ALJ/RAB/sid **Mailed 11/5/99**

Decision 99-11-022 November 4, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of the SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for: (1) Review of the Reasonableness of SCE's Operations During the Period from April 1, 1997 through December 31, 1997; (2) Recovery of Cost Tracked in the ISO/PX Implementation Delay Memorandum Account; (3) Reasonableness Review of Special Contracts Administration; and (4) Electric Vehicles Program Costs for the Period from January 1, 1998 through April 30, 1998.	Application 98-05-053 (Filed May 29, 1998)

James P. Scott Shotwell, Attorney at Law, for Southern California Edison Company, applicant.
Robert C. Cagen, Attorney at Law, for the Office of Ratepayer Advocates.

OPINION

Southern California Edison Company (SCE) seeks an order finding reasonable (1) its operations from April 1, 1997 through December 31, 1997; (2) those Energy Cost Adjustment Clause (ECAC) and Electric Revenue Adjustment Mechanism (ERAM) related costs booked to the Independent System Operator/Power Exchange (ISO/PX) Implementation Delay Memorandum Account from January 1, 1998 through March 31, 1998; (3) its special contract administration for the period April 1, 1997 through March 31, 1998; and (4) the costs of the Electric Vehicle Program incurred during the periods April 1, 1997 through April 30, 1998.

More specifically, SCE requests findings that:

1. SCE's operations and its fuel and energy-related costs recorded in the ECAC balancing account from April 1, 1997 through December 31, 1997, were reasonable;

2. SCE's administration of its purchased power agreements with qualifying facilities (QFs) during the Record Period, and the associated purchased power expenses in the ECAC balancing account were reasonable for the period from April 1, 1997 through December 31, 1997;

3. SCE be authorized to recover the costs recorded in the ISO/PX Implementation Delay Memorandum Account;

4. SCE's administration of its Special Rate Agreements from April 1, 1997 through December 31, 1997 and January 1, 1998 through March 31, 1998 were reasonable; and

5. SCE's Electric Vehicle Programs have been reasonably implemented and costs thereunder were reasonably incurred from April 1, 1997 through December 31, 1997, and from January 1, 1998 through April 30, 1998.

Decision (D.) 97-10-057 eliminated the ECAC balancing account and ECAC proceedings for generation costs beginning January 1, 1998. Therefore, the last ECAC reasonableness Record Period runs from April 1, 1997 through December 31, 1997. The Coordinating Commissioner's Ruling (CCR) dated May 14, 1998 in Rulemaking (R.) 94-04-031 and Investigation (I.) 94-04-032, specified that SCE should seek recovery of the costs recorded in the ISO/PX Implementation Delay Memorandum Account authorized by D.97-12-131 and the review of reasonableness issues regarding electric vehicles as part of its ECAC application. SCE has complied with the CCR.

ORA reviewed the reasonableness of operations of SCE and found the operations reasonable except for two incidents regarding coal generation operations at the Mohave and Four Corners power plant, and errors in SCE's balancing accounts. ORA's conclusions and recommendations are:

a. There was a December 1997 outage of Mojave Units 1 and 2 due to direct current (DC) control system grounds which were caused by relays incorrectly assembled by the relays' manufacturer. The ratepayers should not pay for the mistakes made by the manufacturer of these relays. ORA recommends a disallowance of $2.4 million.

b. There were outages at Four Corners Unit 5 which were caused by problems with a high pressure (HP) generator field. The outages were unreasonable because the operator of the unit failed to replace the field with new wiring, as the manufacturer had recommended. The field had repeated failures and was rewound in March 1996 with old wire, against the manufacturer's recommendation. It had operated less than 16 months when it failed in 1997. The ratepayers should not pay for the added fuel cost associated with a field that did not meet the industry's expected life and which was not replaced as recommended by the manufacturer. ORA recommends a disallowance of $15.7 million.

ORA's analysis of SCE's balancing accounts revealed errors. Because the balancing accounts no longer exist, all corrections are recommended to be made to the Transition Cost Balancing Account (TCBA). ORA recommends that the TCBA be credited for $4.106 million, plus interest, to correct for SCE's errors stemming from SCE's erroneous removal of Franchise Fees and Uncollectibles (FF&U) from the overcollection in the Interim Transition Cost Balancing Account (ITCBA) and ERAM balancing accounts.

SCE disputed ORA's proposed disallowances. Public hearing was held before ALJ Robert Barnett and the matter was submitted subject to receipt of briefs.

1. Mohave Units 1 and 2 Relay Failures

The two relays that failed were the ARS relay at Unit 2 and the Moore device at Unit 1. The ARS relay is high speed, low energy signal auxiliary relay for the TEX relay, a device in the Sub-Synchronance Resonance Scheme, which monitors system disturbances in the units. The Moore device is a temperature monitoring device for Unit 1's turbine exhaust hood.

In December 1997, a terminal in the ARS relay was touching the relay case. This relay had been installed on the unit in 1976 and had not been removed from its socket since its initial installation. After being in this position for approximately 20 years, the terminal wore through the enamel paint on the relay case, creating a positive ground on the common DC battery circuit for both Units 1 and 2, which, in turn, created an increase in voltage across an insulation in the Moore device, not intended for high DC voltages. The high voltage across the installation began to arc and burn, which created a negative ground on the DC circuit. The fluctuating DC voltage due to the negative ground created by the Moore device in conjunction with the positive ground associated with the ARS relay caused the ARS relay to activate and hold for 2-1/2 seconds. The ARS relay coil is very sensitive, requiring only 15 to 20 volts and 6 milliamps to activate. This started a trip sequence for Unit 2 and it went off-line.

At the same time, the grounds on the Unit 1 Moore device burned clear, but the continuing arcing on the device associated with the initial increased voltage caused the Moore device to continue to arc. This prolonged arcing caused additional shorts in the "ribbon bus" and the Moore device's thermocouple external terminals for the exhaust hood were shorted together. This shorting activated the high temperature exhaust hood trip circuit, which caused a false trip on Unit 1. The unit went off-line approximately five minutes after Unit 2.

SCE determined that this outage was due to the failure of a relay that had been incorrectly assembled by the manufacturer. SCE states that it did not operated the relays in an unreasonable manner. In its opinion, outages that are beyond human control are part of normal utility operations. There was nothing unreasonable or imprudent in SCE's operation of the plant prior to the outage, or the manner in which it addressed the problem. The outage was directly linked to the initial ground created by the terminal on the ARS relay touching the relay case which started a series of events that collectively caused both units to trip. The ARS relay had been in place and operated corrected for approximately 20 years. A component failure does not constitute grounds for a disallowance.

ORA does not contend that SCE unreasonably operating the relays. It agrees with SCE that the fault appears to be the manufacturer. However, ORA asserts that there should be a disallowance. ORA contends that SCE's shareholders may be made whole by making a claim or filing a lawsuit against the manufacturer for the amount of the disallowance or any other damages suffered from the bad relays.

ORA recommends a disallowance of $2.4 million. It claims the outage of Unit 1 lasted 33.92 hours and the outage of Unit 2 lasted 282.83 hours. The estimated added fuel cost associated with these outages based on the recorded average fuel cost differential of $16.93/MWh between SCE's gas fired units and coal generation at Mojave is $2.4 million ($2.4=790 MW*(33.92+282.83) Hr.*$16.93/MWh*.56%).

In the alternative, ORA recommends that the Commission require SCE to file a lawsuit on behalf of ratepayers against the relay manufacturer. In ORA's opinion, it is not good policy for a utility to permit a manufacturer to cause ratepayers to pay the significant expense of a faulty product.

The standard with which we are concerned in a reasonableness review is based on the activity of the utility. (D.86-10-069 (22 CPUC2d 124, 151).) We are concerned with the utility's reasonable or unreasonable activity, not that of a manufacturer. In regard to the Mojave incident it is clear, and ORA agrees, that SCE did not operate the relays in an unreasonable manner. Therefore, the only possible unreasonable conduct of the utility would be in its attempt to minimize damage. In this instance, to promptly repair the defect and to seek recompense from those who provided the faulty relays. Here, there is no evidence that SCE failed to act prudently in installing the relays or in repairing the damage; there is no basis for a disallowance. We are left, therefore, with a possible claim against the manufacturer.

ORA believes that SCE can be made whole by filing a claim or lawsuit against the manufacturer for the amount of the disallowance or any other damages shareholders suffered from the bad relays. In the event that the Commission does not adopt ORA's recommended disallowance, it recommends that the Commission order SCE to file a lawsuit on behalf of ratepayers against the manufacturer. However, ORA has presented no facts nor legal analysis to show that a cause of action against the manufacturer exists. SCE argues that it cannot seek such recovery and ORA's recommendation is inappropriate. SCE's witness testified that it did notify the manufacturer of the relay of its deficiency. He testified that the ARS relay had operated correctly for approximately 20 years, and was outside the warranty period. Moreover, the terms and conditions of the purchase contract do not provide for the manufacturer to indemnify the utility against replacement power costs.

Under the circumstances, we will not require the filing of a lawsuit. We find that SCE has operated reasonably in rectifying the Mohave outage.

2. Four Corners Unit 5 HP Generator Outages

ORA recommends a $15.73 million disallowance for three outages at the Four Corners generation facility from July 1997 through November 1997. Four Corners is operated by Arizona Public Service Company (APS). SCE is a partner in Four Corners. The outages were associated with a field ground in the Unit 5 HP steam generator (785 MW). A field ground exists when the electrical current breaches the insulation between the copper conductor and the steel body of the field. The current does not flow through the copper conductors, but is redirected through the field's steel body to the plant ground grid. This can severely damage the field rotor, bearings and gears, among other things.

The first indication of a field ground occurred on August 10, 1996, but the indication cleared once the unit speed exceeded 2,800 revolutions per minutes (RPM). Accordingly, APS continued to operate the unit, with the expectation that the unit could run until its next overhaul outage that was scheduled to occur in May 1999.

The unit had previously exhibited shorted turns, which occur when an electric current breaches the insulation between the copper conductors. Instead of the current flowing through the copper conductor of the field winding, it "jumps" to the next turn before completing its normal path through the entire length of the copper conductor. In late 1995, APS had asked General Electric (GE) to analyze the cause of the shorted turns and recommend a solution to be consider for the overhaul outage in early 1996. On February 9, 1996, GE issued its report recommending that the field be rewound using existing copper conductor, and that if the shorted turn returned, that the copper conductor be replaced at that time. Accordingly, APS rewound the rotor using the existing copper conductor. The overhaul outage ended on March 9, 1996 and Unit 5 went back on line.

On July 19, 1996, however, Unit 5 exhibited more shorted turns. Once again, APS asked GE to review the problem. On September 30, 1996, GE issued its Rotor End Winding Thermal Analysis, in which it determined the amount of damage to the field winding and copper. In this report, GE recommended that the field be rewound with new copper. However, manufacturing and testing of a new copper conductor takes approximately six months. Because of the long lead-time needed to manufacture and install new copper, and the desire to minimize total outage time of the unit, APS ordered a complete new generator field from GE, including new copper, on November 26, 1996, so that the new field could be installed expeditiously during the 1999 planned overhaul outage. APS was able to continue operating Unit 5 at full load with the shorted turns.

On July 1, 1997, APS found that the field ground condition, first observed on August 10, 1996, was actually not clearing under normal operating conditions. APS determined that operating the unit with a solid field ground condition posed an unacceptable risk to plant safety. The unit was removed from service on July 7, 1997, and GE repaired the ground coil on site in order to keep the unit running during the summer peak load season. However, on August 25, 1997, during start up from an unrelated unit trip, another field ground condition was detected. The unit was removed from service at that time and APS removed the field from the generator. Representatives from GE inspected it and determined that the copper conductors were in poor condition and recommended that the field ordered in November 1996 be installed. GE informed APS that all materials for the new field ordered in November 1996 were ready except for the steel rotor, or forging, which was not essential to the operation. The field was back on line November 1, 1997. Since November 1, 1997, Unit 5, with the new copper conductor, has had no recurring field ground. However, there is evidence of recurring shorted turns. These shorted turns indicate that the new copper installed in 1997 did not resolve the problems associated with the field, and the unique problems associated with Unit 5 continue to confound industry experts.

A witness for ORA testified that the HP generators at Four Corners Units 4 and 5 were built by GE and were commissioned in 1969 and 1970, respectively. Both generators operated as expected without problems until 1986 when GE recommended some modifications to mitigate copper dusting contamination of the field windings. The recommended modifications were made and the Unit 5 HP generator field was rewound in that year. Similar modifications were made to Unit 4 HP generator in 1989, which has operated without incident since then. However, because of repeated failures, the Unit 5 HP generator field was rewound in 1991, 1993, 1996, and in 1997.

During the record period, Unit 5 experienced three outages due to problems with the field of the HP generator. In July 1997, Unit 5 was removed from service due to a ground and several shorted turns in the HP generator field. GE performed the repair as a warranty claim because it had rewound the same field during the 1996 overhaul. This outage lasted 479.22 hours. In August 1997, it was discovered that the same field needed to be rewound. The Unit was out of service for 1,473 hours. In November 1997, Unit 5 was taken out of service for 24.65 hours to balance the HP generator, a requirement after the rewind of the field.

The witness agreed with SCE that the cause of repeated failures of the field is unclear. ORA is not attempting to determine the cause of these failures, but it points out that Unit 4 did not experience any of the problems experienced by Unit 5. The witness is of the opinion that in the course of implementing the modifications recommended by GE, either the materials or the workmanship used in the field rewind job on Unit 5 were inferior to those on Unit 4. He said there is evidence that as early as 1986 GE had recommended that the field copper should be replaced. The witness testified that in 1995, GE recognized that this field had failed three times in the last five years, and recommended the use of new copper in the next rewind job to prevent the same problems from recurring in the future. However, when the field was rewound in 1996, APS declined the recommendation and instead ordered a rewinding using the existing copper, which had already failed on multiple occasions. In the witness' opinion, the installation of new copper in the 1996 rewind as recommended by GE in 1995 would likely have prevented the 1997 failure and the added fuel cost associated with it. APS finally rewound the field with new copper after the 1997 failure.

The same HP generator field was rewound an unprecedented four times in less than seven years while the identical generator of Unit 4 has operated with no problems since its commissioning in 1969. ORA argues that the frequency of failure of this particular HP generator field is unacceptable by any standard. It is the owner/operator's responsibility to prevent the premature failure of this field, and SCE's ratepayers should not be burdened by the added cost associated with the outages caused by this field during the record period. In this instance, ORA maintains that the owner/operator acted unreasonably and caused the 1997 outage and its associated costs. The field prematurely failed at least four times by 1997. The field's manufacturer, the expert on the field, in 1995 recommended that the field be rewound with new copper wire. If the plant operator had followed that recommendation, ORA states that the 1997 outage most likely would not have occurred.

During the record period, Four Corners Unit 5 was out of service for a total of 1,976.87 hours due to problems with the HP generator field. The estimated added fuel cost associated with these outages based on the recorded average fuel cost differential of $21.12 MWh between SCE's gas fired units and coal generation at Four Corners is $15.73 million ($15.73=785 MW*1,976.87 Hr.* $21.12

MWh*.48%). ORA recommends the disallowance of the additional $15.7 million in fuel costs.

ORA's case in a nutshell is the following: The Unit 5 field rewind with existing copper failed multiple times and over a long period of time. The failures were unprecedented in the industry. Both the field generator manufacturer and consultants repeatedly told APS and SCE that a rewind with existing copper was not reliable or effective. Yet APS and SCE continued, time after time, to try to rewind the field with existing copper, rather than to purchase new copper. The cost of a new copper rewind was reasonable, especially compared to the cost of continued unit failures and rewinds using existing copper. SCE and APS finally decided to order new copper, but the decision came too late to prevent another outage during the record period from failed existing copper. After the rewind with new copper, the Unit has operated well and without serious field problems. ORA contends that its case does not depend on whether a particular manufacturer's report or a particular event should have earlier triggered APS and SCE to rewind the field with new copper. A disallowance is compelled because of the entire historical record of Unit 5, and because of the many and repeated indications over a long time that rewinds with existing copper were ineffective.

SCE asserts that APS did not ignore any prior recommendations to install new copper conductor. SCE says that ORA's allegation that APS ignored a recommendation by GE in 1995 to install a new copper conductor, which would have allowed it to install the new copper conductor during the scheduled major overhaul beginning in January, 1996, is mistaken. SCE states that the first time GE definitively recommended the installation of new copper conductor was in its September 30, 1996 report issued after investigating the additional shorted turn APS observed on July 19, 1996. As a result, APS ordered a complete new generator field from GE on November 26, 1996. This new field was to be installed during the next scheduled overhaul outage.

SCE argues that ORA's mistaken belief that GE recommended the installation of new copper conductor as far back as 1995 results from what SCE believes is a typographical error contained in GE's Generator Field Winding and Insulation Report, dated October 28, 1997. The report states:

> "A meeting was held with APS at the Four Corners site in January, 1995 ..."

SCE's witnesses testified that the reference to January, 1995 is erroneous. There is no record that GE employees investigated the issue in 1995. There are no notes or logs indicating that GE visited Unit 5 during that time and APS has no contracts or purchase orders associated with a GE visit to Unit 5 during 1995. However, the author of the October 28, 1997 report did participate in the engineering field work at Four Corners in January, 1996, which led to the preparation of the February 9, 1996 report in which GE recommended that the generator field be rewound with new copper conductor if the shorted turn problems persisted.

An SCE witness testified that there were no recommendations to replace the copper conductor in 1995 or earlier. SCE believes that APS did everything it could to save ratepayers money. First, in September 1996, when GE recommended that the copper conductor be replaced, APS ordered a complete new generator field. This was done so that the new field could be installed within a short amount of time during the next scheduled overhaul. Because of this action, new copper conductor was on hand when APS needed to rewind the unit beginning in September, 1997, which saved at least 85 days of outage time.

Second, while the unit had to be rewound once to address the issues raised in the Technical Information Letter and three times to address shorted turns, APS was able to schedule each of the rewinds during a scheduled overhaul outage. This allowed APS to continue operating the unit and generating electricity for the benefit of ratepayers. When the field ground condition was confirmed on July 1, 1997, APS and GE attempted to repair the coil on site to minimize downtime during the summer peak load conditions when replacement power costs tend to be higher. However, on August 25, 1997, another field ground condition was detected and the unit was removed from service. GE and APS inspected the unit and determined that the grounded section of the copper conductors was in such poor condition that the new generator field should be installed. APS inquired whether the field ordered in November, 1996, was ready. Although the entire new field was not ready, the materials ordered for the new field, including the new copper conductor, were ready. As a result, based on GE's recommendation, APS rewound the existing generator field forging with new copper conductor and the unit was returned to service on November 1, 1997.

SCE concludes that at all times APS acted to minimize down time, acted after consulting with experts, acted on the experts' recommendations, and acted to minimize costs.

3. Discussion

We agree with ORA that the timing of prior warnings regarding the need to use new copper is not critical to the outcome of this proceeding. Had there been a definite recommendation to use new copper, our view of the evidence might be different, but the recommendations, at least until 1996 were, in our opinion, equivocal; that is, they were always couched in the alternative. We believe that ORA has failed to give proper weight to the different consequences of shorted turn problems as contrasted with field ground problems.

The generator field operated well until about 1991. The 1986 rewind was performed in accordance with Technical Information Letter Number 965 issued by GE in 1983, which applied to all generation units with the same type of field, including SCE's Mohave units. This technical information letter recommended a rewind of Units 4 and 5, using existing copper conductor. APS did not perform this rewind because of any problems it had experienced with the Unit 5 generator prior to that time and rewound the generator field with existing copper conductor based on the specific recommendation in the technical information letter. After the 1986 rewind, Unit 5 was rewound with existing copper conductor in 1991, 1993, and 1996. In 1997, the new copper conductor was installed.[1]

The prior rewinds were done to correct shorted turn problems as opposed to the field ground which was first observed in August 1996 and later confirmed in July 1997. Prior to the field ground, APS elected to rewind the field generator with existing copper, based on the recommendations of GE and other consultants. The cause of the shorted turns baffled APS and industry experts and there was no guarantee that the installation of new copper conductor would solve the problem. Moreover, APS was able to continue to operate Unit 5 throughout this time, allowing it to conduct each of the rewinds during

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[1] Each of the prior rewinds occurred during prior ECAC record periods and were, thus, the subject of other proceedings. ORA and its predecessors reviewed those outages and never recommended any disallowances associated with rewinds at Unit 5 in those proceedings. (*See* D.92-06-059, 44 CPUC2d 644; D.95-11-063, 62 CPUC2d 505; and D.98-10-054, 1998, Cal. PUC Lexis 1004.)

scheduled outages to avoid incurring replacement energy costs. There was no need to incur the expense and down time of a rewind with new copper to correct the short turn problems. It was only when the field ground occurred that new copper became mandatory.

The evidence persuades us that APS never received a definitive recommendation to install new copper conductor until GE issued its September 30, 1996 report. ORA claims that GE recommended this course of action much earlier. It relies on two documents. The first document is an electronic mail note of December 4, 1996. This note alludes to a 1986 recommendation to install new copper. However, the rewind conducted by GE in 1986 was pursuant to the technical information letter that recommended "completely rewind[ing] the field, using the existing copper [conductor]. (Exhibit 23, p. 3.) At that time, there would have been little, if any, need for GE to render such an opinion given that the first shorted turn problems were corrected in 1991.

ORA also relies on GE's report, dated October 28, 1997, which refers to a recommendation to install new copper conductor in January 1995. This is typographical error. The reference to 1995 was most likely to GE's recommendation in early 1996 that the generator field be rewound with new copper if the shorted turn problems persisted. This is consistent with the reports regarding Unit 5 during this time.

A short or field ground could occur at anytime. ORA argues that the problems at Unit 5 were so bad that APS should have ordered new copper wire at a time earlier than November 1996 so that the rewind could have taken place at an earlier planned outage, thereby averting the unplanned outages that occurred in 1997. ORA's reasoning is not persuasive. In our view, given the complexity of the repair, the long lead time to order and receive replacement parts, the length of time need to make the repair, and the substantial cost of replacement power while making the repair, APS acted reasonably in trying to keep Unit 5 operating with as little downtime as possible.

We agree that had Unit 5 been rewound with new copper in the January 1996 schedule outage, there might not have been the outage in 1997. But to rewind with new copper in January 1996 would have required placing the order in early 1995 to assure timely delivery. So if failure had occurred in late 1995 with an unscheduled outage costing $15 million, the argument could easily be made that because of the unsuccessful rewinds in 1991 and 1993, APS acted unreasonably in delaying ordering new copper until 1995.

In every major failure of Unit 5, APS consulted outside experts. If they had recommended rewiring with new copper and APS had failed to heed the recommendation our view of the reasonableness of APS' action would be different. But they did not (until September 1996) and our view is unchanged. We disagree with ORA's characterization that SCE was repeatedly told that a rewind with existing copper was not reliable or effective. Rewiring with new copper was always an alternative from the very beginning of the Unit 5 problems, but until September 1996, it was never other than an option. It was expensive; it required a long lead time; and it required extended downtime to complete repairs. We cannot fault APS for applying the repair that was the least costly and required the least downtime. SCE's (and APS') conduct was reasonable.

4. Balancing Accounts

ORA recommends that SCE credit the TCBA in the amount of $4.1 million to reflect the FF&U amount that ORA alleges SCE erroneously deducted from overcollected balances recorded in the ITCBA and the ERAM prior to transferring those balances to the TCBA. SCE does not agree, and asserts that if ORA's position is adopted, SCE will be denied recovery of authorized expenses associated with FF&U.

In SCE's test year 1995 general rate case, the Commission authorized recovery of FF&U, and adopted a factor of 1.0113. This FF&U factor is multiplied by the sum of the return on rate base and operating expenses when calculating the total authorized revenue requirement. (D.96-01-011, Appendix D.) For every dollar SCE bills, it is authorized to recover approximately one cent for franchise fee obligations and uncollectible amounts.

D.96-12-077 authorized SCE to establish the ITCBA as a placeholder account in which the December 31, 1996 balances in both the ERAM and ECAC balancing accounts were transferred on January 1, 1997. As shown in Table I, below, the combined December 31, 1996 ECAC and ERAM overcollected balance of $219.827 million was transferred to the ITCBA on December 31, 1996, which accrued interest throughout 1997. The ending December 31, 1997 overcollected balance of $232.993 million in the ITCBA was transferred to the TCBA on January 1, 1998 after adjusting for FF&U.

Table I
Amounts Transferred to TCBA
January 1, 1998
($000)
(Over)- /Undercollections

	12/31/96 Balance	FF&U Adjtmnt.	1997 Interest	12/31/97 Balance	FF&U Adjtmnt.	Transferred Amount
ECAC	(52,838)	(599)	(3,046)	(56,483)	633	(55,850)
ERAM	(166,989)	N/A	(9,520)	(176,510)	1,980	(174,530)
ITCBA	(219,827)	(599)	(12,566)	(232,993)	2,613	(230,380)
ECAC				485,142	0	485,142
ERAM				(189,491)	2,126	(187,365)
Total Amount Transferred to TCBA						(67,397)

In addition, pursuant to D.97-11-074, SCE also transferred the December 31, 1997 overcollected ERAM balance in the amount of $187.365 million and the undercollected ECAC balance in the amount of $485.142 million to the TCBA on January 1, 1998. In each case, FF&U was removed prior to the balance being transferred to the TCBA.

ORA asserts that SCE should not have adjusted its ERAM balancing account and ITCBA balances for FF&U prior to transferring these balances to the TCBA. ORA claims that SCE should have transferred $176.510 million associated with the ERAM component of the December 31, 1997 ITCBA balance and $189.491 million associated with the December 31, 1997 ERAM balance to the TCBA. Table II, below, summarizes the difference between ORA's and SCE's position on the amounts that should have transferred to the TCBA on January 1, 1998.

Table II
Transferred Amounts At Issue
($000)
(Over-) /Undercollections

	SCE	ORA	Difference At Issue
ITCBA/ERAM	(174,530)	(176,510)	(1,980)
1997 ERAM	(187,365)	(189,491)	(2,126)
Total	(361,895)	(366,001)	(4,106)

SCE argues that it correctly adjusted its TCB account in conformity with Commission decisions and applicable statutes. For every dollar SCE bills, it is authorized to recover approximately one cent in FF&U to pay for franchise fee obligations and uncollectible amounts. The ERAM balancing account was established in 1981 to protect electric utilities from the risk of inaccurate sales forecasts and to eliminate the disincentive for conservation programs. (7 CPUC2d 349, 394.) There was no need to adjust the amounts recorded in the ERAM balancing account for FF&U because the account compared billed base rate revenue with authorized base rate revenue, both of which included a component for FF&U. Any over- or undercollection, which already included FF&U, would increase or decrease the otherwise applicable ERAM revenue requirement for the subsequent year, which also included FF&U, and this revenue requirement would be used to establish the electric revenue adjustment billing factors.

The ECAC balancing account, on the other hand, was established in 1976 to alleviate the impacts on utilities of volatile fuel costs.[2] The ECAC balancing account compared ECAC costs and ECAC revenues. Because recorded ECAC costs does not include FF&U, the FF&U was removed from the billed ECAC revenues to yield recorded ECAC revenues, so that like-revenues and expenses were compared. Prior to disposing of the ECAC balancing account balance, any over- or undercollection in the ECAC balancing account would first have to be converted to a revenue requirement by adjusting for FF&U. This revenue requirement would either be added to the subsequent year's ECAC revenue requirement, which is used to set the energy cost adjustment clause billing factors (ECABF), or returned to ratepayers as a bill credit. In either event, the revenue requirement would have been adjusted to reflect FF&U.

The ITCBA was established in 1996 to track transition cost recovery prior to 1998 by debiting the transition costs the Commission authorizes and crediting collected headroom revenues.[3] Accordingly, pursuant to § 368(a), the December 31, 1996 balances in the ERAM and ECAC balancing accounts were recorded in the ITCBA. The amount transferred from the ECAC balancing account was grossed up to include FF&U before being transferred to the ITCBA. Because the TCBA tracks the recovery of transition costs, which do not include FF&U, SCE stated that it removed the FF&U from the December 31, 1997 balances in the ERAM balancing account and the ITCBA before transferring those amounts to the TCBA. Otherwise, SCE contends, the FF&U portion of any

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[2] D.85731, mimeo., pp. 3, 5, 20-21 (Finding of Fact 6), 22 (Finding of Fact 8), 79 CPUC 758.

[3] D.96-12-077, mimeo., pp. 13-14, 1996 Cal. PUC Lexis 1109, 175 P.U.R, 4th 65.

overcollection in these amounts would go to pay off transition costs, even though SCE had already paid those same dollars to municipalities and other agencies as franchise fees or absorbed uncollectible amounts billed to customers.

Section 368(a) provides that the ECAC and ERAM balancing account overcollections should be transferred to the TCBA. SCE argues that it should not be read so literally as to prevent the appropriate accounting and ratemaking adjustments for FF&U, which have always been made to these accounts. SCE believes that such a literal interpretation would not only ignore the operational differences between the accounts and lead to a mismatch between revenues and expenses, it would also deny SCE the opportunity to recover reasonably incurred costs. SCE also asserts that such an interpretation would violate §§ 330(s), 368(a), and 369 of the Pub. Util. Code, which provide SCE the opportunity to recover its transition costs during the transition period, and § 451, which allows SCE to recover its reasonable operating costs.

SCE states that its FF&U adjustments are consistent with the manner in which other utilities administer their accounts and have been audited pursuant to D.97-11-074. It claims that both San Diego Gas & Electric Company (SDG&E) and Pacific Gas and Electric Company (PG&E) make similar adjustments for FF&U to the balances recorded in their transition cost balancing accounts. In addition, pursuant to D.97-11-074, the Commission's Energy Division commissioned an independent audit of PG&E, SDG&E, and SCE's balances transferred to their respective transition cost balancing accounts and headroom revenues.[4] The audit report issued in December, 1998, stating that SCE had

[4] D.97-11-074, mimeo., p. 164, 1997 Cal. PUC Lexis 1093.

correctly transferred the balances in the ECAC and ERAM balancing accounts and the ITCBA, among other accounts, to the TCBA as of January 1, 1998:

> "Balances in the ECAC, ERAM, ITCBA and the SONGS and Palo Verde Balancing Accounts were appropriately transferred to the TCBA as of January 1, 1998. Balances in the Palo Verde Sunk Costs Memorandum Account and SONGS 2 & 3 Sunk Cost Memorandum Accounts were reasonable, and were properly closed to the TCBA as of January 1, 1998."[5]

SCE claims that prior ECAC decisions have specifically acknowledged the need for an FF&U adjustment. D.92-01-018, the 1992 ECAC decision, specifically adjusted the ECAC revenue requirement, which was used to set the ECABF, to reflect FF&U expenses.[6] Four of the final six ECAC decisions specifically set forth the FF&U adjustment.[7] While there may be no Commission decisions specifically authorizing SCE to deduct FF&U from the December 31, 1997 balances in the ERAM balancing account and the ITCBA before they were transferred to the TCBA, the adjustments are entirely consistent with past practices and the manner in which these accounts operate.

SCE claims that a $4.1 million adjustment associated with the FF&U in the ERAM balancing account would have to be reduced by $2.068 million reflecting the FF&U that otherwise would not have been deducted from other balancing and memorandum accounts. Both SCE's and ORA's witnesses testified that the

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[5] Exh. 35, p. IV-29.

[6] D.92-01-018, Attachment B, in 24, 43 CPUC2d 50, 80.

[7] *See* D.90-01-048, Appendix C, 35 CPUC2d 169 (1990 ECAC); D.90-12-067, Appendix B, Ln. 4 (1991 ECAC) 38 CPUC2d 452; D.92-01-018, Attachment B, Appendix B, Ln 24, 43 CPUC2d, 50, 75-76, 80 (1992 ECAC); D.96-02-071, Appendix C, p.14, Ln. 24, 65 CPUC2d 33, 55-57 (1996 ECAC).

balances in the ERAM balancing account and the ITCBA are not the only balances that are adjusted in the FF&U prior to being transferred to the TCBA. Similar adjustments were required for the 1997 SONGS 2 & 3 Incremental Costs Incentive Pricing Balancing Account, the 1997 SONGS 2 & 3 Sunk Costs Memorandum Account, and the 1997 Palo Verde Sunk Costs Memorandum Account. SCE argues that if the Commission were to decide that the FF&U adjustments associated with the ERAM balancing account and the ITCBA is inappropriate, adjustments for FF&U in each of the remaining balancing accounts, totaling $2,068,000, would also have to be reversed in order for the accounts to be handled on a consistent basis.

5. Discussion

The ITCBA was created in January 1997 pursuant to Assembly bill (AB) 1890 and D.96-12-077. One purpose of the ITCBA was to record the overcollections in the ECAC and ERAM balancing accounts as of December 31, 1997. The ITCBA was designed to provide a transition from traditional cost-based ratemaking to ratemaking associated with the rate freeze and enhanced transition cost recovery.

The effect of SCE's failure to transfer FF&U is to unlawfully shift to ratepayers the risk of nonrecovery of overcollected FF&U costs. Before AB 1890, overcollections in the ERAM balancing account were refunded or amortized during the next ECAC record period. In this way, ratepayers who had overpaid through a revenue overcollection for FF&U during one year were made whole during the next year by a refund or rate reduction sufficient to amortize the overcollection.[8] The rate freeze ended this amortization procedure.

The legislature enacted AB 1890 as part of the transition to electric restructuring. In so doing, the legislature codified a particular level of risk and reward that it deemed appropriate to assign to utility shareholders and to utility ratepayers. SCE now seeks to change that legislative balance to the detriment of its ratepayers.

The relevant portion of AB 1890, as codified by §§ 368 and 368(a) directs as follows:

> "Each electrical corporation shall propose a cost recovery plan to the commission for the recovery of the uneconomic costs of an electrical corporation's generation-related assets and obligations identified in Section 367. The commission shall authorize the electrical corporation to recover the costs pursuant to the plan if the plan meets the following criteria:
>
> "(a) The cost recovery plan shall set rates for each customer class, rate schedule, contract, or tariff option, at levels equal to the level as shown on electric rate schedules as of June 10, 1996, provided that rates for residential and small commercial customer shall be reduced so that these customers shall receive rate reductions of no less than 10 percent for 1998 continuing through 2002. These rate levels for each customer class, rate schedule, contract, or tariff option shall remain in effect until the earlier of March 31, 2002, or the date on which the commission-authorized costs for utility generation-related assets and obligations have been fully recovered. The electrical

[8] SCE has agreed that this was the accepted accounting prior to AB 1890. ("... the balance in the ERAM Balancing Account includes FF&U. ..." SCE Testimony, Exh. 9, p. 24.)

> corporation shall be at risk for those costs not recovered during that time period. Each utility shall amortize its total uneconomic costs, to the extent possible, such that for each year during the transition period its recorded rate of return on the remaining uneconomic assets does not exceed its authorized rate of return for those assets. <u>For purposes of determining the extent to which the costs have been recovered, any over-collections recorded in Energy Costs Adjustment Clause and Electric Revenue Adjustment Mechanism balancing accounts, as of December 31,1996, shall be credited to the recovery of the costs.</u>" (Emphasis added.)

The language of the statute is clear. Any overcollections in the ECAC and ERAM balancing accounts <u>shall</u> be credited to the recovery of costs. The statute is mandatory; it leaves no discretion for SCE to determine whether it wishes to credit any ECAC or ERAM overcollections to ratepayers, nor to make adjustments to these accounts.

We have consistently interpreted § 368 as being mandatory. In D.96-12-077 in reference to utility plans to comply with § 368, we said:

> "Section 368 is cast in mandatory language: Each utility 'shall propose' a plan to recover costs, and the Commission 'shall authorize' the utility to recover the costs if the plan meets certain criteria."
>
> * * *
>
> "For these reasons our approval of the plans is subject to the following principles:
>
> "To the extent that any element of the plans or of this decision is inconsistent with § 368 or any other provision of AB 1890, the language of the statute prevails." (D.96-12-077, p. 4.)

When statutes are clear in their plain language, it is inappropriate for a court (or this Commission) to indulge in further statutory construction of legislative intent. (People v. Edwards 54 Cal.3d 787, 810 (1991).) In such an instance, the plain wording of the statute must be followed. (Droeger v. Friedman, et al. 54 Cal.3d 26, 38 (1991).) A court will decline to apply the plain meaning of the statute only when to do so would lead to absurd results or to frustrate the legislation as a whole. (People v. Belleu, 24 C.3d 879 (1979).)

The use of "shall" in the statute means that the Commission must order a disposition of funds in strict compliance with the statute's plain meaning. "shall" is an imperative direction. (Edison v. PUC, 51 CA3d 577, 582 (1975).)

SCE has sought to expand the one issue raised by ORA, the propriety of an ERAM adjustment, by injecting a multiplex of issues, including adjustments to ECAC, to various SONGS 2 & 3 memorandum and balancing accounts, and to a Palo Verde memorandum account. We are not here concerned with how SCE has adjusted FF&U in accounts other than the ERAM account at issue. Nor are we here concerned with how other utilities have adjusted their accounts for FF&U.[9] Our consideration is limited to the statutory construction of a sentence in § 368(a) not previously addressed.

The stakes are easily understood. SCE has overcollected gross revenues during the record period from which it paid approximately $4.1 million in franchise fees to various government entities. If FF&U is credited to ratepayers through the TCBA than SCE will not be able to recover its FF&U payment for the period in question. In juxtaposition, the ratepayers have overpaid for electricity during the record period by an amount which includes approximately $4.1 million in FF&U. Failing to receive the credit, they lose it. We must

[9] Given the statutory interpretation we believe is appropriate, we direct the Energy Division to review the accounts of all electric utilities in conformity with this decision.

determine who bears the loss. We believe that the correct statutory interpretation places the loss on SCE.

SCE does not dispute that prior to the enactment of § 368 all overcollected amounts in the ERAM account included FF&U. The entire overcollection would have been returned to ratepayers by either a reduction in rates or a credit to the ratepayer's bill. In either case, the overcollected FF&U portion of rates would be part of the amount returned. Franchise fees would be paid in the year of overcollection but would be less in the year of repayment; over the two-year period parties paid, collected, and received the correct amount.

Section 368 changed the equation. Rather than refunding the overcollection to those who had paid it, the legislature donated the money to the electric utilities to assist the utilities in recovering their uneconomic costs of generation-related assets. The question is, What did the legislature donate? In our opinion, the answer is "...<u>any</u> over-collection recorded in the ... Electric Revenue Adjustment Mechanism balancing accounts, as of December 31, 1996, ..." (§ 368(a), emphasis added.) This Commission in D.96-12-077 and D.97-11-074 extended that transfer period to 1997 for both under- and overcollections. The $4.1 million of FF&U was recorded in the ERAM balancing account during the periods at issue. SCE had no authority to make any adjustments to the account.

Our decision makes the ratepayers whole and mirrors what would have resulted had § 368 not been enacted. Prior to § 368, an overpayment in ERAM would have been refunded 100% to the ratepayers. By our decision in this proceeding, 100% of the refund is credited to ratepayers, thereby shortening the rate freeze period. SCE says that this result denies it the opportunity to recover reasonably incurred costs; but a contrary result would deny the ratepayers the opportunity to recover an overpayment of rates. The statute clearly comes down on the side of the ratepayers. SCE's shareholders also benefit from the statute. AB 1890 provided electric utilities the opportunity to recover uneconomic generating costs at a highly accelerated pace, while freezing electric rates at a level high enough to pay off the uneconomic costs.

6. Comments

Both parties submitted comments to the Proposed Decision. The comments merely restated the arguments set forth in their briefs. No changes to the Proposed Decision are warranted.

Findings of Fact

1. SCE's operation of, and expenses for, the Mohave Generating Station (Mohave) during the period of January 1, 1997 through December 31, 1997 were reasonable.

2. SCE's expenses associated with the operation of the Four Corners Generating Station (Four Corners) during the period of January 1, 1997 through December 31, 1997 were reasonable.

3. SCE's coal procurement and delivered coal prices for Mohave and Four Corners coal plant during the period of January 1, 1997 through December 31, 1997 were reasonable.

4. SCE's gas and oil generation and expenses during the period of January 1, 1997 through December 31, 1997 were reasonable.

5. SCE's natural gas procurement and gas supply management during the period of January 1, 1997 through December 31, 1997 were reasonable.

6. SCE's cost of gas purchases subject to the Gas Cost Incentive Program (GCIP) benchmark evaluation during the period of January 1, 1997 through December 31, 1997 was reasonable.

7. SCE's fuel oil inventory management during the period of January 1, 1997 through December 31, 1997 was reasonable.

8. SCE's sales of low sulfur fuel oil during the period of January 1, 1997 through December 31, 1997 were reasonable.

9. SCE's hydro generation and expenses during the period of January 1, 1997 through December 31, 1997 were reasonable.

10. SCE's Public Utility Regulatory Policies Act purchases and expenses during the period of January 1, 1997 through December 31, 1997 were reasonable.

11. SCE's administration of its long-term power purchase, exchange and sales agreements during the period of January 1, 1997 through December 31, 1997 was reasonable.

12. SCE's costs and revenues associated with transactions pursuant to its long-term power purchase, exchange and sale agreements during the period of January 1, 1997 through December 31, 1997 were reasonable.

13. SCE's economy energy transactions during the period of January 1, 1997 through December 31, 1997 were reasonable.

14. SCE's calculation of its Nuclear Unit Incentive Procedure (NUIP) amounts is reasonable. SCE should be authorized to recover NUIP rewards associated with the operation of the Palo Verde Nuclear Generating Stations as follows: Unit 2, $2,503,971; Unit 3, $1,635,474.

15. SCE should reflect the authorized NUIP amounts, plus applicable interest, in the Transition Cost Balancing Account (TCBA).

16. SCE's emission allowances trading transactions during the period of January 1, 1997 through December 31, 1997 were reasonable.

17. SCE's administration of its special rate contracts with Dow Chemical, Eisenhower Medical Center, Mobil, and UNOCAL/TOSCO during the period of January 1, 1997 through December 31, 1997 was reasonable.

18. The recorded operation of the following SCE balancing accounts during the period of January 1, 1997 through December 31, 1997 was reasonable, including the operation of the: (1) ECAC balancing account; (2) SONGS 2 & 3 incremental costs incentive pricing (ICIP) balancing account; (3) Palo Verde Nuclear Generating Station (Palo Verde) incremental costs (PVIC) balancing account; and (4) CARE balancing account.

19. SCE improperly deducted franchise fees and uncollectibles from the overcollected balances in the ERAM balancing account during the record period.

20. SCE's transfer of its ERAM balancing account to the TCBA was net of FF&U.

21. SCE should not have adjusted its ERAM balancing account and its ITCBA balances to remove FF&U prior to transferring these balances to the TCBA.

22. The amount of FF&U removed by SCE prior to transfer was $4,106,000.

23. SCE shall transfer $4,106,000 plus interest accrued at the three-month commercial paper rate from January 1, 1998, to the TCBA.

24. SCE's operations during the period of January 1, 1998 through March 31, [illegible] were reasonable, except for the transfer of the ERAM balancing [illegible] the TCBA.

25. SCE's costs recorded in the ISP/PX Implementation Delay Account from January 1, 1998, through March 31, 1998 were reasonable. Accordingly, SCE should be authorized to recover the costs recorded therein.

26. SCE's administration of its special rate contracts with Dow Chemical, Eisenhower Medical Center, Mobil, and TOSCO during the period of January 1, 1998 through March 31, 1998 was reasonable.

27. SCE's EV programs were reasonably implemented and administered, and the costs incurred during the period of January 1, 1998, through April 30, 1998 were reasonable.

Conclusions of Law

1. In § 368, the word "shall" is mandatory.

2. The language of § 368(a) applies to overcollections in ERAM in 1997 as well as 1996. (D.96-12-077, mimeo., p. 7.)

ORDER

IT IS ORDERED that:

1. Southern California Edison Company (SCE) is authorized to recover Nuclear Unit Incentive Procedure (NUIP) rewards associated with the operation of the Palo Verde Nuclear Generating Stations as follows: Unit 2, $2,503,971; Unit 3, $1,635,474.

2. SCE should reflect the authorized NUIP amounts, plus applicable interest, in the Transition Cost Balancing Account (TCBA).

3. SCE is authorized to recover the costs recorded in the Independent System Operator/Power Exchange Implementation Delay Account from January 1, 1998, through March 31, 1998.

4. SCE shall forthwith transfer $4,106,000 plus interest accrued at the three-month commercial paper rate from January 1, 1998 to date of transfer, to the TCBA.

5. This proceeding is closed.

This order is effective today.

Dated November 4, 1999, at San Francisco, California.

RICHARD A. BILAS
President
HENRY M. DUQUE
JOSIAH L. NEEPER
JOEL Z. HYATT
CARL W. WOOD
Commissioners