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Decision 91-09-024 September 6, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of Sierra Pacific Power Company for authority to implement its Energy Cost Adjustment Clause (ECAC), its Electric Revenue Adjustment Mechanism (ERAM), and its Low-Income Rate Assistance (LIRA) surcharge.	Application 90-08-068 (Filed August 29, 1990)

<u>David M. Norris</u>, Attorney at Law, for Sierra Pacific Power Company, applicant.
<u>Alberto Guerrero</u>, Attorney at Law, David Weiss and Geoffrey Meloche, for Division of Ratepayer Advocates.

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O P I N I O N

Summary

In this decision Sierra Pacific Power Company (Sierra) is authorized a net reduction in rates of $3,039,000, or 8.46% annually. This reduction is comprised of a decrease of $1,938,000 in Sierra's Energy Cost Adjustment Clause (ECAC) balance, an increase of $36,000 in the Annual Energy Rate, a decrease of $1,222,000 in Sierra's Electric Revenue Adjustment Mechanism (ERAM), and an increase of $85,000 in its Low Income Rate Assistance (LIRA) revenue requirement.

Procedural Background

Sierra filed its application on August 8, 1990, and the matter first appeared on the Commission's Daily Calendar on September 11, 1990. Public notice of the hearing was made pursuant to Rule 52 in February, 1991.[1] A prehearing conference was convened on October 15, 1990 and continued as a telephone conference on December 17, 1990 and March 4, 1991. Hearing was held on March 14 and 16 in San Francisco with Sierra and the Division of Ratepayer Advocates (DRA) as the only parties. At the parties' request the reasonableness and forecast phases of this proceeding were joined for hearing in departure from the Commission's Rate Case Plan.

Section 311 Comments

On July 10, 1991, the Administrative Law Judge's (ALJ) proposed decision was mailed to all parties for comments, pursuant to Rule 77.1 of the Commission's Rules of Practice and Procedure. Timely filed comments were received from Sierra and DRA. No reply comments were filed. We have reviewed the comments pursuant to

1 Proof of notice pursuant to Rule 52 appears in the record as Exhibit 1.

Rule 77.3, and our order incorporates minor revisions for clarification.

Uncontested Issues

No contested issues appeared in the pleadings as to Sierra's proposed ERAM and Annual Energy Rate (AER) reductions and LIRA implementation rate of $228,000. During the hearing, Sierra and DRA reached agreement on the issues of revenue allocation methodology (Exhibit 17) and the North Valmy coal plant thermal performance standard (TPS) (Late Filed Exhibit 15). In addition, DRA withdrew its proposed adjustment of $23,385 to the ECAC balancing account in connection with a monthly refund to Sierra from Utah Power and Light, and Sierra accepted a reduction in the ECAC balancing account of $97,586 to correct the error in the recording of economy energy sales to off-system customers (Exhibit 19).

In its Forecast Report, DRA accepted Sierra's proposal for revenue allocation using the System Average Percent Change (SAPC) method for this ECAC, but recommended that Sierra allocate revenues in its next ECAC using 100% of Equal Percentage of Marginal Costs (EPMC). At the hearing, the parties jointly proposed a revenue allocation methodology covering Sierra's future ECAC proceedings as set forth in Exhibit 17. The Commission adopted the EPMC method for Sierra in Sierra's last combined General Rate Case (GRC)/ECAC decision (Decision (D.) 90-07-060), pursuant to stipulation between DRA and Sierra. Under the proposed agreement, attached as Appendix B, Sierra would: (1) use a modified EPMC method in its 1991 ECAC filing; (2) use the SAPC method in its 1992 ECAC filing to be changed to EPMC when a decision is issued in Sierra's Test Year (TY) 1993 GRC; (3) use a modified EPMC in its 1993 ECAC based on the marginal cost study in the TY 1993 GRC; and (4) in its 1994 ECAC filing use EPMC with modifications only to reflect the 1994 ECAC customer and sales forecasts. The 1992-94 cycle would be followed for ECACs following GRCs in the future.

The TPS issue had been a matter of some controversy in Sierra's 1989 ECAC proceeding. DRA questioned Sierra's calculations of the thermal efficiency of the North Valmy coal-fired generation plant.[2] A disagreement arose over the proper methodology to be followed in calculating the thermal efficiency of the plant, leading the Commission to order the parties to "pursue a cooperative effort" to develop an acceptable TPS by which the operation of the plant could be evaluated (D.89-07-018).

Pursuant to the Commission's orders in the 1990 ECAC decision, the parties prepared engineering reports analyzing the problem in great detail. Following negotiations held concurrently with the hearing, Sierra and DRA jointly sponsored Late-Filed Exhibit 15 containing the recommendations on which the parties agreed. As set forth in the exhibit, a TPS is proposed which is based on a statistical analysis of the plant's historical operation between 1985 and 1990. The data used in this approach was Sierra's monthly deviations between the adjusted actual and theoretical heat rates. This approach allows for implicit consideration of the uncertainties of measurement inherent in coal-fired generators. From this, a two-part scale was established which encompasses the range of acceptable thermal performance of the plant. Range A of the scale covers the mean historical heat rate and one standard deviation above and below the mean.[3] A second range, designated

2 It appeared that the plant was at times operating at efficiencies, as measured by the heat rate, which were greater than the engineering specifications of the plant would theoretically allow. "Heat rate" is the energy in Btu's required to generate one net kilowatt-hour of electricity.

3 A standard deviation is a statistical expression for the probability that a value, in this case the measured heat rate, will fall within a defined distance from the mean of all values.

Range B, would span all measured heat rate values between one and two standard deviations below the mean.

Under the proposed agreement, heat rate results which fall within Range A would support a rebuttable presumption of reasonable operation. Results above the upper end of Range A would indicate that the plant consumed more fuel than necessary for efficient operations. Heat rate results in Range B would indicate that the plant is operating at greater efficiency than might be theoretically expected. No presumption of unreasonableness would arise, however, because performance in Range B could be the result of actual efficiency improvements or of measurement uncertainty or even a combination of both. Sierra would be required to thoroughly explain any performance falling within Range B. Performance in Range B for a period of two consecutive years would indicate that the plant's theoretical heat rates should be modified based on input/output tests. Any performance above the upper limit of Range A or below the lower limit of Range B would give rise to rebuttable presumption that the operation of the plant was unreasonable.

Contested Issues

In the course of the hearing, the parties identified two contested issues in the reasonableness portion of this proceeding and disagreed as to fuel inventories and hydroelectric generation in the forecast phase. Each issue is presented below with a separate discussion immediately following.

The Reasonableness of the Gas Research Institute Fee

In its Audit Report (Exhibit 12), DRA recommended that the ECAC account be credited $19,818 in order to remove Sierra's contribution to the Gas Research Institute (GRI) from the balancing account. Sierra included this expense because it was an item in Northwest Pipeline Company's (Northwest) billing for gas transportation service purchased by Sierra. Northwest includes a charge for the GRI fees in its Rate Schedule TI.1. The GRI fee is determined on the basis of a GRI assessment times the quantity of gas transported for the customers.

DRA argued that the GRI fee is a contribution to research and development. As such, the fee is not a direct fuel cost and should be recovered as a cost item in Sierra's GRC.

Discussion

DRA correctly argues that the funds collected by GRI are put to research purposes. All utilities who are members of the Institute pay dues to support a collective research program. Northwest recovers its membership costs in tariff rates based on the volume of gas transported to its customers. The proper test for inclusion in an ECAC account is whether the cost is related to fuel or energy. In the case of a fuel purchase, how the seller disposes of the proceeds is not relevant. Since Sierra incurs this cost only when it acquires fuel and in an amount determined by the amount of fuel transported, the GRI assessment is a direct component of Sierra's cost of fuel. That Northwest uses the revenue for the promotion of gas research does not overshadow the fact that Sierra incurs the fee as a cost of gas transportation.

We conclude that the payment by Sierra of the $19,818 GRI assessment is a direct variable fuel cost and should not be credited to the balancing account as DRA requests. Sierra should be allowed to continue to include this fee in its ECAC so long as it continues to incur the cost as a component of the price of fuel.

The Reasonableness of the Transfer Price of Long-Term Gas

Gas is delivered to Sierra's Fort Churchill and Tracy power plants over the Northwest and Paiute pipeline systems. This gas is purchased by Sierra's affiliate, Westpac Utilities, the local gas distribution service for the Reno area. Westpac purchases both long- and short-term gas supplies and makes some of the long-term gas available to Sierra. Sierra is not required to take any of Westpac's purchases. Long-term gas not required by Westpac is transferred to Sierra at a price which is established as the lesser of the "Inside the Federal Energy Regulatory Commission (FERC) Gas Market Report" average price or the highest priced spot market bid accepted by Sierra. The difference between the transfer price paid by Sierra for its California service and the commodity portion of the rate paid by Westpac during the record period was $17,111.

DRA believes that the price to Sierra should be set at the commodity price paid by Westpac for long-term gas. According to DRA, the portion of gas made available to Sierra is "interruptable" by Westpac, so Sierra's customers should not pay any portion of the demand charges Westpac incurs. DRA argues that once Westpac has paid its demand costs, the gas used by Sierra reflects only incremental demand.

Sierra argues that its California customers should not be the beneficiaries of a subsidy provided by Westpac. Sierra maintains that it would not be able to obtain a price for gas as low as Westpac's commodity-only price on the spot market. Sierra and Westpac set the long-term transfer price at the spot market price to reflect the fact that if Westpac were not available, Sierra's best recourse, in theory, would be to spot gas. Sierra believes that this approach avoids any subsidy flowing in either direction between Sierra and its affiliate. Sierra claims that since the transaction between Sierra and Westpac is an ordinary gas purchase, at a minimum, the seller should receive a price sufficient to recover its costs. To expect Westpac to refrain from attempting to recover at least some of its own demand costs from Sierra is unreasonable in Sierra's view because it would result in a subsidy to Sierra at the expense of Westpac customers.

Sierra points out that even under this "indifference" pricing approach, Sierra's customers benefit from the fact that spot gas is curtailable due to general market conditions while Westpac gas is curtailable only when conditions in Westpac's service area require. Therefore, it is somewhat less likely that Sierra would have to resort to expensive fuel burns. The inclusion of Sierra's incremental demand in purchases made by Westpac may also result in some gas purchases being more economical due to the combined purchase power of the two companies. Sierra believes that if the prices paid to Westpac do not include some contribution to Westpac's demand costs for long-term supplies, Westpac would have no economic incentive to sell the gas to Sierra.

Discussion

We agree with Sierra to the extent that its electric customers should not be subsidized by Sierra's affiliate gas distribution company. We also agree with DRA that Sierra's customers should not be charged more than Sierra's actual costs for fuel. Accordingly, we think that Sierra and Westpac should fix a price for these gas transfers that will compensate Westpac for those costs it actually incurs in supplying Sierra with fuel. We are not certain, however, that the present pricing approach meets that objective.

The present price is based on the price Sierra would likely pay in the absence of Westpac as its gas purchaser. In effect, this is value pricing based on the next best alternative, the spot market. The approach is sensible to a degree, but it ignores the reality that the opportunity to purchase gas from Westpac is there. It would be just as unreasonable for any utility to ignore a convenient opportunity to reduce its fuel costs as it would be to require an affiliate of a utility to confer benefits on utility customers without compensation. We think a better approach would be to establish a price based on the actual costs Westpac incurs in supplying Sierra, with the likely costs Sierra would incur if Westpac did not exist used as a reasonableness check.

This would require a showing that the parties have not undertaken to make in this proceeding, but we believe it is one that not only should be made but can be made in Sierra's forthcoming ECACs. We will require Sierra to develop a methodology for apportioning the actual costs of Westpac's long-term gas supplies between Sierra's and Westpac's customers based more closely on the actual costs Westpac incurs on Sierra's behalf.

We need not lay out in this decision a specific methodology for Sierra to follow. In the absence of actual cost based pricing, Westpac's long-term gas transfers will continue to be subject to the argument that Sierra is taking advantage of the differential between Westpac's commodity price paid and the spot market because an affiliate relationship exists. Conversely, to disallow all demand costs for Westpac gas in Sierra's ECAC rates might permit Sierra's California customers to take advantage of the affiliate relationship without compensating Westpac's customers. Neither result would be a just one.

We think that the Westpac-Sierra affiliate relationship presents an opportunity to benefit both customer groups. That relationship, however, is a delicate one which calls for extra effort to prevent the distribution of these benefits from tilting into cross-subsidy. That peril may be avoided by meticulous auditing and full disclosure. When Sierra discloses clearly the actual flow of costs and benefits, without resort to hypothetical proxies such as its current pricing mechanism, our concern over the potential subsidy will be dispelled.

In the meantime, Sierra has not borne its burden of proof in this proceeding that the spot market-based pricing it used actually reflects the true and reasonable cost incurred by Westpac in supplying Sierra with gas. Accordingly, Sierra will be allowed to recover only the Westpac commodity rate in this ECAC.

Forecast Hydroelectric Generation

In its application, Sierra based its forecast hydroelectric generation for the 1991 forecast period on an assumption of reduced streamflows due to continuing drought conditions. The result was an estimate of 59,654 MWh for the forecast period. DRA based its estimate of 61,291 MWh on an assumed normal precipitation year. In the months following Sierra's August 8, 1990 filing, Sierra grew even more apprehensive about the loss of hydroelectric capacity as the drought continued through the early winter period. At the hearing, Sierra revised its forecast downward to 25,800 MWh based on Sierra's actual hydrogeneration during calendar year 1990.[4]

DRA criticizes Sierra's forecast as assuming extra-normal rainfall conditions in violation of Commission policy set forth in D.85731. DRA focuses exclusively on that segment of D.85731 which pointed out that 12-month weather forecasts are inaccurate and unreliable. DRA contends that Sierra's assumption that drought conditions will prevail over the forecast period is in error because it is the result of an attempt to forecast the weather over the 12-month forecast period. DRA claims that the hydroelectric forecast should be based on average rainfall regardless of the present weather trend.

Sierra claims that it bases its estimate, not on weather forecasts, but on an extrapolation of known hydrological

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4 The use of a calendar year does not correspond properly to the forecast period which in Sierra's case is April 1 to March 31.

conditions. Sierra says that groundwater levels are so low, as the result of five years of drought, that even if rainfall in the forecast period exceeded 200 percent of normal, there would still not be sufficient runoff to reach DRA's estimate.[5] Sierra points out that its Lahonton and 26' drop hydro plants depend entirely upon stream flows in the Truckee River originating from Lake Tahoe. Sierra testified that, as of the date of hearing, no water was flowing from the lake because the lake level had dropped below the elevation of the dam which controls the discharge of lake water into the Truckee River. The lake level is expected to drop another six feet during the summer due to evaporation. Sierra claims that its actual total hydroelectric generation has been below 50,000 MWh since 1984, and that hydroelectric generation for the present reasonableness review period was only 41,000 MWh.

Discussion

In light of the evidence presented by Sierra, we find it unreasonable to expect that Sierra will generate 61,291 MWh of hydroelectric power during the forecast period. We need neither a perfect weather forecast nor a crystal ball to note that the state as a whole is experiencing a long-term shortage of water. While we do not simply assume that drought conditions will continue, we believe Sierra has presented substantial evidence that under any reasonable weather scenario, Sierra will almost certainly not experience normal stream flows during a substantial portion of the forecast period.

We recognize that there are risks in using average year temperatures and precipitation as an input in energy forecasts, but at the same time, all forecasts are subject to some error. In

5 Sierra's testimony is based on the observation of its management; no technical groundwater or snow-pack surveys were undertaken.

D.89-12-015 (PG&E's ECAC application, A.89-04-001), we allowed the use of average year forecasts to be "tempered by existing conditions" such as PG&E's snow-pack surveys. In that case, we noted as well that snow-pack surveys performed in June are relevant even though a forecast period might enclose an entirely different winter season because a prior season late snow-pack may influence runoff for a portion of the succeeding forecast period (p. 42 and Findings of Fact 88, 89, 90, and 91). In that decision, we also cautioned that consistency should be maintained in order to avoid the situation where ECAC parties "might be tempted to select such existing conditions as would be most favorable to each party's case."

Sierra did not present a snow-pack survey in its present application. Nevertheless, we do not believe that snow-pack studies are the only factor that can be used to temper average year forecasts. Sierra did testify that its hydroelectric generating capacity is entirely dependent on streamflows in the Truckee River, which in turn are governed by the level of Lake Tahoe. The condition of the lake, according to Sierra, is such that precipitation at twice the normal rate would still not bring streamflows up to the level of a normal runoff year. We believe the average year forecast is therefore of considerably less use this year and should be tempered with consideration of the level of Lake Tahoe. We will accept Sierra's original drought year forecast of 59,654 MWh for the forecast period. This approach acknowledges the ongoing effects of drought without assuming, as Sierra does, that runoff will be the same between April 1, 1991 and March 31, 1992 as between January 1, 1990 and December 31, 1990. In the absence of more reliable data such as snow-pack surveys on a consistent basis or a complete quantitative analysis of the relationship between lake levels and stream flows in the Truckee River, we will only "temper" the average year precipitation forecast to this degree.

Forecast Fuel Inventories

Sierra and DRA disagree sharply as to the appropriate inventories of coal, residual oil, and diesel fuel to be maintained during the forecast period. The table below summarizes the parties' recommendations with a comparison of the 1989-1990 actual inventories and the most recently authorized levels for residual oil and diesel.

Comparison of Fuel Inventories

	Coal Tons	Residual Oil Bbl.	Diesel Bbl.
1989 Authorized	NA	263,904	4,518
Actual Recorded		272,184	5,167
Sierra 1990 Forecast	139,461	281,964	5,656
DRA 1990 Forecast	94,689	255,205	4,971

The dispute over fuel inventories is animated by Sierra's desire to guard against fuel outages due to limited storage capacities and geographic remoteness and by DRA's desire to keep inventory carrying costs down. Sierra's higher inventory levels are not based on the use of a specific methodology. Instead Sierra relies on historical trends amplified by its assessment of the potential for wide fluctuations in seasonal demand due to the climate of its service area and the difficulties involved in transporting the various fuels to Sierra's power plants. DRA, on the other hand, does not explicitly address the theoretical potential for serious supply interruptions but uses historical data showing the two-year trend of monthly fuel consumption to derive a monthly average inventory for the forecast period weighted to reflect seasonal changes in fuel use.[6]

6 DRA departs from its methodology in a portion of its diesel fuel inventory forecast as discussed infra.

In the case of the coal inventory, Sierra believes a 60-day average supply must be maintained in light of the risks that Idaho Power Company, Sierra's partner in the Valmy coal plant, might unpredictably bring about a sudden draw-down of the coal inventory. Sierra believes this contingency is made even more threatening by the difficulties of scheduling an additional coal supply train to meet such a contingency.

Sierra's desired 13-day average supply of residual oil is based on its management policy of maintaining a full inventory of 18 days reserve in winter and eight days in summer in anticipation of winter gas curtailments. Sierra wishes to be able to purchase large inventories during the late summer while prices are generally lower to hold for use during the winter. Sierra seeks specific authority from the Commission to retain all excess winter oil reserves, arguing that such is the cost of insuring service continuity. DRA's forecast methodology produces a recommended average oil inventory of 11.5 days. DRA objects to Sierra's approach, arguing that if oil burns do not actually materialize, then Sierra is forced to choose between uneconomically burning down the winter reserve or maintaining a high oil inventory beyond the winter period in which gas supply curtailments are most likely and the delivery of alternate fuels is made more difficult.

Sierra and DRA have similar differences over the forecast diesel inventory. Sierra bases its estimate on the adjusted actual use of diesel oil during the 1989-1990 record period. DRA, however, does not use its contingency methodology for Sierra's gas plants at Kings Beach, Portola, and Tracy. Instead, DRA adopts Sierra's recommended inventory level for summer only for these three facilities. The result is that DRA's <u>total</u> diesel inventory forecast is 1,955 barrels lower than Sierra's. Sierra claims that if DRA had used its methodology consistently, DRA's total would have been 6,067 barrels. This figure would exceed Sierra's total inventory by (6,067 - 5,656) 411 barrels.

Discussion

While we fully agree with Sierra's concern for avoiding power outages, we think that, overall, DRA's methodology more adequately reflects the likelihood that serious fuel supply disruptions will actually materialize. Sierra, for example, desires a 60-day coal stockpile to ward against combined impact of Idaho Power consuming its share of Valmy coal at a time when winter weather or economic conditions could make a second coal train delivery unavailable. While Sierra's scenario is certainly possible, little evidence was shown to demonstrate the likelihood of such events occurring. DRA, on the other hand, presented a historical analysis of coal train deliveries over the past five years. DRA's analysis shows that delays in securing a second train average 1.8 days, with the longest delay since November 1985 being 7.5 days (Exhibit 10). DRA testified that a review of Sierra's monthly coal train records shows that even during the winter months of increased weather related risk, Sierra received 98.2% of orders placed.

DRA's method of averaging the worst case actual monthly usage during summer and a 60-day supply for the months of November through March produces a reasonable inventory and leaves Sierra free to manage the inventory on a month-to-month basis. This approach is superior because it reflects Sierra's actual rather than potential coal inventory needs.

The same general reasoning leads us to adopt DRA's forecast residual oil inventory over Sierra's proposal. We agree with DRA that the primary function of the residual oil inventory is to "buy time" during curtailments to arrange for alternative gas deliveries or for the shipment of additional oil when needed. DRA points out that Sierra can obtain oil deliveries within 5 days and argues that its 11.5-day recommendation based on historical oil use adjusted for contingencies comfortably covers that time period. Any advantage in purchasing lower priced oil in summer could be reduced by the need to retain it in the following spring if curtailments do not materialize.[7]

Turning to the question of the diesel fuel inventory forecast, DRA has not satisfactorily explained why it abandoned its methodology in regard to the Kings Beach, Portola, and Tracy plants and chose instead an inventory level which ignores winter diesel consumption altogether.[8] Without an explanation of why the methodology was not used, we are reluctant to apply it across-the-board to Sierra's diesel inventory. We will, instead, adopt Sierra's diesel forecast for these three plants. This figure reflects the winter diesel demand, at least as Sierra views it, while DRA's recommendation would have us only provide for diesel reserve that Sierra desires for the summer months.

Review of Valmy Economy Energy Purchases

In its audit report (Exhibit 12), DRA asserted its "right" to review and to "make disallowances of expenses" related to purchases of economy energy from Idaho Power Company in next year's ECAC proceeding. On cross-examination, DRA specified its concern is directed to further field audit of shared North Valmy operation and maintenance (O&M) expenses (TR 1:88, Jimenez/DRA). Sierra opposed this assertion, arguing that DRA has no right to defer its recommendation to a future proceeding.

Since DRA did not challenge the Valmy purchases in this proceeding, we will accept Sierra's request for their recovery. DRA's right to propose adjustments in the next ECAC based on further investigation of shared O&M expenses in this period is

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7 Sierra's approach would merely exchange the risk of curtailment for the risk of inventory over-stock.

8 At the hearing, DRA testified that its diesel forecast is derived by way of the methodology adopted by the Commission in D.89-07-018. The methodology adopted there, however, was the very same which DRA declines to use for King's Beach, Portola, and Tracy in this proceeding.

retained, based upon the fact that DRA has specifically identified the need to further audit these expenses and has taken affirmative steps in this proceeding to preserve the issue.

__Ruling on Motions to Strike__

Following DRA's direct testimony in the hearing, Sierra offered the rebuttal testimony of Randy G. Harris (Exhibit 21) addressing the forecast issues of fuel inventory and hydroelectric generation. DRA made oral motions to strike three segments of the witness' testimony. The ALJ reserved his ruling on the motions for inclusion in the proposed decision.

In its first motion to strike, DRA sought to exclude testimony concerning the coal transportation difficulties Sierra has encountered since 1989, the prospect for decreased rail car availability in 1991 and a description of several factors which can cause delays in obtaining a second coal train in the event one is needed during the forecast period. The basis of DRA's motion was that this testimony went beyond the scope of rebuttal to DRA's direct testimony. Counsel for DRA argued that the testimony was, in fact, additional direct testimony unrelated to the direct testimony of DRA's witness.

DRA's motion cannot be granted. DRA's prefiled testimony (Exhibit 10) discussed DRA's own analysis of coal train delays due to freezing weather conditions, mine and railroad labor disputes, and transportation problems as never having caused any significant delays (Exhibit 10, pp. 6-7 to 6-11). The thrust of Sierra's rebuttal was the attempt to lessen the impact of DRA's performance-based analysis over the past five years by demonstrating that such events have been narrowly avoided in the past and that some likelihood exists that they might yet occur. Although this segment of Sierra's rebuttal testimony is somewhat speculative, it is clearly within the scope of rebuttal.

DRA's second motion to strike concerned Sierra's rebuttal testimony in reference to surveys of coal inventories of several coal-fired power utilities in other states (Exhibit 21, question and answer 32 and 33). One survey was undertaken by the City of Colorado Springs in 1988 and the other in 1989 by the Idaho Power Company. DRA's motion is granted. DRA introduced no evidence in its direct testimony on the issue of the comparability of Sierra's proposed 60-day inventory to the inventories of other utilities.

DRA's final motion sought to strike that segment of Sierra's rebuttal testimony showing that Sierra had made the same request for approval of a 60-day coal inventory in its 1985 GRC and 1989 ECAC proceedings. In both earlier proceedings, according to Sierra's witness, DRA did not contest the proposal. DRA's objection was based on lack of relevance and on the fact that the coal inventory issue was settled by stipulation of the parties. DRA's motion to strike is granted on both grounds. That Sierra proposed a certain coal inventory in its prior GRC is not relevant to an ECAC proceeding held 5 years later. The question at hand in this proceeding is whether or not a 60-day coal inventory is a reasonable level for the 1991 forecast period. That Sierra or even DRA believed that level was appropriate in 1985 has no bearing on the question today and is of no probative value. Testimony that DRA stipulated to a 60-day inventory in Sierra's last ECAC is made inadmissible by DRA's motion pursuant to Rule 51.9 of the Commission's Rules of Practice and Procedure.

Conclusion

A summary of the calculation of the ECAC, AER, ERAM, and LIRA rates is shown in Appendix A together with the rates proposed separately by DRA and Sierra and those items upon which the parties agree. The column headed "ADOPTED" shows the calculations made pursuant to this decision.

Findings of Fact

1. With the exception of expenditures during the 1989-90 reasonableness review period of $19,818 paid to Northwest Pipelines and $17,111 paid to Westpac Utilities, Sierra and DRA believe that Sierra's fuel related expenses were reasonable.

2. A TPS is a tool which establishes a measure of the expected operating efficiency of a generating system, commonly expressed in terms of heat rate.

3. DRA and Sierra recommend a TPS based on historical data. For the historical period of July 1985 through June 1990, monthly system deviations (differences) between the adjusted actual and theoretical heat rates have been calculated. In addition, the mean and standard deviation of these monthly differences were calculated.

4. The mean and standard deviation are the bases for the recommended TPS. Using these two values, two ranges are established: Range A and Range B.

5. Range A is defined to include those values from the mean minus one standard deviation to the mean plus one standard deviation. Numerically, Range A is -0.5% to +5%.

6. Range B is defined to include those values from the mean minus one standard deviation to the mean minus two standard deviations. Numerically, Range B is -3% to -0.5%

7. A reported annual system operation in Range A indicates rebuttable reasonable thermal operation. Operation in Range B would require additional justification by Sierra but would not necessarily indicate unreasonable operation.

8. System operation above Range A or below Range B would indicate rebuttable presumption on unreasonable operation.

9. Sierra and DRA agree that the Commission should approve Sierra's use of the SAPC method of revenue allocation in this ECAC proceeding.

10. The parties proposed a schedule for the use of the SAPC and EPMC method of revenue allocation in future ECAC proceedings.

11. Sierra is assessed a charge under the tariff of Northwest Pipeline Company for Northwest's contribution to the GRI.

12. The GRI fee is a direct variable cost of fuel to Sierra.

13. Westpac Utilities is the local gas distribution company for the Reno area.

14. Westpac is an affiliate of Sierra.

15. Westpac purchases long-term gas delivered over the Northwest and Paiute pipeline companies.

16. Long-term gas not required by Westpac is transferred to Sierra for use in Sierra's Fort Churchill and Tracy power plants.

17. The transfer price for Westpac gas was set at the lesser of either the average price of gas in the "Inside the FERC Gas Market Report" or the highest spot market bid accepted by Sierra.

18. The transfer price exceeded the commodity price paid by Westpac for long-term gas by Westpac during the record period by $17,111.

19. The transfer price was not shown to represent Westpac's actual costs in supplying Sierra with long-term gas.

20. Sierra's hydroelectric plants depend on the volume of streamflow in the Truckee River.

21. Sierra based its forecast of hydroelectric generation on Truckee River flow figures for calendar 1990.

22. Sierra's forecast hydroelectric generation does not correspond to Sierra's April 1 - March 31 ECAC forecast period.

23. The low lake level in Lake Tahoe and drought conditions in the Truckee River watershed indicate below normal streamflows during the forecast period even if precipitation is higher than average.

24. DRA's recommended average coal inventory of 41.5 days is based on a study of actual coal delivery times over the past five years.

25. An average inventory of 41.5 days is sufficient to cover the average recorded delivery delay of 1.8 days.

26. Sierra's recommended residual oil inventory of 13-day supply leverages the opportunity to purchase maximum inventories

while summer demand is low, against the risk of retaining excess inventory beyond the winter curtailment period.

27. DRA's recommended average residual oil inventory of 11.5 days is based on actual historical use and peak consumption patterns.

28. DRA did not use an average-use plus worst-case methodology for Sierra's diesel inventory at Sierra's Kings Beach, Portola, and Tracy power plants.

29. Sierra proposed a diesel inventory for the Kings Beach, Portola, and Tracy power plants based on Sierra's desired winter and summer storage levels.

<u>Conclusions of Law</u>

1. With the exception of $17,111 expended for the transfer to Sierra of gas purchased by Westpac Utilities, Sierra's expenditures for fuel during the period July 1, 1989 to June 30, 1990 were reasonable.

2. The 1991 ECAC, ERAM, AER, and LIRA rates as shown in Appendix A to this decision are reasonable and should be adopted.

3. The stipulated agreement of DRA and Sierra proposing a TPS for the Valmy coal-fired generation plant as set forth in late-filed Exhibit 15 should be adopted.

4. The schedule agreed upon by DRA and Sierra for the use of revenue allocation methodologies as set forth in Exhibit 17 should be adopted.

5. Sierra properly included the charge assessed by Northwest Pipeline Company for the Gas Research Institute in its ECAC balancing account.

6. Sierra should not be allowed to recover costs for long-term gas transfers of Westpac gas which exceed the actual costs incurred by Westpac for the gas which is transferred.

7. It is reasonable to temper Sierra's hydroelectric generation forecast with facts relating to the level of Lake Tahoe and drought conditions in the Truckee River watershed.

8. Sierra's initial filing drought year hydroelectric generation forecast of 59,654 MWh is reasonable.

9. DRA's recommended forecast average coal inventory of 41.5 days is reasonable.

10. DRA's recommended forecast average residual oil inventory of 11.5 days is reasonable.

11. DRA's recommended forecast average diesel inventory is reasonable except for the diesel inventories of the Kings Beach, Portola, and Tracy GT plants.

12. Sierra's desired average diesel inventory for the Kings Beach, Portola, and Tracy GT plants should be adopted.

O R D E R

IT IS ORDERED that:

1. Sierra Pacific Power Company (Sierra) is authorized a net revenue decrease of $3,039,000 annually or 8.46%, based on an Energy Cost Adjustment Clause (ECAC) decrease of $1,938,000, an Annual Energy Rate increase of $36,000, a decrease of $1,222,000 in Sierra's Electric Revenue Adjustment Mechanism and an increase of $85,000 in its Low Income Rate Assistance revenue requirement.

2. Sierra's fuel and purchased power transactions and related operations for the review period of July 1, 1989, through June 30, 1990, are found to be reasonable with the exception of $17,111 paid by Sierra to Westpac Utilities.

3. The stipulation entered into by Sierra and the Division of Ratepayer Advocates (DRA) for a thermal performance standard for the Valmy coal-fired generation plant as set forth herein and in Exhibit 15 in this proceeding is adopted.

4. The stipulation entered into by Sierra and DRA for a schedule of revenue allocation methodologies for future ECAC proceedings, attached as Appendix B, is adopted.

5. Projected operations for the 1990 forecast period are adopted as set forth in Appendix A to this decision.

6. Within 5 days from the effective date of this order, Sierra shall file revised tariffs, in compliance with General Order 96-A, to be effective September 15, 1991.

This order is effective today.

Dated September 6, 1991, at San Francisco, California.

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

I abstain.

/s/ G. MITCHELL WILK
Commissioner

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

COMPARATIVE EXHIBIT NO. 22
SIERRA PACIFIC POWER COMPANY
REVENUE IMPACT
APPLICATION NO. 90-08-068

LINE NO.		SIERRA	DRA	SIERRA > DRA DIFFERENCE $	%	ADOPTED
4	RATES (MILLS) (1)					
5	ECAC OFFSET RATE (2)	23.27	23.13	0.14	0.61%	23.14
6	BALANCING RATE (3)	(3.00)	(3.04)	0.04	-1.32%	(3.04)
8	ECAC BILLING FACTOR	20.27	20.09	0.18	0.90%	20.10
10	AER RATE (2)	6.56	6.52	0.04	0.61%	6.53
12	ERAM RATE	(4.97)	(4.97)	0.00	0.00%	(4.97)
14	LIRA RATE	0.52	0.52	0.00	0.00%	0.52
17	CALIFORNIA JURISDICTIONAL SALES (MWH)	447,613	447,613	0	0.00%	447,613
19	REVENUE REQUIREMENT ($000)					
20	ECAC OFFSET (LN 5 X LN 17)	$10,416	$10,353	$63	0.61%	10,358
21	ECAC BALANCING	(1,343)	(1,361)	18	-1.32%	(1,361)
23	TOTAL ECAC	9,073	8,992	81	0.90%	8,997
24	AER (LN 10 x LN 17)	2,936	2,918	18	0.62%	2,923
26	SUBTOTAL - ECAC	12,009	11,910	99	0.83%	11,920
27	ERAM	(2,225)	(2,225)	0	0.00%	(2,225)
28	LIRA	228	228	0	0.00%	228
30	TOTAL REVENUE REQUIREMENT	10,012	9,913	99	1.00%	9,923
32	TOTAL REVENUE REQUIREMENT AT PRESENT RATES	12,960	12,960	0	0.00%	12,962
34	INCREASE (DECREASE) (LN 30 - LN 32)	$(2,948)	($3,047)	$99	-3.25%	(3,039)
38	TOTAL REVENUE AT PRESENT RATES	$35,902	$35,902			35,902
40	INCREASE (DECREASE) AS % OF TOTAL	-8.21%	-8.49%			-8.46%

43 (1) OII 90-08-006 SUSPENDS, BUT DOES NOT ABOLISH, THE AER MECHANISM. THEREFORE, RATES
44 REFLECT THE APPLICABLE ECAC AND AER PERCENTAGES. UNTIL FURTHER ORDER OF THE COMMISSION
45 BOTH THE ECAC AND AER WILL RECEIVE FULL BALANCING ACCOUNT TREATMENT.
46 (2) DIFFERENCE RESULTS FROM SIERRA'S LOWER HYDRO FORECAST AND HIGHER AVERAGE INVENTORY
47 LEVELS. SEE PAGES 2 AND 3.
48 (3) DIFFERENCE RESULTS FROM DRA'S AUDIT ADJUSTMENT FOR LONG-TERM GAS TRANSFER PRICING.

APPENDIX A
Page 2

COMPARATIVE EXHIBIT NO. 22
SIERRA PACIFIC POWER COMPANY
CALCULATION OF ECAC RATE
APPLICATION NO. 90-08-068
($000)

LINE NO.		SIERRA	DRA	SIERRA > DRA DIFFERENCE $	%	ADOPTED
1	FUEL COSTS					
2	COAL/DIESEL	$37,251	$37,071	$180	0.49%	36,951
3	RESIDUAL OIL	862	619	243	39.26%	864
4	NATURAL GAS	32,322	32,272	50	0.15%	32,422
5	NATURAL GAS SERVICE CHARGE	6	6	0	0.00%	6
6	DIESEL OIL	156	156	0	0.00%	156
7	FUEL HANDLING	1,112	1,112	0	0.00%	1,112
8						
9	TOTAL FUEL COSTS	71,709	71,236	473	0.66%	71,511
10						
11	PURCHASED POWER COSTS					
12	IPCO - ELKO	2,333	2,333	0	0.00%	2,333
13	PG&E	186	186	0	0.00%	186
14	UP&L	19,326	19,325	1	0.01%	19,306
15	PACIFICORP	16,060	16,060	0	0.00%	16,060
16	IPCO - LONG-TERM	13,910	13,756	154	1.12%	13,769
17	SHORT-TERM FIRM	3,600	3,572	28	0.78%	3,501
18	VALMY USAGE	4,620	4,550	70	1.54%	4,461
19	SURPLUS ECONOMY	3,608	3,545	63	1.78%	3,483
20	QUALIFYING FACILITIES	32,563	32,563	0	0.00%	32,563
21						
22	TOTAL PURCHASED POWER COSTS	96,206	95,890	316	0.33%	95,662
23						
24	TOTAL FUEL & PURCHASED POWER COSTS	167,915	167,126	789	0.47%	167,173
25						
26	FRANCHISE & UNCOLLECTIBLES (F&U) EXPENSE					
27	(LN 24 * 1.91%)	3,207	3,192	15	0.47%	3,193
28						
29	TOTAL FUEL AND PURCHASED POWER COST					
30	REVENUE REQUIREMENT (1)	171,122	170,318	804	0.47%	170,366
31						
32	ECAC RECOVERY (LN 30 * 78%)	133,475	132,848	627	0.47%	132,885
33						
34	FUEL INVENTORY REVENUE REQUIREMENT					
35	(PAGE 3, LN 24)	885	695	190	27.34%	697
36						
37	ECAC RECOVERY (LN 35 * 78%)	690	542	148	27.31%	544
38						
39	TOTAL ECAC RELATED COSTS (LNS 32+37)	134,165	$133,390	$775	0.58%	133,429
40						
41	TOTAL SYSTEM MWH SALES	5,766,329	5,766,329	0	0.00%	5,766,329
42						
43	ECAC OFFSET RATE (MILLS) (LN 39/LN 41)	23.27	23.13			23.14
44						
45	BALANCING RATE (MILLS)	(3.00)	(3.04)			(3.04)
46						
47	ECAC BILLING FACTOR (MILLS)	20.27	20.09			20.10
48						
49						
50	(1) DIFFERENCE RESULTS FROM SIERRA'S LOWER HYDRO FORECAST.					

COMPARATIVE EXHIBIT NO. 22
SIERRA PACIFIC POWER COMPANY
CALCULATION OF AER
APPLICATION NO. 90-08-068

LINE NO.				SIERRA > DRA DIFFERENCE		
1	FUEL INVENTORY BILLING FACTOR:	SIERRA	DRA	$	%	ADOPTED
2	DIESEL OIL					
3	AVERAGE INVENTORY LEVEL (BBLS)	5,656	4,971	685	13.78%	5,532
4	AVERAGE COST ($/BBLS)	$29.82	$29.82	$0.00	0.00%	29.82
5	INVENTORY VALUE ($000)	$169	$148	$21	14.19%	$165
6	RESIDUAL OIL					
7	AVERAGE INVENTORY LEVEL (BBLS)	281,964	255,205	26,759	10.49%	255,205
8	AVERAGE COST ($/BBLS)	$18.42	$18.42	$0.00	0.00%	18.42
9	INVENTORY VALUE ($000)	$5,194	$4,701	$493	10.49%	4,701
10	COAL					
11	AVERAGE INVENTORY LEVEL (TONS)	139,461	94,689	44,772	47.28%	94,689
12	AVERAGE COST ($/TON)	$42.58	$42.58	$0.00	0.00%	42.58
13	INVENTORY VALUE ($000)	$5,938	$4,032	$1,906	47.27%	4,032
14						
15	TOTAL INVENTORY VALUE (LNS 5+9+13)	$11,301	$8,881	$2,420	27.25%	$8,890
16						
17	FORECASTED BANKERS ACCEPTANCES RATE	7.68%	7.68%	0.00%	0.00%	7.68%
18						
19	CARRYING COST OF FUEL INVENT (LN 15X17)	$868	$682	$186	27.27%	$683
20						
21	FRANCHISE & UNCOLLECTIBLES (F&U) EXPENSE					
22	(LN 19 * 1.91%)	17	13	4	30.77%	14
23						
24	TOTAL FUEL INVENTORY REVENUE REQ. (1)	885	695	190	27.34%	697
25						
26	AER RECOVERY (LN 24 * 22%)	195	153	42	27.45%	153
27						
28	TOTAL FUEL AND PURCHASED POWER COST					
29	REVENUE REQUIREMENT	171,122	170,318	804	0.47%	170,366
30						
31	AER RECOVERY (LN 29 * 22%)	37,647	37,470	177	0.47%	37,481
32						
33	TOTAL AER RELATED COSTS (LNS 26+31)	$37,842	$37,623	219	0.58%	37,634
34						
35	TOTAL SYSTEM MWH SALES	5,766,329	5,766,329	0	0.00%	5,766,329
36						
37	AER RATE (MILLS) (LN 33/LN 35)	6.56	6.52			6.53
38						
39						
40	(1) DIFFERENCE RESULTS FROM SIERRA'S HIGHER AVERAGE INVENTORY LEVELS.					

APPENDIX A

SIERRA PACIFIC POWER COMPANY
Electric Department - California Jurisdiction
ADOPTED SYSTEM AVERAGE PERCENTAGE CHANGE REVENUE ALLOCATION 1/
Forecast Period: April 1, 1991 to March 31, 1992

CUSTOMER GROUP	SALES (MWh)	PRESENT RATE REV ($000s)	SAPC ($000s)	% DECR	AVERAGE RATE ($/KWh)
RESIDENTIAL	229,327	$20,111	$18,404	0.0849	0.0803
COMMERCIAL					
A-1	94,844	$7,329	$6,707	0.0849	0.0707
A-2	54,208	$3,952	$3,617	0.0848	0.0667
A-3	67,751	$4,280	$3,916	0.085	0.0578
AGRICULTURE	250	$11	$10	0.0909	0.04
STREETLIGHTS	1,233	$220	$214	0.0273	0.1736
TOTAL	447,613	$35,903	$32,868	0.0845	0.0734

1/ Street and overhead lighting facilities charges have been excluded from the revenue allocation process. However, that amount has been added to the figures in this table to obtain the correct percentage increases and average rate calculations.

APPENDIX A

SIERRA PACIFIC POWER COMPANY
Electric Department - California Jurisdiction
ADOPTED RESIDENTIAL RATES
Forecast Period: April 1, 1991 to March 31, 1992

SCHEDULE/COMPONENT	PRESENT RATE $/Unit/Mo	PROPOSED RATE $/Unit/Mo	% DECR
D-1/DM-1 (2)			
Customer Charge	$3.00	$3.00	0
Tier 1 Perm Baseline	0.06426	0.06023	0.0627
Tier 2 Non-Perm/Excess	0.09334	0.08378	0.1024
DS-1 (2)			
Customer Charge	$3.00	$3.00	0
Tier 1 Perm Baseline	0.06426	0.06023	0.0627
Tier 2 Non-Perm/Excess	0.09334	0.08378	0.1024

(2) This decision reduces the differential between Tier 1 and Tier 2 by 25%. The differential is calculated based on a composite rate which includes the customer charge and the Tier 1 energy rate:

Tier 2 energy rate	0.09334	0.08378	0.1024
Tier 1 composite rate	0.07164	0.06751	0.0576
Tier Differential	0.0217	0.01627	0.2502

APPENDIX A

SIERRA PACIFIC POWER COMPANY
Electric Department - California Jurisdiction
ADOPTED COMMERCIAL RATES
Forecast Period: April 1, 1991 to March 31, 1992

SCHEDULE/COMPONENT	PRESENT RATE $/Unit/Mo	PROPOSED RATE $/Unit/Mo	% DECR
A-1: Small Commercial			
Customer Charge	$5.00	$5.00	0
Energy Rate	0.07414	0.06758	0.0885
A-2: Medium Commercial			
Customer Charge	$50.00	$50.00	0
Winter On-Peak Demand	6.71	6.71	0
Summer On-Peak Demand	9.00	9.00	0
Energy Rate	0.04781	0.04161	0.1297
A-3: Large Commercial			
Customer Charge	$200.00	$200.00	0
Winter On-Peak Demand	3.44	3.44	0
Winter Mid-Peak Demand	2.85	2.85	0
Summer On-Peak Demand	7.65	7.65	0
Non TOU	2.00	2.00	0
ENERGY RATES			
Winter On-Peak	0.04523	0.03943	0.1282
Mid-Peak	0.04496	0.03919	0.1283
Off-Peak	0.03748	0.03267	0.1283
Summer On-Peak	0.04378	0.03816	0.1284
Off-Peak	0.03743	0.03263	0.1282
PA: Interruptible Irrigation			
Customer Charge	$5.00	$5.00	0
ENERGY RATE Summer	0.04183	0.03799	0.0918

APPENDIX A

SIERRA PACIFIC POWER COMPANY
Electric Department - California Jurisdiction
ADOPTED STREET AND OVERHEAD LIGHTING RATES
Forecast Period: April 1, 1991 to March 31, 1992

LAMP TYPE	KWh/Mo	PRESENT RATES $/Unit/Mo	PROPOSED RATES $/Unit/Mo	% DECR
STREET LIGHTS				
High Pressure Sodium				
5800 Lumen	29	$7.23	$7.08	0.0207
9500 Lumen	41	7.78	7.57	0.027
16000 Lumen	59	8.74	8.43	0.0355
22000 Lumen	79	9.84	9.43	0.0417
OUTDOOR LIGHTS				
High Pressure Sodium				
5800 Lumen	29	5.53	5.38	0.0271
9500 Lumen	41	6.26	6.05	0.0335
16000 Lumen	59	7.49	7.14	0.0467
22000 Lumen	79	8.54	8.10	0.0515

(END OF APPENDIX A)

SPPCO A90-08-068 : TENTATIVE STIPULATION ON REVENUE ALLOCATION

Sierra and DRA agree that in future ECAC filings Sierra will adopt revenue allocation methods as set forth below.

A.91-00-000 Sierra's ECAC proceeding : Sierra will file using an Equal Percentage of Marginal Cost (EPMC) allocation based on a modified version of the marginal cost study approved in Sierra's TY 1990 General Rate Case (GRC). This last approved marginal cost study will only be modified to reflect the growth in customers and sales levels, by class of customer, from Sierra's TY 1990 GRC to the 1991 ECAC filing.

A92-00-000 Sierra's ECAC proceeding : The first in a series of three ECAC filings subsequent to and included in the three year GRC cycle associated with the filing of Sierra's TY 1993 GRC, Sierra will file using the System Average Percentage Change (SAPC) allocation method. When a decision is reached in Sierra's TY 1993 GRC, the EPMC allocation from the GRC will be applied to the ECAC filing to develop final effective rates.

A.93-00-000 Sierra's ECAC proceeding, the second in a series of three ECAC filings subsequent to and included in the three year GRC cycle associated with the filing of Sierra's TY 1993 in the GRC proceeding, Sierra will file using the EPMC allocation from the marginal cost study approved in Sierra's TY 1993 GRC, modified to reflect: a) the customers and sales levels, b) the generation level marginal energy costs in the 1993 ECAC proceeding, and c) inflation to marginal customer costs and marginal demand costs based on changes in the Gross National Product Deflator (GNPD) from the GRC implementation data to the most current value available at the time the ECAC filing is made. No other elements of the last approved marginal cost study will be changed.

A.94-00-000 Sierra's ECAC proceeding : The third in a series of three ECAC filings subsequent to and included in the three year GRC cycle associated with the filing of Sierra's TY 1993 GRC, Sierra will file using the EPMC allocation from the 1993 ECAC filing, with modification only to reflect the 1994 ECAC customer and sales numbers.

For subsequent ECAC proceedings which will be elements of the three year cycles of ECAC filings following each GRC filing subsequent to the TY 1993 GRC, the same pattern of procedures defined for the 1992 thru 1994 ECAC filings above will be followed. The procedure defined for the 1992 ECAC filing relative to the TY 1993 GRC, will be repeated for the 1995 ECAC filing, relative to the TY 1996 GRC, and so on to repeat the pattern defined above for future GRC cycles.

The above recommendation supercedes the recommendations made in 2.11, 2.12, 2.13, 12.9, 12.10, and 12.11.

APPENDIX B
Page 2

Sierra and DRA further agree that since the stipulation adopted in decision D. 90-07-060 applied only to Sierra's 1990 General Rate Case, 12.3 should be changed as follows :

12.3 ...... Sierra and DRA agreed to, and the Commission adopted the 100% EPMC method of revenue allocation in last year's Sierra proceeding (GRC, A.89-08-027 , D.90-07-060). According to this decision, D.90-07-060, Sierra and DRA both accepted the 100% EPMC method of revenue allocation to develop rates which reflect marginal costs in the GRC proceedings.

12.4 is to be changed as follows also :

12.4 ...... In the SAPC method, all customer classes receive an equal percentage change of the total change in revenue.

It should be noted, DRA has accepted Sierra's proposed (SAPC) revenue allocation procedure for this ECAC filling.

SIERRA PACIFIC POWER COMPANY - APPLICATION A90-08-068
CALIFORNIA ECAC, ATTRITION, and GRC FILING and RATE EFFECTIVE CYCLES UNDER TENTATIVE STIPULATION on REVENUE ALLOCATION

Aug '91 — Jun '92 — Aug '92 — Jun '93 — Aug '93 — Jun '94 — Aug '94 — Jun '95 — Aug '95 — Jun '96

ECAC Cycles:

1991 ECAC Filing w/ TY and 3/93 & EPMC Revenue Allocation Based on 1990 GRC Marginal Cost Study Adjusted for Customers & Sales in 1991 ECAC Filing
*------------------------------#

1992 ECAC Filing w/ TY and 3/94 & SAPC Revenue Allocation at Filing, Corrected to GRC EPMC Allocation After 1993 GRC Decision
*------------------------------#

1993 ECAC Filing w/ TY and 3/95 & EPMC Revenue Allocation Based on 1993 GRC Marginal Cost Study with Updated Marginal Energy Costs, Customers & Sales to ECAC Values & Marginal Demand & Customer Costs Inflated from 1993 Using GAPO
*------------------------------#

1994 ECAC Filing w/ TY and 3/96 & EPMC Revenue Allocation Based on 1993 ECAC Allocation Adjusted for Customers & Sales in 1994 ECAC Filing
*------------------------------#

1995 ECAC Filing w/ TY and 3/9[illegible] & SAPC Revenue Allocation at Fil[illegible] Corrected to GRC EPMC Allocati[illegible] After 1996 GRC Decision
*------------------------------

ARA Cycles:

TY 1992 ARA
*-----------#

TY 1994 ARA
*-----------#

TY 1995 ARA
*-----------#

GRC Cycles:

TY 1993 GRC Filing Using EPMC Allocation Based on a Fully Updated Marginal Cost Study
*------------------------------#

TY 1996 GRC Filing Using EPMC Allocation Based on a Fully Updated Marginal Cost Study
*------------------------------#

Rate Effective Cycles:

----- 1990 GRC Rate Cycle -----|<----- 1993 GRC Rate Cycle -----|<-- 1996 GRC [illegible]

1991 ECAC Rates | 1992 ARA Rates | 1992 ECAC Rates | 1993 GRC Rates | 1993 ECAC Rates | 1994 ARA Rates | 1994 ECAC Rates | 1995 ARA Rates | 1995 ECAC Rates | 1996 GRC Ra[illegible]

Rates Driven by 1990 GRC Marginal Cost Study --->|<--- Rates Driven by 1993 GRC Marginal Cost Study --->|<--- Rates Driven by 1993 ECAC Adjustments to 1993 GRC Marginal Cost Study --->|<---

* Filing Dates
\# Rate Effective Dates

(END OF APPENDIX B)