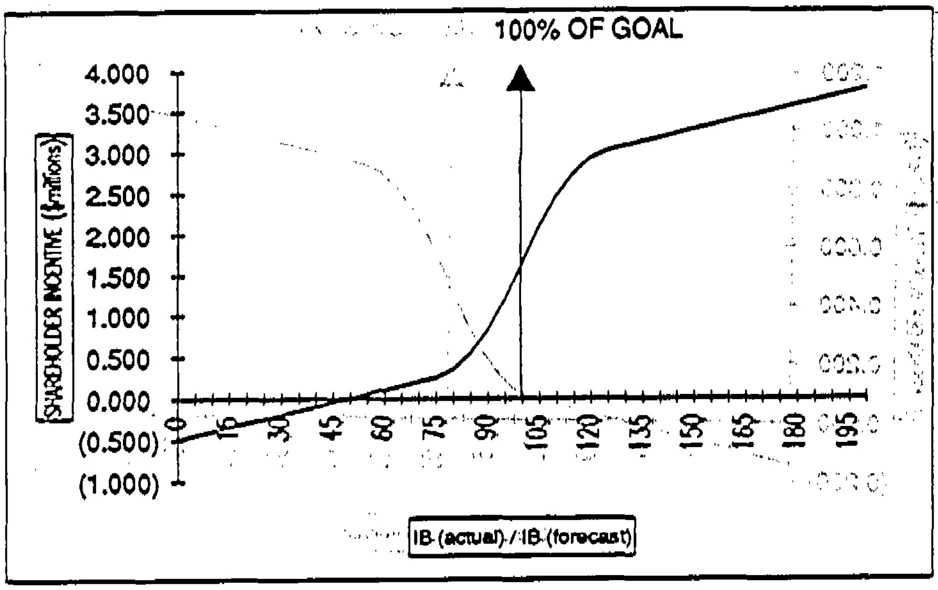
COMMERCIAL ENERGY EFFICIENCY INCENTIVES



IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)
0	($0.50)	55	$0.05	110	$2.46	165	$3.42
5	($0.45)	60	$0.10	115	$2.74	170	$3.47
10	($0.40)	65	$0.15	120	$2.92	175	$3.52
15	($0.35)	70	$0.20	125	$3.02	180	$3.57
20	($0.30)	75	$0.25	130	$3.07	185	$3.62
25	($0.25)	80	$0.35	135	$3.12	190	$3.67
30	($0.20)	85	$0.53	140	$3.17	195	$3.72
35	($0.15)	90	$0.81	145	$3.22	200	$3.77
40	($0.10)	95	$1.18	150	$3.27		
45	($0.05)	100	$1.63	155	$3.32		
50	$0.00	105	$2.09	160	$3.37		

	(millions)
TOTAL RESOURCE BENEFIT (TRB)	$169.79
UTILITY ADMINISTRATION COST (UAC)	$4.29
UTILITY INCENTIVE COST (UIC)	$11.14
PARTICIPANT COST (PC)	$21.97
TARGET INCENTIVE	$1.63
TOTAL EFFECTIVE INCENTIVE %	1.10%

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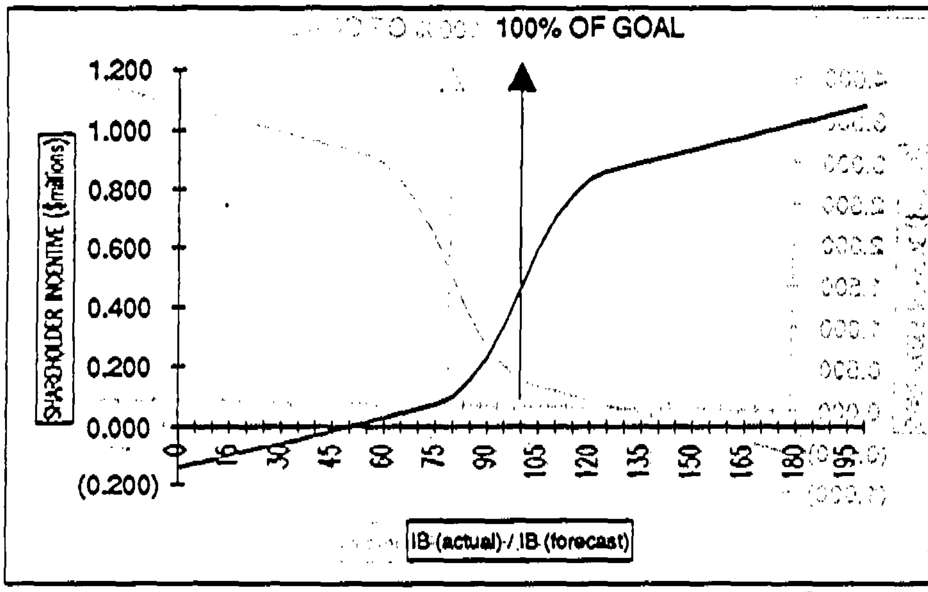
INDUSTRIAL ENERGY EFFICIENCY INCENTIVES



IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)
0	($0.14)	55	$0.01	110	$0.70	165	$0.98
5	($0.13)	60	$0.03	115	$0.78	170	$0.99
10	($0.11)	65	$0.04	120	$0.83	175	$1.01
15	($0.10)	70	$0.06	125	$0.86	180	$1.02
20	($0.09)	75	$0.07	130	$0.88	185	$1.03
25	($0.07)	80	$0.10	135	$0.89	190	$1.05
30	($0.06)	85	$0.15	140	$0.91	195	$1.06
35	($0.04)	90	$0.23	145	$0.92	200	$1.08
40	($0.03)	95	$0.34	150	$0.93		
45	($0.01)	100	$0.47	155	$0.95		
50	$0.00	105	$0.60	160	$0.96		

	(millions)
TOTAL RESOURCE BENEFIT (TRB)	$40.49
UTILITY ADMINISTRATION COST (UAC)	$1.20
UTILITY INCENTIVE COST (UIC)	$3.21
PARTICIPANT COST (PC)	$6.21
TARGET INCENTIVE	$0.47
TOTAL EFFECTIVE INCENTIVE %	1.35%

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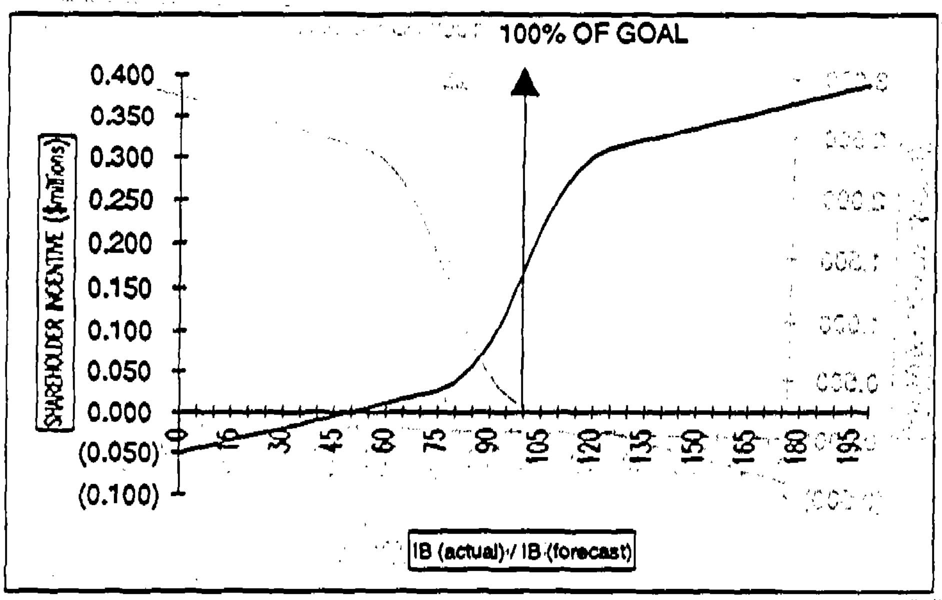
AGRICULTURAL ENERGY EFFICIENCY INCENTIVES



IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)
0	($0.05)	55	$0.01	110	$0.25	165	$0.35
5	($0.05)	60	$0.01	115	$0.28	170	$0.36
10	($0.04)	65	$0.02	120	$0.30	175	$0.36
15	($0.04)	70	$0.02	125	$0.31	180	$0.37
20	($0.03)	75	$0.03	130	$0.31	185	$0.37
25	($0.03)	80	$0.04	135	$0.32	190	$0.38
30	($0.02)	85	$0.05	140	$0.32	195	$0.38
35	($0.02)	90	$0.08	145	$0.33	200	$0.39
40	($0.01)	95	$0.12	150	$0.33		
45	($0.01)	100	$0.17	155	$0.34		
50	$0.00	105	$0.21	160	$0.34		

	(millions)
TOTAL RESOURCE BENEFIT (TRB)	$7.07
UTILITY ADMINISTRATION COST (UAC)	$0.40
UTILITY INCENTIVE COST (UIC)	$1.18
PARTICIPANT COST (PC)	$1.00
TARGET INCENTIVE	$0.17
TOTAL EFFECTIVE INCENTIVE %	3.00%

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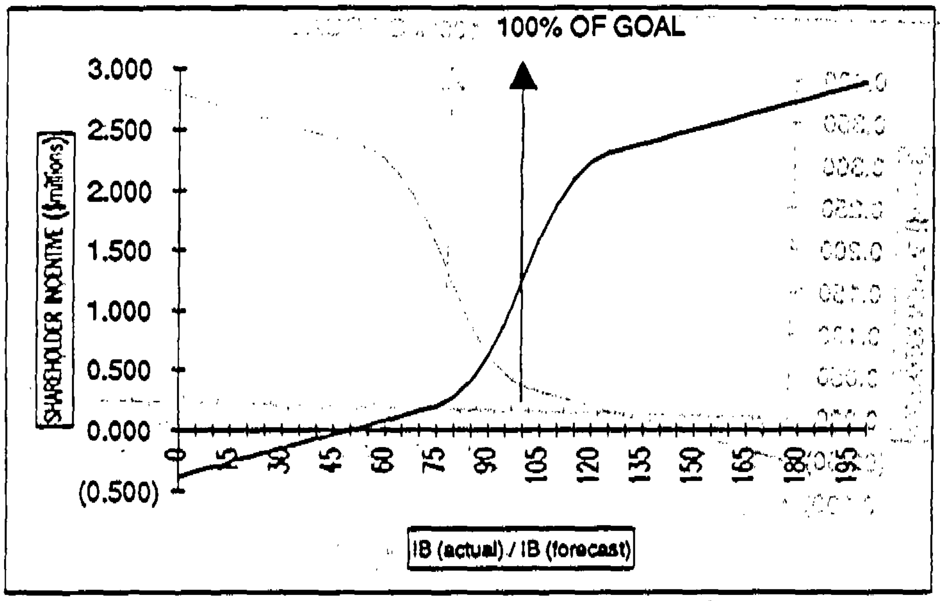
DIRECT ASSISTANCE (NON-MANDATORY)



IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)
0	($0.38)	55	$0.04	110	$1.88	165	$2.61
5	($0.35)	60	$0.08	115	$2.09	170	$2.65
10	($0.31)	65	$0.12	120	$2.23	175	$2.68
15	($0.27)	70	$0.15	125	$2.30	180	$2.72
20	($0.23)	75	$0.19	130	$2.34	185	$2.76
25	($0.19)	80	$0.26	135	$2.38	190	$2.80
30	($0.15)	85	$0.41	140	$2.42	195	$2.84
35	($0.12)	90	$0.62	145	$2.45	200	$2.88
40	($0.08)	95	$0.90	150	$2.49		
45	($0.04)	100	$1.25	155	$2.53		
50	$0.00	105	$1.60	160	$2.57		

	(millions)
TOTAL RESOURCE BENEFIT (TRB)	$26.00
UTILITY ADMINISTRATION COST (UAC)	$11.77
UTILITY INCENTIVE COST (UIC)	$0.00
PARTICIPANT COST (PC)	$0.00
TARGET INCENTIVE	$1.25
TOTAL EFFECTIVE INCENTIVE %	8.76%

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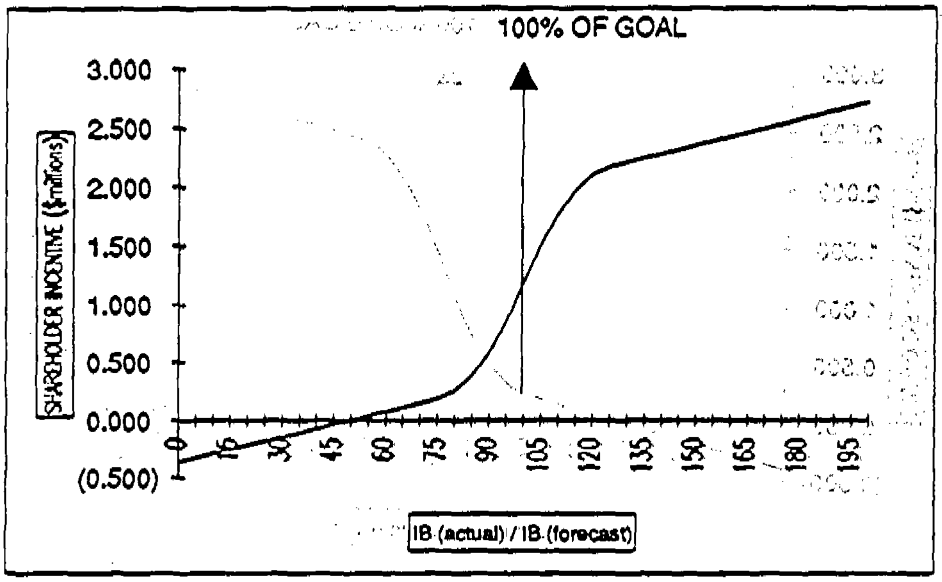
RESIDENTIAL NEW CONSTRUCTION ENERGY EFFICIENCY INCENTIVES



IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)
0	($0.36)	55	$0.04	110	$1.77	165	$2.46
5	($0.33)	60	$0.07	115	$1.97	170	$2.50
10	($0.29)	65	$0.11	120	$2.10	175	$2.53
15	($0.25)	70	$0.14	125	$2.17	180	$2.57
20	($0.22)	75	$0.18	130	$2.21	185	$2.60
25	($0.18)	80	$0.25	135	$2.24	190	$2.64
30	($0.14)	85	$0.38	140	$2.28	195	$2.68
35	($0.11)	90	$0.58	145	$2.31	200	$2.71
40	($0.07)	95	$0.85	150	$2.35		
45	($0.04)	100	$1.18	155	$2.39		
50	$0.00	105	$1.50	160	$2.42		

	(millions)
TOTAL RESOURCE BENEFIT (TRB)	$33.15
UTILITY ADMINISTRATION COST (UAC)	$6.77
UTILITY INCENTIVE COST (UIC)	$4.33
PARTICIPANT COST (PC)	$12.39
TARGET INCENTIVE	$1.18
TOTAL EFFECTIVE INCENTIVE %	6.52%

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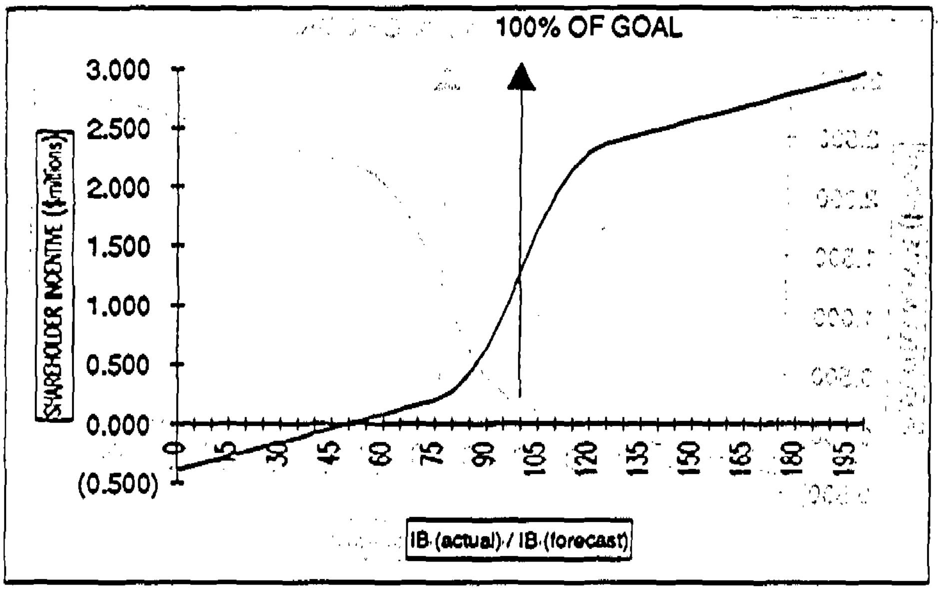
NON-RESIDENTIAL NEW CONSTRUCTION ENERGY EFFICIENCY INCENTIVES



IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)	IB (%)	Incentive (million)
0	($0.39)	55	$0.04	110	$1.93	165	$2.68
5	($0.35)	60	$0.08	115	$2.14	170	$2.72
10	($0.32)	65	$0.12	120	$2.29	175	$2.76
15	($0.28)	70	$0.16	125	$2.36	180	$2.80
20	($0.24)	75	$0.20	130	$2.40	185	$2.84
25	($0.20)	80	$0.27	135	$2.44	190	$2.88
30	($0.16)	85	$0.42	140	$2.48	195	$2.92
35	($0.12)	90	$0.63	145	$2.52	200	$2.95
40	($0.08)	95	$0.92	150	$2.56		
45	($0.04)	100	$1.28	155	$2.60		
50	$0.00	105	$1.64	160	$2.64		

	(millions)
TOTAL RESOURCE BENEFIT (TRB)	$47.91
UTILITY ADMINISTRATION COST (UAC)	$4.07
UTILITY INCENTIVE COST (UIC)	$8.02
PARTICIPANT COST (PC)	$15.71
TARGET INCENTIVE	$1.28
TOTAL EFFECTIVE INCENTIVE %	4.00%

(END OF APPENDIX G)

GLOSSARY

A.	Application
A&G	administrative and general
AER	Annual Energy Rate
AFUDC	allowance for funds used during construction
Alamitos	Alamitos Generating Station
ALBRR	authorized level of base rate revenues, or margin
ALJ	Administrative Law Judge
APS	Arizona Public Service Company
Arco-Watson	Watson Cogeneration Company facility at ARCO Petroleum Products Company
BiCEP	Big Creek Expansion Project
CACD	Commission Advisory and Compliance Division
CAL	Confirmatory Action Letter
Cal Energy	California Energy Company
CAL-SLA	California City-County Street Light Association
CBOs	East Los Angeles Community Union, Maravilla Foundation, and Veterans in Community Service
CEC	California Energy Commission
CFBF	California Farm Bureau Federation
CFC	chlorofluorocarbon
CLECA	California Large Energy Consumers Association
Coalition	California Energy Coalition
COTP	California-Oregon Transmission Project
CPCN	Certificate of Public Convenience and Necessity
CTAC	Customer Technology Applications Center
D.	Decision
Diablo Canyon	Diablo Canyon Nuclear Power Plant
DPV2	Devers-Palo Verde transmission line No. 2
DRA	Division of Ratepayer Advocates
DSM	demand side management
DSM rulemaking	R.91-08-003 and I.91-08-002
EAP	Engineering Assessment Program
ECAC	Energy Cost Adjustment Clause
Edison	Southern California Edison Company

APPENDIX H
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EEI	Edison Electric Institute
EPRI	Electric Power Research Institute
ER90	1990 Electricity Report
ERAM	Electric Revenue Adjustment Mechanism
ERI	Energy Reliability Index
FASB	Financial Accounting Standards Board
FEA	Federal Executive Agencies
FEIP	funding, evaluation, and implementation principles
FERC	Federal Energy Regulatory Commission
GRC	general rate case
GWh	gigawatt-hours
HVDC	high voltage direct current
I.	Investigation
IB	incentive basis
IER	incremental energy rate
IRC	Internal Revenue Code
IRS	Internal Revenue Service
IU	Industrial Users
KRCC	Kern River Cogeneration Company
kW	kilowatts
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water and Power
MAAC	Major Additions Adjustment Clause
Mission Energy	Mission Energy Company and Mission Group
MWe	megawatts electric
MWh	megawatt-hours
NMRC	Nuclear Management and Resource Council
NOI	Notice of Intent
NOx	nitrogen oxides
NRC	Nuclear Regulatory Commission
NRDC	National Resources Defense Council
O&M	operations and maintenance
Palo Verde	Palo Verde Nuclear Generation Station
PBOP	post-retirement benefit other than pensions
PC	participant costs
PG&E	Pacific Gas and Electric Company

PHFU	property held for future use
PSD	Public Staff Division, predecessor to DRA
PU Code	Public Utilities Code
PWR	pressurized water reactor
QF	qualifying facility
R.	Rulemaking
RD&D	research, development, and demonstration
r-squared	a statistical measure of correlation
ROE	return on equity
SCR	selectric catalytic reduction
SDG&E	San Diego Gas & Electric Company
Section 42	Arizona Revised Statute Section 42-144.02
SoCalGas	Southern California Gas Company
SONGS	San Onofre Nuclear Generating Station
SSP	Stock Savings Plan
Sycamore	Sycamore Cogeneration Company
TCF	target capacity factor
TFP	total factor productivity
TI/PV	Texas Instruments photovoltaic
TOU	time-of-use
TRB	total resource benefits
TRC	total resource costs
TURN	Toward Utility Rate Normalization
UAC	utility administrative costs
UIC	utility incentive costs
VEBA	Voluntary Employee Benefit Association
WMBE	Women and Minority Business Enterprises
WTF	water treatment facility
Yuma Axis	Yuma Axis Generation Station

(END OF APPENDIX H)