ALJ/MSW/jt *

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Decision 90 07 060 JUL 18 1990

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SIERRA PACIFIC POWER COMPANY for general rate relief and for authority to increase its electric rates and charges for electric service.	Application 89-08-027 (Filed August 16, 1989)
Order instituting investigation of SIERRA PACIFIC POWER COMPANY electric rates and charges for electric service.	I.90-02-007 (Filed February 7, 1990)

James D. Salo and John Madariaga, Attorneys at Law, for Sierra Pacific Power Company, applicant.
Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for Heavenly Valley Ski Area, interested party.
Alberto Guerrero, Attorney at Law, for Division of Ratepayer Advocates.

O P I N I O N

Summary

This decision adopts a proposed stipulation of Sierra Pacific Power Company (SPPC) and the Division of Ratepayer Advocates (DRA) which resolves all issues that were contested by the two parties. The stipulation provides for a 1990 test year revenue requirement of $22.128 million at proposed rates, which represents a reduction of $1.699 million from present-rate revenues of $23.827 million.

To avoid problems resulting from too-frequent rate changes, the new rates implementing the adopted revenue requirement and rate design will become effective concurrent with rate adjustments resulting from SPPC's pending Energy Cost Adjustment

Clause (ECAC) and Electric Rate Adjustment Mechanism (ERAM) proceedings (Application (A.) 89-08-044 and A.89-08-046). The authorized revenue reduction is made effective August 1, 1990 through an adjustment to the authorized ERAM base revenues.

Background

SPPC is engaged primarily in the generation, purchase, transmission, distribution, and sale of electricity in Northern Nevada and the Lake Tahoe area of California. SPPC also provides water and gas service to the Reno/Sparks area of Northern Nevada. Electric service is provided to approximately 227,000 customers in a service territory of approximately 50,000 square miles. On June 30, 1989 California jurisdictional customers numbered approximately 39,500.

SPPC was last granted a general rate increase by Decision (D.) 86-02-030 dated February 6, 1986 in A.85-05-017. On August 16, 1989 SPPC filed this general rate case application (A.89-08-027), requesting authority to raise its California jurisdictional base rate revenues by $1.539 million for test year 1990. The requested revenue requirement reflects the 10.98% rate of return on rate base which SPPC had earlier requested in its then-pending annual cost of capital application (A.89-06-015). SPPC also requests authority to file attrition revenue adjustments beginning in 1991 and continuing until its next general rate case.

On August 28, 1989 SPPC filed applications to initiate its annual ECAC and associated ERAM proceedings (A.89-08-046 and A.89-08-044, respectively). A decision in those consolidated matters is pending.

By D.89-11-068 dated November 22, 1989 the Commission adopted the 1990 ratemaking cost of capital for California's major energy utilities. In that consolidated proceeding, which included SPPC's A.89-06-015, we authorized a return on common equity of 13.00% and an overall return on rate base of 10.34% for SPPC. We provided that the authorized rate of return shall be used for calculating the revised 1990 test year rates in conjunction with SPPC's 1990 general rate case proceeding.

On February 7, 1990 the Commission instituted an investigation (I.90-02-007) into the rates, charges, and practices of SPPC, and ordered that the investigation proceeding be consolidated with A.89-08-027. The stated purpose of the Commission in instituting the investigation was to "have a procedural forum and vehicle to fully act on recommendations on revenue requirement, rates, practices and other aspects of SPPC's operations which may be beyond the confines of the relief requested in A.89-08-027."

DRA

DRA assigned a team of engineers, economists, accountants, and analysts to perform an extensive and complete analysis of SPPC's showing. The review included an audit of SPPC's accounting and financial records to determine whether recorded financial data was fairly stated and in conformance with the Uniform System of Accounts and generally accepted accounting principles. On February 21 and February 26, 1990 DRA mailed its proposed exhibits. The showing consisted of four volumes covering the qualifications and prepared testimony of 15 professional witnesses, a results of operation study, a financial audit, and a study of marginal costs, revenue allocation, and rate design. Based on its review, DRA recommended a rate reduction of $2.002 million for test year 1990.

Hearings

Prehearing conferences were held at San Francisco on October 26, 1989 and on March 5, 1990 to identify the parties and their positions, discuss scheduling, and identify issues. Appearances were filed by SPPC and DRA at the first prehearing conference. No other parties appeared to intervene.

A public participation hearing was held at South Lake Tahoe on March 6, 1990. Notice of this hearing was inserted in customer bills or mailed separately to customers on February 20, 1990. Statements were made by four public witnesses, who addressed high baseline/second tier rate differentials, seemingly constant increases in rates for utility services of all kinds, and high electric bills. Representatives of SPPC and DRA were present to answer customer questions about SPPC's operations and about the positions of SPPC and DRA on the issues in this proceedings.

Evidentiary hearings were held in San Francisco on March 12 and March 15, 1990 before Administrative Law Judge (ALJ) Wetzell. At the March 12 hearing counsel for DRA requested a postponement on behalf of SPPC and DRA, advising that the parties were close to stipulating on all issues and that the proceeding would be expedited with the postponement. No other parties were present at the March 12 hearing, and the matter was adjourned without taking of evidence.

Hearings were reconvened on March 15, 1990. Counsel for SPPC advised that SPPC and DRA had reached a stipulated settlement of all issues on that date, and that they were prepared to make a joint motion for its approval and adoption in lieu of substantive hearings. The "Stipulation of Parties of Record" (the stipulation) was received as Exhibit 13.[1]

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1 Rule 51 of the Rules of Practice and Procedure defines the terms "settlement" and "stipulation " as follows:

"(c) 'Settlement' means an agreement between some or all of the parties to a Commission proceeding on a mutually acceptable outcome to the proceedings. In addition to other parties to an agreement, settlements in applications must be signed by the applicant and in complaints, by the complainant and defendant."

"(d) 'Stipulation' means an agreement between some or all of the parties to a Commission proceeding on the

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Heavenly Valley Ski Area (Heavenly) entered an appearance at the March 15, 1990 hearing. Heavenly expressed concern about the potential impact that the stipulated rate schedule for A-3 customers would have on its billings. The ALJ granted Heavenly's request to allow comments on the stipulation in accordance with the stipulation and settlement rules in Article 13.5 of the Rules of Practice and Procedure (the settlement rules).

In accordance with the settlement rules, SPPC and DRA jointly filed a motion for approval of the stipulation on March 26, 1990. Heavenly filed comments on April 25, 1990, and SPPC filed a response on May 11, 1990.

Proposed Stipulation

After DRA's proposed exhibits were mailed, DRA and SPPC began a series of communications and meetings to explore the possibilities for stipulation on an issue-by-issue basis. The parties note that during this process SPPC accepted many of DRA's recommendations, and argue that the stipulation is clearly in the public interest and represents a resolution that is fair and reasonable for both SPPC and its California customers. Further, the parties note that it alleviates the need for major commitment of time and resources that would otherwise be devoted to litigating the case in full.

The full text of the stipulation along with Appendix A (summaries of earnings at present and proposed rates) and

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(Footnote continued from previous page)

> resolution of any issue of law or fact material to the proceeding."

Although the stipulation of SPPC and DRA appears to be a settlement within the meaning of Rule 51, we have adopted the parties' use of the term "stipulation" for purposes of clarity.

Appendix F (summary of billing determinants) of the stipulation are attached to this decision as Appendix A. By letter dated March 22, 1990 the stipulating parties advised the ALJ of two errors affecting one number in the stipulation, and requested that appropriate corrections be made. Page 6, line 5 and Appendix F, page 2 show that California jurisdictional sales are 428,767 megawatt-hour (MWh) and 428,623 MWh, respectively. The corrected sales figure in each case is 429,015 MWh. Since they are minor in nature and were requested by both SPPC and DRA, we will adopt the corrections as requested.

The stipulation sets forth agreed-upon principles for rate design and for attrition rate adjustment filings for 1991 and 1992. SPPC and DRA jointly sponsored late-filed Exhibit 14, which sets forth their proposed rates for test year 1990, and late-filed Exhibit 15, which sets forth their revenue requirements calculations for the attrition filings. Exhibits 14 and 15 are incorporated in this decision as Appendices B and C, respectively.

<u>Discussion</u>

The only issues requiring discussion are whether the stipulation should be adopted, and whether Heavenly's concern over the proposed rate design for A-3 customers requires any revision to the adopted rates or other action.

We conclude that approval and adoption of the stipulation is in the public interest. After a complete and extensive analysis of SPPC's showing and a full review and audit of the utility's operations and records, DRA independently arrived at and published its recommendations for this proceeding, including a recommended $2.002 million reduction in SPPC's 1990 revenue requirement. Negotiations that eventually resulted in the stipulation began only after DRA published its recommendations. We note, as SPPC witness Franklin testified, that most of the significant revenue requirement changes from the original application which are reflected in the stipulation represent SPPC's acceptance of DRA positions on major issues. These include DRA's sales estimates, its ratemaking treatment of SPPC's new general office building, the early retirement program, forecasted plant additions, and the rate of return adopted in D.89-11-068. In the opinion of DRA's witness Chan, the stipulation serves the best interests of ratepayers and the overall public interest. Chan supported SPPC's testimony that the company has agreed to accept virtually all of DRA's adjustments. Finally, we note that the stipulation addresses concerns raised at the public participation hearing by providing residential rate reductions and by reducing first and second tier rate differentials.

As explained by SPPC witness Loomis, the rate design proposals of the stipulation are the product of extensive negotiations, particularly with respect to the A-3 class rate design. SPPC had originally proposed a customer charge of $700, an on-peak demand charge of $10.74, and a winter mid-peak demand charge $2.87. DRA had proposed a customer charge of $200, on-peak demand charges of $4.59 in winter and $7.00 in summer, a winter mid-peak demand charge $0.95, and a maximum demand charge of $5.03 to recover distribution investment. The stipulation represents a middle ground with a customer charge of $200, on-peak demand charges of $3.44 in winter and $7.65 in summer, a winter mid-peak demand charge $2.85, and a maximum demand charge of $2.00.

Heavenly notes that the A-3 class as a whole receives substantial rate reductions under the stipulation. Exhibit 16 shows that while the A-3 class receives a 14.61% billing reduction, Heavenly receives a 2.2% increase. (Exhibit 16 also shows that under SPPC's original proposal, Heavenly would receive a 2.36% decrease compared to an overall Class A-3 decrease of 6.25%, and that under the original DRA proposal, Heavenly would receive a 33.11% increase compared to an overall Class A-3 decrease of 7.45%.) SPPC witness Loomis testified that both the company and DRA believe a mid-peak demand charge is appropriate because having only on-peak charges fails to reflect the cost responsibility for facilities necessary to support maximum loads of individual customers. Loomis noted that the DRA proposal went further in recommending a non time-of-use (TOU) demand charge, which was also based on the rationale that there should be cost sharing of facilities related to the maximum demand of individual customers. He described the negotiations with DRA as follows:

> "[I]n our discussions to come to a compromise we tried to examine the impacts of our original proposal as well as DRA's alternative proposal and come to a middle ground that went both in the direction of the cost study but mitigated, as best we could, the impacts on individual customers."

DRA rate design witness Auriemma believes the stipulation mitigates bill impacts while restructuring rates to more accurately reflect costs. Auriemma noted that it is DRA policy to develop rates which accurately reflect marginal costs.

In its comments on the stipulation, Heavenly states that it does not request a hearing on rate design issues but rather an opportunity to express its dissent and concerns and an opportunity to participate in the rate design deliberations contemplated by the stipulation, which are to occur before SPPC's next general rate case. Heavenly states that it has made substantial investments in alternate generating facilities in response to present rate design signals, and that the new maximum demand charge which is imposed without regard to when demand occurs, as well as the winter mid-peak demand charge, could undermine the economic basis of those investments. Heavenly notes that under the new rate design it could be economically attractive to use SPPC power to make snow during winter on-peak hours, and that if it and other ski resorts were to do so, the entire basis of cost allocation for the A-3 class could be changed.

In evaluating whether and how to address Heavenly's objections to the stipulation, we are concerned not only with the substantive merits of those objections but also the process by which they were raised. There is only one objection to the entire stipulation dealing with a narrow rate design issue, and Heavenly does not request a hearing. Since the stipulation provides that either party may withdraw in the event of Commission-ordered changes, we are not inclined to modify the rate design for Class A-3 in the absence of substantive reasons for doing so.

Further, we note that while our settlement rules are designed to ensure that all parties are included in the negotiation process leading to stipulation and settlement, that purpose can be achieved only when the parties are known. In this case two prehearing conferences, a public participation hearing, and an evidentiary hearing were convened before Heavenly filed an appearance. Under the Rate Case Plan for energy utilities, applicants in general rate cases serve their filings on parties to the last case, and all customers are required to receive notice of the filing. If Heavenly had entered an appearance earlier in the proceedings, SPPC and DRA would have been required to convene a conference with notice and opportunity to participate accorded to Heavenly. We note that Heavenly appeared in SPPC's last general rate case (A.85-05-017, decided by D.86-02-030), to address A-3 rate design issues which included a Public Staff Division (predecessor of DRA) proposal to establish non-TOU demand charges. In view of Heavenly's prior interest in A-3 rate design, it could have anticipated that rate design issues affecting its future billings would be addressed in this proceeding, particularly since we announced our intention to consider non-TOU demand charges in SPPC's next general rate case. (Re Sierra Pacific Power Company, (1986) 20 CPUC 2d 457, 483.) Additionally the testimony demonstrates that a significant amount of negotiations were devoted to the problems of A-3 rate design and to balancing the movement towards marginal cost-based rates with the need to mitigate the effects of such movement. Under these circumstances we are even less inclined to modify the proposal.

We conclude the A-3 rate design proposal of the stipulation is reasonable and should be adopted. It represents the efforts of the parties to respond to our policy of movement towards marginal cost rate design while considering the need for rate stability and impacts on individual customers. The 2.2% billing increase indicated for Heavenly is dramatically lower than the 33.1% increase indicated under DRA's original proposal. While the movement we are adopting may be somewhat more abrupt in this case than it has been on other occasions, it appears to be preferable to accomplish such rate design changes when overall reductions in revenue requirements are indicated, as in this proceeding.

SPPC recognizes Heavenly's desire to be a part of deliberations on rate design leading to the next general rate case, but believes it is not necessary for the Commission to mandate a particular level of participation. We agree with SPPC. At the same time, we wish to emphasize our agreement that such participation will be important to a meaningful resolution of issues, and that we expect SPPC to take necessary steps to assure an opportunity for meaningful participation at appropriate stages of the rate design studies provided in the stipulation.

In reviewing the stipulation's provisions for marginal cost, revenue allocation, and rate design, we find three matters requiring comment. First, the stipulation provides (at page 11) that target residential baseline allowances as proposed by DRA will be implemented in annual filings, consistent with current practice. We wish to emphasize that these changes in baseline quantities should be accompanied by any changes in rates which are necessary to make the baseline changes revenue-neutral. Second, although the stipulation makes provision for several reviews and studies on marginal costs and rate design, we believe that SPPC should explicitly study the impact of the adopted rate design for A-3 customers on usage patterns, either in conjunction with or in addition to the reviews provided in the stipulation. Finally, since most of SPPC's load is in Nevada, we believe that its review of costing/rating period definitions (Stipulation, page 11) should not be limited to load characteristics in California but should reflect the load on an overall system basis as well.

Comments

SPPC filed comments on the ALJ's proposed decision on July 9, 1990. SPPC notes that the stipulation provides that rate adjustments resulting from this proceeding will be implemented on August 1, 1990, concurrent with those resulting from its pending ECAC/ERAM proceeding. According to SPPC, simultaneous rate adjustments are desirable because they result in less customer confusion and reduce the likelihood of billing error. Due to uncertainty of the date of the ECAC/ERAM decision, SPPC requests that the combined rate changes be made effective on September 1, 1990. SPPC points out that the effective date of the revenue reductions resulting from this order can still be made effective on August 1 through the alternative of reducing the authorized ERAM base revenues. DRA filed reply comments indicating that it does not oppose SPPC's request provided that the ERAM base revenues are reduced on August 1 as suggested by SPPC.

We are mindful that too-frequent rate changes can be confusing to customers and add to a utility's administrative burden, and will therefore grant SPPC's request as supported by DRA. However, we also note that the Commission's next scheduled meeting is on August 8, 1990, and that the following meeting is scheduled for September 12, 1990. We therefore anticipate that the ECAC/ERAM matter may not be considered by the Commission until September 12, 1990, and that the combined rate changes will become effective on October 1, 1990.

Findings of Fact

1. On August 16, 1989 SPPC filed A.89-08-027, requesting an increase in base rate revenues of $1.539 million for the 1990 test year.

2. On February 7, 1990 the Commission instituted an investigation (I.90-02-007) into the rates, charges, and practices of SPPC, and ordered that the investigation proceeding be consolidated with A.89-08-027.

3. By D.89-11-068 the Commission authorized a rate of return of 10.34% to be applied in SPPC's 1990 general rate case.

4. Properly noticed prehearing conferences were held on October 26, 1989 and March 5, 1990, a public participation hearing was held at South Lake Tahoe on March 6, 1990, and evidentiary hearings were held on March 12 and 15, 1990.

5. DRA assigned a team of 15 engineers, economists, accountants, and analysts to perform an extensive and complete analysis of SPPC's showing.

6. DRA mailed its proposed exhibits on February 21 and February 26, 1990. The showing included reports on a results of operation study, a financial audit, and a study of marginal costs, revenue allocation, and rate design, and based on the review, DRA recommended a rate reduction of $2.002 million for test year 1990.

7. Following the mailing of DRA's showing, SPPC and DRA initiated communications to explore stipulation and settlement of issues.

8. DRA and SPPC entered into the stipulation attached in part as Appendix A on March 15, 1990. The stipulation provides for a reduction in SPPC's 1990 test year revenue requirement of $1.699 million.

9. Appendices B and C represent the joint proposals of SPPC and DRA for 1990 adopted rates and for 1991 and 1992 attrition rate adjustment filings, respectively.

10. During the process leading to the stipulation and up to date of stipulation, DRA and SPPC were the only parties of record.

11. Heavenly entered an appearance on March 15, 1990.

12. Heavenly does not request additional hearings on A-3 rate design.

13. The rate design for A-3 customers set forth in the stipulation represents the efforts of the parties to respond to our policy of movement towards marginal cost rate design while considering the need for rate stability and impacts on individual customers.

14. The stipulation constitutes a just and fair resolution of all contested matters in these proceedings.

15. The stipulation is in the overall public interest as well as the interest of SPPC and its customers.

16. The adjustments in rates and charges authorized by this decision are reasonable, and the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable.

17. SPPC requests that implementation of rate changes be deferred pending a decision in its current ECAC/ERAM proceeding, and suggests that the revenue reductions agreed to be made effective August 1, 1990 through reductions in authorized ERAM base revenues.

<u>Conclusions of Law</u>

1. The proposed stipulation filed by SPPC and DRA should be adopted.

2. The reduced revenue requirement reflected in the Stipulation should be made effective August 1, 1990 through a reduction in the authorized ERAM base revenues.

3. SPPC should be authorized and directed to file revised rate schedules reflecting the rates and rate adjustments set forth in Appendix B, to become effective concurrently with rates and rate adjustments adopted in SPPC's ECAC/ERAM proceeding.

4. SPPC should be authorized to file attrition rate adjustments for 1991 and 1992 in accordance with the stipulation and Appendix C.

5. The order should be effective on the date signed because there is an immediate need for the revenue reductions authorized.

O R D E R

IT IS ORDERED that:

1. The joint motion for approval of the stipulation filed by Sierra Pacific Power Company (SPPC) and the Division of Ratepayer Advocates is granted.

2. Within 5 days from the effective date of this order, SPPC shall file a revised Preliminary Statement to be effective August 1, 1990. The Preliminary Statement shall show SPPC's authorized Base Revenue Amount resulting from the adopted changes in revenue requirements for test year 1990 as shown in Appendix A. Rate changes resulting from this order shall be effective concurrently with other rate changes as may be ordered by the Commission in SPPC's pending Energy Cost Adjustment Clause proceeding (Application (A.) 89-08-046 and A.89-08-044). Such filings shall comply with General Order 96-A and shall be effective not less than 5 days after filing, to become effective August 1, 1990, and shall be applicable to service rendered on and after the effective date of the tariffs.

3. SPPC is authorized to file attrition rate adjustments for 1991 and 1992 in accordance with the methodology adopted in Appendix C.

This order is effective today.

Dated JUL 18 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

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

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

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APPENDIX A

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

IN THE MATTER OF THE APPLICATION OF SIERRA PACIFIC POWER COMPANY FOR GENERAL RATE RELIEF AND FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES AND CHARGES FOR ELECTRIC SERVICE.	No. 89-08-027 (U-903-E)
ORDER INSTITUTING INVESTIGATION OF SIERRA PACIFIC POWER COMPANY ELECTRIC RATES AND CHARGES FOR ELECTRIC SERIVCE.	No. I-90-02-007

STIPULATION OF PARTIES OF RECORD

I

Introduction

Sierra Pacific Power Company (Sierra Pacific) and the Division of Ratepayer Advocates (DRA), the only parties of record in the above-described proceedings, enter into this Stipulation for the purpose of providing to the Public Utilities Commission of California (Commission) a recommended resolution of all issues in these proceedings. The Stipulation includes this text and the Appendicies attached hereto as well as the comparative revenue requirements (Appendix A) and the comparative rate design (Appendix B).

The parties urge the Commission to find that the costs and non-cost elements contained in the Stipulation are just and reasonable for Sierra Pacific's operations in the State of California for the Test Year 1990.

II

Background

On August 16, 1989, Sierra Pacific filed an Application for general rate relief for its California electric operations. The filing was transmitted to the Commission and all parties of record in Sierra Pacific's last general rate case and to appropriate governmental agencies.

The rate filing was accompanied by a full set of workpapers supporting Sierra Pacific's estimates of expenses and revenues. The filing gave notice of Sierra Pacific's intent to request authority to recover the revenue requirement resulting from Sierra Pacific's costs of owning and operating facilities necessary to provide electrical service in its certificated service territories. These costs included estimates of all non-fuel related operation and maintenance expenses, depreciation, taxes, and a fair return on ratebase (which return was subsequently determined by the Commission in Decision No. 89-11-068). Sierra Pacific's rate filing also included estimates for levels of electric sales and proposed rates designed to enable the company to recover its estimated costs at those sales levels.

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On February 7, 1990, the Commission issued an Order Instituting Investigation, I. 90-02-007, to provide ". . . a procedural forum and vehicle to fully act on recommendations on revenue requirement, rates, practices and other aspects of SPPC's operations which may be beyond the confines of relief requested in A. 89-08-027", which was consolidated with this proceeding for consideration and hearing.

Prehearing conferences were held on October 26, 1989 and March 5, 1990. A public participation hearing within the service territory was held on March 6, 1990. The assigned Administrative Law Judge Mark S. Wetzell, set the case for hearings commencing on March 12, 1990. No entities other than DRA entered appearances or intervened in the proceedings. Pursuant to informal stipulation of the parties, ALJ Wetzell formally convened the hearings on March 12, 1990 and immediately continued the hearings until Thursday, March 15, 1990, based upon the representation of the parties that this Stipulation was agreed to in principal and would be finalized by that date.

Starting before Sierra Pacific made its filing and continuing through March, 1990, DRA propounded numerous data requests to Sierra Pacific covering all aspects of Sierra Pacific's Application. DRA also assigned a team of auditors over a period of months to personally review the financial, accounting and operating records of Sierra Pacific at its main office in Reno, Nevada. The parties to this Stipulation believe DRA's review of Sierra Pacific's Application and supporting materials was both extensive and complete.

On February 21, 1990, DRA mailed its proposed exhibits, consisting of its Reports analysing Sierra Pacific's 1990 Test Year rate filing for its California operations. Overall, DRA's cost and resulting revenue requirements estimates were below, and its sales level estimate differed from the estimates used by Sierra Pacific. On February 26, 1990, DRA distributed its proposed exhibits consisting of its Report on Cost of Service Studies and Rate Design.

Sierra Pacific and DRA shared a desire to explore the settlement of some or all of the issues in this matter once DRA's exhibits and reports had been completed. After the DRA Reports were mailed, a series of telephone communications and personal meetings in San Franciso between DRA and Sierra Pacific were held which narrowed issues and addressed possible settlement on an issue-by-issue basis. As is reflected further in this Stipulation, Sierra Pacific accepted many of DRA's recommendations thereby effectively consenting to DRA's position on such issues.

The parties hereto urge that this Stipulation be adopted by the Commission. The parties believe it is clearly in the public interest. The Stipulation represents a resolution that is fair and reasonable for both Sierra Pacific and its California customers. It does so in a manner that alleviates the need for major commitment of time and resources that would otherwise be devoted to litigating the case in full.

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III

Stipulation

It is understood and agreed to by DRA and Sierra Pacific that this Stipulation is made for the purposes of expediting hearings and a decision in this case. Neither DRA nor Sierra Pacific expressly concede the validity of the other's proposed test year estimates where those estimates differ except as may be expressly noted herein. Both parties, however, desire a full settlement of all issues within the scope of this Stipulation. Both parties agree that this Stipulation, either in whole or in part, shall have no precedential effect in any future proceeding, unless specifically agreed to by the parties.

The amounts shown in this Stipulation, accompanying schedules and recommendation to the Commission are calculated using a rate of return on rate base (ROR) of 10.34% as approved in Decision No. 89-11-068, and reflect primarily the impact of adjustments for the company's new general office building (GOB), special early retirment program (SERP) and updated construction budget.

All costs and revenues are expressed in 1990 dollars unless otherwise specified.

Rate changes resulting from this proceeding shall be effective on August 1, 1990, coincident with rate changes resulting from Sierra Pacific's current ECAC/ERAM proceeding, Application Nos. 89-08-044 and 89-08-046.

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APPENDIX A

A. OPERATING REVENUES

For purposes of this Stipulation, the parties agree that the California jurisdictional operating revenues for the 1990 Test Year for Sierra Pacific shall be $23,827,000 based on California jurisdictional sales of ~~420,767~~ 429,015 MWh. This revenue requirement represents a decrease of $1,699,000 from revenues at present rates. Such revenue levels exclude revenues from all surcharges to clear balancing accounts and therefore reflect solely general rate revenues.

B. OPERATION AND MAINTENANCE EXPENSES

For purposes of this Stipulation, the parties agree that the amount of Operations and Maintenance expenses that Sierra Pacific should be allowed to recover in rates for the 1990 Test Year for its California operations is $9,355,000 before revenue adjustment. Appendix C, attached to this Stipulation, details on an account-by-account basis the operating and maintenance expense levels agreed to by the parties.

C. DEPRECIATION EXPENSE

For purposes of this Stipulation, the parties have updated the depreciation expense consistent with agreed upon plant in service. On this basis, Appendix D, attached to this Stipulation reflect an annual level of depreciation expense for the 1990 Test Year of $3,025,000.

D. TAXES

For purposes of this proceeding, the parties agree that the

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tax deductions and credits in this proceeding were computed in accordance with the normalization requirements of the Internal Revenue Code, including their effect on accelerated tax depreciation. Where applicable, federal income tax (FIT) deductions and credits were computed in accordance with the provisions of the Internal Revenue Code as amended from time to time. Further, the parties agree to utilization of the interest synchronization method of computing interest expense for purposes of calculating federal income taxes. The annual level of taxes other than income for the Test Year 1990 is $1,521,000 and total income taxes are $2,316,000.

E. RATE BASE

For purposes of this Stipulation the parties agree that the jurisdictional rate base for the 1990 Test Year is $62,961,000. The components of Rate Base are set forth in Appendix E.

F.. RATE OF RETURN

For purposes of this Stipulation, the parties agree to use the Capital Structure and ROR which was approved by the Commission in Decision No. 89-11-068.

G. MARGINAL COST, REVENUE ALLOCATION AND RATE DESIGN

For purposes of this Stipulation, DRA and Sierra Pacific agree to the resolution of the following differences between their independently developed positions. Rates will be developed for implementation in this case by applying the Marginal Cost, Revenue Allocation and Rate Design methodologies of Sierra Pacific as set forth in the Application, but as

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modified below, subject to the final sales revenue constraint established in the revenue requirements portion of this proceeding. The Parties propose to set forth the rates in a late-filed exhibit.

1. For purposes of both Marginal Cost and Rate Design analysis, sales forecasts and billing determinants consistent with the stipulated ERAM and ECAC billing factors as shown on Late Filed Exhibit 23 in Sierra Pacific's ECAC proceeding (Application No. 89-08-046) and substantially consistent with recommendations of DRA witness Lane will be used. MWH sales and billings determinants are summarized in attached Appendix F. PROMOD production costing results consistent with the ECAC stipulation will also be used.

2. Marginal Energy Cost calculations will be modified, to eliminate A&G expenses, and fixed production O&M expenses will be developed from the PROMOD results consistent with the ECAC stipulation.

3. Marginal Customer Costs will be calculated to reflect the revised customer counts proposed by DRA. Marginal customer costs for lighting services will be separated into a component representing marginal customer costs related to similar services provided to all other customer classes, and a component representing marginal costs of the facilities and services specific to lighting service.

4. Marginal Generation and Transmission Demand Costs will be calculated using the demand allocators proposed by Sierra

Pacific. Sierra Pacific will explore alternative allocation methodologies prior to its next General Rate Application filing. In particular, Sierra Pacific will explore implementation of the weighted coincident/non-coincident (C/NC) demand allocation methodology recommended by DRA.

5. As recommended by DRA, the minimum distribution system methodology used by Sierra Pacific to identify distribution costs specific to the Residential and A-1 classes will be abandoned in calculating Marginal Distribution Demand Costs. In developing marginal distribution demand costs per kW, no distinction across classes will be made, and only transformer, meter and services drop costs included in marginal customer costs will be deducted from distribution investment. The demand allocator proposed by Sierra Pacific will be used for this proceeding. As with other demand costs, Sierra Pacific will explore alternative allocation methods, including DRA's proposed C/NC allocation methodology, prior to its next General Rate Application.

6. As proposed by DRA, Voltage and Transformer Adjustments for A-2 and A-3 customers will be calculated as adjustments to class marginal costs, although not specifically to marginal demand costs. Rates within these two classes will be calculated so that the class revenue targets will be achieved after application of the existing V&T and power factor adjustments. Sierra Pacific will investigate the appropriate form and magnitude of rate differentials for different voltage

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levels and transformer ownership prior to its next General Rate Application.

7. In applying the EPMC reconciliation from marginal costs to revenue requirements, the marginal cost of facilities and services specific to lighting fixtures will be excluded. These costs will be directly included in the revenue requirements for street and outdoor lighting with no reconciliation adjustment in this proceeding and in future Sierra Pacific General Rate Applications. Sierra Pacific will add language to its Street and Outdoor Lighting Tariff to specifically indicate that customer-owned lighting applications will be served under the appropriate residential or commercial metered accounts of customers owning their own lighting equipment.

8. As recommended by DRA, demand charges for the A-3 class will be designed with a structure of separate Winter On-Peak, Summer On-Peak and Winter Mid-Peak demand charges to recover marginal generation and transmission demand costs; and a $2.00/kW non-TOU demand charge will be applied to current month maximum demand to recover a portion of the marginal distribution demand costs. The balance of distribution demand costs will be recovered by appropriate proportional adjustments to energy rates.

9. As proposed by DRA, customer charges for Rate Schedules A-1 and PA will be set at $5.00/Mo., and the customer charge for Rate Schedule A-3 will be set at $200.00/Mo.

10. The residential tier differential (as defined in

APPENDIX A

Chapter 5 of DRA's Exhibit) will be reduced by 25%. The residential baseline rate will be reduced by the customer charge revenues of permanent but not non-permanent customers. The baseline allowances, as proposed by DRA (see Table 5-2) will serve as a target and be implemented via annual filings consistent with the current practice before the Commission.

11. A-2 demand and energy charges will be set using DRA's rate design methodology.

12. Before its next General Rate Application, Sierra Pacific will explore, in addition to other possible improvements to its marginal demand cost calculations, the C/NC demand allocation proposed by DRA.

13. Before its next General Rate Application, Sierra Pacific will review its costing/rating period definitions for possible changes, including, but not limited to: seasonal assignment of months to winter, summer or (potentially) shoulder periods; and hourly definitions of on, off and mid-peak periods for weekends and holidays.

14. In its next General Rate Application, Sierra Pacific will include the agricultural irrigation class in its marginal cost study, using the most appropriate load data available for these, or similar customers. In future cases, Sierra Pacific will identify the difference between cost based irrigation rates and any proposed continuation of the existing non-cost based irrigation rates.

15. Before its next General Rate Application, Sierra

Pacific will study alternatives to providing a cost-based customer-owned streetlighting option that will provide municipalities a competitive alternative to utility-owned systems.

H. ACCOUNTING CHANGE

For purposes of this Stipulation, the parties agree that for purposes of establishing rates in California, the rate base and associated depreciation expense applicable to the Washoe Hydroelectric Plant will be removed from cost of service. Sierra Pacific does not propose to transfer the Washoe Hydro rate base balance from plant to a deferred debit account and accumulate AFUDC on that balance. The portion of rate base which would be so allocable to California jurisdiction is approximately $50,600 thereby making the separate booking and tracking of AFUDC more troublesome than the benefit to be derived therefrom.

I. ATTRITION

DRA and Sierra Pacific agree in principle on the content of the filings for Attrition Years 1991 and 1992. The Parties propose to submit a Late-Filed Exhibit containing the basis and format for the speific attrition calculation.

IV

Terms and Conditions

A. PRECEDENTIAL EFFECT

Except as specifically noted above, no agreement by Sierra Pacific or DRA to stipulate to any level of cost recovery for

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Sierra Pacific herein shall imply any agreement by any party to any principle, methodology or fact, and no part of this Stipulation shall have any precedential value in any proceeding.

B. INDIVISIBILITY OF DECISION

This Stipulation represents a compromise of many positions and interests of the parties hereto, and no individual term is assented to by any party except in consideration of the other party's assent to all of the other terms of this Stipulation. The Stipulation is accordingly indivisble, and each part is interdependent on each and all of the other parts. Any party may withdraw from this Stipulation if the Commission modifies, deletes or adds to any term. The parties agree, however, to negotiate with regard to any Commission-ordered changes in good faith to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiation is unsuccessful.

C. EVIDENTIARY EFFECT OF STIPULATION

No portion of this Stipulation, or any of its terms or conditions, or any of the discussions leading to it, may be used in hearings in support of or in opposition to any party or position without the prior express written consent of all parties hereto.

D. EFFECTUATION OF STIPULATION

The parties agree to take all actions and perform all agreements required or implied hereunder diligently in good faith, including, but not necessarily limited to, the execution of any other documents required to effectuate the terms of this Stipulation, and the preparation of exhibits for and presentation of witnesses at the hearings which may be necessary in order to obtain timely approval and adoption of this Stipulation by the Commission. Time is of the essence in this Stipulation and the parties urge the Commission to issue a final decision in time for rates to be made effective on August 1, 1990, to be coincident with ECAC/ERAM rate changes flowing from Docket Nos. 89-08-044 and 89-08-046.

E. ENTIRETY OF STIPULATION

This Stipulation contains the entire agreement of the parties hereto. The terms and conditions of the Stipulation may only be modified by a writing subscribed by all parties which specifically indicates it is intended to be a modification of this Stiplation.

F. MODIFICATION

The parties agree that they shall not file any application

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APPENDIX A

to modify any term of this Stipulation which would take effect during the 1990 Test Year without prior agreement of all parties hereto.

DATED THIS 15TH DAY OF MARCH, 1990.

SIERRA PACIFIC POWER COMPANY
Applicant

By ______________________
James D. Salo
General Counsel
Attorney for Sierra Pacific
Power Company

DIVISION OF RATEPAYER
ADVOCATES

By ______________________
Alberto Guerrero
Staff Counsel
Attorney for the Division of
Ratepayer Advocates

APPENDIX A

Sierra Pacific Power Company
California Electric
Summary Of Earnings At Proposed Rates
Test Year 1990
(000$)

LN #	DESCRIPTION	As Stipulated	As Filed	Filed Exceeds Stipulated $	Filed Exceeds Stipulated %
	Operating Revenue				
1	Sales Revenue	$22,128	24,303	2,175	9.83%
2	Other Operating Revenue	360	360	0	0.00%
3	Revenue Credits	185	185	0	0.00%
4	Total Operating Revenue	22,672	24,848	2,175	9.60%
	Operating Expense				
5	O&M Expense	9,355	10,340	985	10.53%
6	Depr & Amort Expense	3,025	3,043	19	0.61%
7	Taxes Other Than Income	1,521	1,793	272	17.88%
8	Deferred Income Taxes	713	668	(45)	-6.26%
9	Amortization of ITC	(158)	(159)	(1)	0.44%
10	Chgs Equivalent To ITC	0	0	0	0.00%
11	Federal Income Taxes	1,161	1,541	380	32.71%
12	CCFT	600	644	44	7.31%
13	Total Operating Expenses	16,217	17,870	1,654	10.20%
11	Operating Income	6,456	6,978	522	8.08%
	Adj to Operating Income	55	0	(55)	-100.00%
14	Adj Operating Income	6,511	6,978	467	7.17%
15	Weighted Average Plant	101,459	102,682	1,223	1.21%
16	Weighted Average Provision	30,723	31,224	501	1.63%
17	Net Plant	70,737	71,458	722	1.02%
18	Plus: Materials & Supplies	1,507	1,514	7	0.45%
19	Prepayments	217	216	(1)	-0.23%
20	Cash Working Capital	865	804	(61)	-7.09%
21	CWC Adjustments	(26)	(24)	1	-5.49%
22	Less: Cust Adv For Const	1,016	1,016	0	0.00%
23	Accum Def Income Tax	8,693	8,759	66	0.75%
24	Accum Def ITC	74	75	0	0.54%
25	Reserve Balances	555	560	5	0.94%
26	Rate Base	62,961	63,558	597	0.95%
27	Rate Of Return	10.34%	10.98%		0.64%

APPENDIX A

Sierra Pacific Power Company
California Electric
Summary Of Change in Revenue Requirement
Test Year 1990
(000$)

LN #	DESCRIPTION	As Stipulated	As Filed	Filed Exceeds Stipulated $	Filed Exceeds Stipulated %
	Operating Revenue				
1	Sales Revenue	(1,699)	1,539	3,238	-190.57%
2	Other Operating Revenue	0	0	0	0.00%
3	Revenue Credits	0	0	0	0.00%
4	Total Operating Revenue	(1,699)	1,539	3,238	-190.57%
	Operating Expense				
5	O&M Expense	(4)	6	9	-254.10%
6	Depr & Amort Expense	0	0	0	0.00%
7	Taxes Other Than Income	(29)	26	54	-188.71%
8	Deferred Income Taxes	0	0	0	0.00%
9	Amortization of ITC	0	0	0	0.00%
10	Chgs Equivalent To ITC	0	0	0	0.00%
11	Federal Income Taxes	(563)	468	1,031	-183.08%
12	CCFT	(17)	140	157	-928.88%
13	Total Operating Expenses	(612)	639	1,251	-204.33%
11	Operating Income	(1,087)	900	1,987	-182.82%
	Adj to Operating Income	0	0	0	0.00%
14	Adj Operating Income	(1,087)	900	1,987	-182.82%
15	Rate Base	54	(48)	(101)	-189.17%

Sierra Pacific Power Company
California Electric
Summary Of Earnings At Present Rates
Test Year 1990
(000$)

LN #	DESCRIPTION	As Stipulated	As Filed	Filed Exceeds Stipulated $	Filed Exceeds Stipulated %
	Operating Revenue				
1	Sales Revenue	23,827	22,764	(1,063)	-4.46%
2	Other Operating Revenue	360	360	0	0.00%
3	Revenue Credits	185	185	0	0.00%
4	Total Operating Revenue	24,372	23,309	(1,063)	-4.36%
	Operating Expense				
5	O&M Expense	9,359	10,335	976	10.43%
6	Depr & Amort Expense	3,025	3,043	19	0.61%
7	Taxes Other Than Income	1,550	1,767	217	14.03%
8	Deferred Income Taxes	713	668	(45)	-6.26%
9	Amortization of ITC	(158)	(159)	(1)	0.44%
10	Chgs Equivalent To ITC	0	0	0	0.00%
11	Federal Income Taxes	1,724	1,073	(651)	-37.76%
12	CCFT	617	504	(113)	-18.31%
13	Total Operating Expenses	16,829	17,232	402	2.39%
11	Operating Income	7,543	6,077	(1,465)	-19.43%
	Adj to Operating Income	55	0	(55)	-100.00%
14	Adj Operating Income	7,598	6,077	(1,520)	-20.01%
15	Weighted Average Plant	101,459	102,682	1,223	1.21%
16	Weighted Average Provision	30,723	31,224	501	1.63%
17	Net Plant	70,737	71,458	722	1.02%
18	Plus: Materials & Supplies	1,507	1,514	7	0.45%
19	Prepayments	217	216	(1)	-0.23%
20	Cash Working Capital	812	852	40	4.92%
21	CWC Adjustments	(26)	(24)	1	-5.49%
22	Less: Cust Adv For Const	1,016	1,016	0	0.00%
23	Accum Def Income Tax	8,693	8,759	66	0.75%
24	Accum Def ITC	74	75	0	0.54%
25	Reserve Balances	555	560	5	0.94%
26	Rate Base	62,908	63,606	698	1.11%
27	Rate Of Return	12.08%	9.56%		-2.52%

Appendix F

CAL_STIP

A.89-08-027, I.90-02-007

APPENDIX A

COST OF SERVICE AND RATE DESIGN

SUMMARY OF BILLING DETERMINANTS
1990 TEST PERIOD ENDING IN DECEMBER

Rate Class	MWH Sales	KW Demands	Bills	Other Categories		
Residential						
D-1						
Baseline	81,591					
Excess	137,784			Permanent Bills	Non-Permanent Bills	
Total D-1	219,375		412,759	209,175	203,584	
DM-1						
Baseline	2157					
Excess	782					
Total DM-1	2,939		1,951	1,844	106	
DS-1						Submetered Credit Units
Baseline	2,157					
Excess	324					
Total DS-1	2,481		421	342	79	10,224
Total Residential	224,795		415,131	211,361	203,770	
Small Commercial (A-1)	88,922		59,040			
Medium Commercial (A-2)						
Winter		105,893				
Summer		50,212				
Total A-2	50,665	156,105	2,040			
Large Commercial (A-3)						
Winter On-peak	7,714	78,141				
Winter Mid-peak	21,029	134,771				
Winter Off-peak	16,810					
Summer On-peak	9,153	40,651				
Summer Off-peak	8,368					
Total A-3	63,074	253,563	276	Non-TOU Billing Demands	189,882	

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Appendix F

CAL_STIP

COST OF SERVICE AND RATE DESIGN

SUMMARY OF BILLING DETERMINANTS
1990 TEST PERIOD ENDING IN DECEMBER

Rate Class	MWH Sales	KW Demands	Bills	Other Categories: Number of Lights by Sub-Category — Fixtures	Special Facilities — New Wood	Special Facilities — New Metal	Special Facilities — Underground	Special Facilities — Total Spec
Irrigation (PA)								
Summer	239							
Winter	11							
Total PA	250		60					
Lighting								
Street Lights								
5800 LU	24			70	2			2
9500 LU	189			385	55	61	51	167
16000 LU								
22000 LU	177			187	32	23	22	77
Total St	391			642	89	84	73	246
Night Guards								
5800 LU	292			839	112			112
9500 LU	439			892	183		3	186
16000 LU	179			223	63			63
22000 LU	7			7	1			1
Total OLS	917			1,961	359	0	3	362
Total All Schedules	~~428,823~~ 429,015							

Appendix F
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(END OF APPENDIX A)

Sierra Pacific Residential Rate Design Workpapers

Table 5-1

Division of Ratepayer Advocates

Residential Rates
for Sierra Pacific Power Company

Ln no	Schedule/Component	Present Rates	Proposed Rates	Percent Change
		\$/mo, \$/kwh,	\$/unit/mo	
1	D-1/DM-1			
2	Customer Charge	\$2.00	\$3.00	50.0%
3	Baseline	0.06732	0.06394	-5.0%
4	Tier 1 Non-Permanent	0.08841	0.09302	5.2%
5	Tier 2 (1)	0.10223	0.09302	-9.0%
6				
7	DS-1			
8	Customer Charge	\$2.00	\$3.00	50.0%
9	Baseline	0.06732	0.06394	-5.0%
10	Tier 1 Non-Permanent	0.08841	0.09302	5.2%
11	Tier 2 (1)	0.10223	0.09302	-9.0%
12				
13	Submetering Credit (2)		\$0.00	50.0%

(1) The proposed tier 2 rate applies to all non-permanent sales, as well as permanent sales in excess of baseline allowances.

(2) Under present and proposed tariffs, the customer charges fully compensate DS-1 customers. That is, no additional per unit credit is necessary.

Sierra Pacific Residential Rate Design Workpapers

Table 5-2

Division of Ratepayer Advocates

Present and Proposed Baseline Allowances
for Sierra Pacific Power Company

	CURRENT		TARGET		CHANGE		% CONSOLIDATION FACTOR (a)			% CUST/
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	# CUST	CLASS (b)
BASIC Permanent	300	400	330	420	10%	5%	84%	63%	9891	56.8%
Non-permanant	200	250							8947	
DM-1 Perm	240	320	145	188	-39%	-41%	44%	45%	613	
DM-1 Non-perm	160	200								
DS-1 Perm	300	400	145	188	-52%	-53%	44%	45%	786	
DS-1 Non-perm	200	250								
SPACE HEAT Perm	500	1250	500	1060	0%	-15%	78%	80%	209	1.2%
Non-permanant	350	1250							186	
DM-1 Perm	400	810	321	551	-20%	-32%	64%	52%	10	
DM-1 Non-perm	280	810								
DS-1 Perm	500	1250	321	551	-36%	-56%	N/A	N/A	N/A	
DS-1 Non-perm	350	1250								
BASIC+WATER Perm	300	400	330	420	10%	5%	45%	45%	4218	24.2%
Non-permanant	200	250							4565	
DM-1 Perm	240	320	145	188	-39%	-41%	44%	45%	75	
DM-1 Non-perm	160	200								
DS-1 Perm	300	400	145	188	-52%	-53%	44%	45%	86	
DS-1 Non-perm	200	250								
SPACE+WATER Perm	500	1250	500	1060	0%	-15%	57%	67%	2917	16.7%
Non-permanant	350	1250							3071	
DM-1 Perm	400	810	321	551	-20%	-32%	64%	52%	55	
DM-1 Non-perm	280	810								
DS-1 Perm	500	1250	321	551	-36%	-56%	N/A	N/A	N/A	
DS-1 Non-perm	350	1250								

(a) For DM-1 and DS-1, equals ratio of weighted average DM/DS usage to weighted average D-1 usage.

(b) Relative to average recorded permanent customers.

Sierra Pacific Residential Rate Design Workpapers

Table 5-3

Division of Ratepayer Advocates

Low-Income Rate Assistance (LIRA) Worksheet
for Sierra Pacific Power Company

	Rate (a)	Sales/Bills (b)	Revenue Shortfall
Customer Charge	$2.55	12,975 Cust-Mos.	$5,839
Average Energy rate	$0.06975	9,163 MWh	$112,142
Total	$0.07336	9,163 MWh	
Administrative Cost (c)			$15,700
Total LIRA Revenue Requirement :			$133,681
Total Forecasted Sales		428,558 MWh	
Les LIRA Sales		(9,163)	
SL		(352)	
Surcharge	$0.00032	419,043	

(a) 15% discount per D.89.-09-044.
(b) Eligible customers and participation rates per D.89-09-044.
(c) Administrative Cost per D.89-09-044.

Table 5-4

Division of Ratepayer Advocates

Commercial Rates
for Sierra Pacific Power Company

Ln no	Schedule/Component	Present Rates $/mo, $/kw, $/kwh	Proposed Rates	Percent Change
1	Small Commercial: A-1			
2	Customer Charge	$3.00	$5.00	66.7%
3	Energy Rate	0.09036	0.07382	-18.3%
4				
5	Medium Commercial: A-2			
6	Customer Charge	$25.00	$50.00	100.0%
7	Winter On Peak Demand Charge	$4.89	$6.71	37.3%
8	Summer On Peak Demand Charge	$6.45	$9.00	39.5%
9	Energy Rate	0.06790	0.04749	-30.1%
10				
11	Large Commercial: A-3			
12	Customer Charge	$100.00	$200.00	100.0%
13	Winter On Peak Demand Charge	$10.65	$3.44	-67.7%
14	Winter Mid Peak Demand Charge		$2.85	
15	Summer On Peak Demand Charge	$7.85	$7.65	-2.5%
16	Maximum Demand Charge		$2.00	
17				
18	Energy Rates			
19	Winter - On Peak	0.06449	0.04491	-30.4%
20	Mid Peak	0.05735	0.04464	-22.2%
21	Off Peak	0.04661	0.03716	-20.3%
22	Summer - On Peak	0.06449	0.04346	-32.6%
23	Off Peak	0.04661	0.03711	-20.4%
24				
25	Interruptible Irrigation: PA			
26	Customer Charge	$3.00	$5.00	66.7%
27	Irragation Energy Energy Rate	0.04440	0.04151	-6.5%

Late Filed Exhibit 14

Summary of Lighting Rates

Lamp Type	Kwh/Mo.	Facilities: Total Fixture	Facilities: New Wood	Facilities: New Metal	Facilities: Underground	Customer: Total Fixture	Energy & Demand
Street Lights High Pressure Sodium							
5800 LU 70 W	29	$4.92	$2.79	$8.50	$1.07	$1.08	$1.23
9500 LU 100 W	41	4.96	2.79	8.50	1.07	1.08	1.74
16000 LU 150 W	59	5.16	2.79	8.50	1.07	1.08	2.50
22000 LU 200 W	79	5.41	2.79	13.30	1.07	1.08	3.35
Night Guards							
5800 LU 70 W	29	$3.65	$2.79	$8.50	$1.07	$0.57	$1.31
9500 LU 100 W	41	3.84	2.79	8.50	1.07	0.57	1.85
16000 LU 150 W	67	3.89	2.79	8.50	1.07	0.57	3.03
22000 LU 200 W	85	4.13	2.79	13.30	1.07	0.57	3.84

(END OF APPENDIX B)

APPENDIX C

Sierra Pacific Power Company
California Electric
Revenue Requirements for Attrition Year 1991
($000)

Late Filed
Exhibit 15
Page 1 of 12

Line No	1 Description	2 Labor	3 Non-Labor	4 Other	5 Total
	O&M Expense				
1	Base for TY1990 in 1990$ (Adopted)	5,218	3,866	276	9,360
2	Other Adjustments (1)	0	0	0	0
3	Total Base for TY1990 in 1990$	5,218	3,866	276	9,360
4	1990 Escalation (Estimated)	3.50%	3.47%	0.00%	
5	1990 Escalation (Updated)	3.50%	3.47%	0.00%	
6	1991 Escalation (Estimated)	4.00%	4.90%	0.00%	
7	Base for AY1991 in 1991$	5,427	4,055	276	9,758
8	Escalation for AY1991 in 1991$	209	189	0	398
9	Uncollectible & Franchise Fee Factor	1.0191	1.0191	1.0191	
10	Change in Revenue Requirement	213	193	0	406

11 (1) Potential increase in postal rates.

Sierra Pacific Power Company
California Electric
Revenue Requirements for Attrition Year 1991
($000)

Line No	1 Description	2 AY1991
	Depreciation Expense	
1	Depreciation Expense TY1990	(3,025)
2	Depreciation Expense AY1991	3,133
3	Increase (Decrease)	107
4	Net to Gross Multiplier (Adopted in GRC)	1.562090
5	Change in Revenue Requirement	168
	Ad Valorem Taxes	
6	Ave NV Ad Valorem Tax Rate (Adopted in GRC)	0.561%
7	Increase in EOY Plant in Service (NV) TY1990 to AY1991	2,538
8	Increase (Decrease) NV Ad Valorem Taxes	14
9	Ave CA Ad Valorem Tax Rate (Adopted in GRC)	0.959%
10	Increase in EOY Plant in Service (CA) TY1990 to AY1991	1,112
11	Increase (Decrease) CA Ad Valorem Taxes	11
12	Increase (Decrease) Total Ad Valorem Taxes	25
13	Uncollectible & Franchise Fee Factor	1.0191
14	Change in Revenue Requirement	25

APPENDIX C

Sierra Pacific Power Company
California Electric
Revenue Requirements for Attrition Year 1991
($000)

Late Filed
Exhibit 15

Line No	1 Description	2 AY1991
	State Tax Depreciation	
1	State Tax Depreciation Expense TY1990	(3,904)
2	State Tax Depreciation Expense AY1991	4,042
3	Increase (Decrease) in State Tax Depr	138
4	Increase (Decrease) in CCFT @ 9.00%	(12)
5	Increase (Decrease) in FIT @ 34.00%	4
6	Increase (Decrease) in State & Federal Tax	(8)
7	Net to Gross Multiplier (Adopted in GRC)	1.562090
8	Change in Revenue Requirement	(13)
	Federal Tax Depreciation	
9	Federal Tax Depreciation Expense TY1990	(5,068)
10	Federal Tax Depreciation Expense AY1991	5,174
11	Increase (Decrease) in Federal Tax Depr	106
12	Increase (Decrease) in Federal Tax @ 34.00%	(36)
13	Net to Gross Multiplier (Adopted in GRC)	1.562090
14	Change in Revenue Requirement	(56)

APPENDIX C

Sierra Pacific Power Company
California Electric
Revenue Requirements for Attrition Year 1991
($000)

Late Filed
Exhibit 15

Line No	1 Description	2 AY1991
1	Wtd Ave Rate Base for TY1990 (Adopted in GRC)	62,961
	Plant in Service (Adopted in GRC)	
2	Wtd Ave Additions for TY1990	(2,495)
3	Net Additions for TY1990	5,899
4	Wtd Ave Additions for AY1991	911
	Depreciation Reserve (Adopted in GRC)	
5	Wtd Ave Depreciation Reserve for TY1990	30,722
6	Wtd Ave Depreciation Reserve for AY1991	(33,592)
	Taxes Deferred (Adopted in GRC)	
7	Wtd Ave Deferred Taxes for TY1990	8,758
8	Wtd Ave Deferred Taxes for AY1991	(9,514)
	Deferred ITC (Adopted in GRC)	
9	Wtd Ave Deferred ITC for TY1990	74
10	Wtd Ave Deferred ITC for AY1991	(69)
11	Wtd Ave Rate Base for AY1991 (Adopted in GRC)	64,054

APPENDIX C

Sierra Pacific Power Company
California Electric
Revenue Requirements for Attrition Year 1991
($000)

Line No	1 Description	2 AY1991
	Long-term Debt	
1	Wtd Cost of Debt TY1990 (D. 89-11-068)	4.32%
2	Wtd Cost of Debt AY1991 (D. 90-00-000)	4.32%
3	Increase (Decrease) in Debt Cost AY1991	47
4	Uncollectible & Franchise Fee Factor	1.0191
5	Change in Revenue Requirement	48
	Preferred Stock	
6	Wtd Cost of Pref. Stock TY1990 (D. 89-11-068)	0.51%
7	Wtd Cost of Pref Stock AY1991 (D. 90-00-000)	0.51%
8	Increase (Decrease) in Pref Stock Cost AY1991	6
9	Net to Gross Multiplier (Adopted in GRC)	1.562090
10	Change in Revenue Requirement	9
	Common Equity	
11	Wtd Cost of Common Equity TY1990 (D. 89-11-068)	5.51%
12	Wtd Cost of Common Equity AY1991 (D. 90-00-000)	5.51%
13	Increase (Decrease) in Common Equity Cost AY1991	60
14	Net to Gross Multiplier (Adopted in GRC)	1.562090
15	Change in Revenue Requirement	94

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Line No	1 Description	2 AY1991
	O&M Expense:	
1	Labor Escalation	213
2	Non-Labor Escalation	193
3	Other	0
4	Total O&M Expense	406
	Capital Related Items	
5	Book Depreciation	168
6	Ad Valorem Taxes	25
7	State Tax Depreciation	(13)
8	Federal Tax Depreciation	(56)
9	Debt Cost	48
10	Preferred Stock Cost	9
11	Common Equity Cost	94
12	Total Capital Related Items	274
13	Additional Revenue Requirement TY1991	680

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Line No	1 Description	2 Labor	3 Non-Labor	4 Other	5 Total
	O&M Expense				
1	Base for AY1992 in 1991$ (Adopted)	5,427	4,055	276	9,758
2	Other Adjustments (1)	0	0	0	0
3	Total Base for AY1992 in 1991$	5,427	4,055	276	9,758
4	1990 Escalation (Updated)	3.50%	3.47%	0.00%	
5	1990 Escalation (Actual)	3.50%	3.47%	0.00%	
6	1991 Escalation (Estimated)	4.00%	4.90%	0.00%	
7	1991 Escalation (Updated)	4.00%	4.90%	0.00%	
8	1992 Escalation (Estimated)	4.00%	5.20%	0.00%	
9	Base for AY1992 in 1992$	5,644	4,266	276	10,186
10	Escalation for AY1992 in 1992$	217	211	0	428
11	Uncollectible & Franchise Fee Factor	1.0191	1.0191	1.0191	
12	Change in Revenue Requirement	221	215	0	436

13 (1) Potential increase in postal rates.

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Line No	1 Description	2 AY1992
	Depreciation Expense	
1	Depreciation Expense AY1991	(3,133)
2	Depreciation Expense AY1992	3,250
3	Increase (Decrease)	117
4	Net to Gross Multiplier (Adopted in GRC)	1.562090
5	Change in Revenue Requirement	183
	Ad Valorem Taxes	
6	Ave NV Ad Valorem Tax Rate (Adopted in GRC)	0.561%
7	Increase in EOY Plant in Service (NV) AY1991 to AY1992	3,232
8	Increase (Decrease) NV Ad Valorem Taxes	18
9	Ave CA Ad Valorem Tax Rate (Adopted in GRC)	0.959%
10	Increase in EOY Plant in Service (CA) AY1991 to AY1992	1,234
11	Increase (Decrease) CA Ad Valorem Taxes	12
12	Increase (Decrease) Total Ad Valorem Taxes	30
13	Uncollectible & Franchise Fee Factor	1.0191
14	Change in Revenue Requirement	31

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Line No	1 Description	2 AY1992
	State Tax Depreciation	
1	State Tax Depreciation Expense AY1991	(4,042)
2	State Tax Depreciation Expense AY1992	4,228
3	Increase (Decrease) in State Tax Depr	185
4	Increase (Decrease) in CCFT @ 9.00%	(17)
5	Increase (Decrease) in FIT @ 34.00%	6
6	Increase (Decrease) in State & Federal Tax	(11)
7	Net to Gross Multiplier (Adopted in GRC)	1.562090
8	Change in Revenue Requirement	(17)
	Federal Tax Depreciation	
9	Federal Tax Depreciation Expense AY1991	(5,174)
10	Federal Tax Depreciation Expense AY1992	5,471
11	Increase (Decrease) in Federal Tax Depr	297
12	Increase (Decrease) in Federal Tax @ 34.00%	(101)
13	Net to Gross Multiplier (Adopted in GRC)	1.562090
14	Change in Revenue Requirement	(158)

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Line No	1 Description	2 AY1992
1	Wtd Ave Rate Base for AY1991 (Adopted in GRC)	64,054
	Plant in Service (Adopted in GRC)	
2	Wtd Ave Additions for AY1991	(911)
3	Net Additions for AY1991	3,650
4	Wtd Ave Additions for AY1992	1,780
	Depreciation Reserve (Adopted in GRC)	
5	Wtd Ave Depreciation Reserve for TY1990	33,592
6	Wtd Ave Depreciation Reserve for AY1991	(36,577)
	Taxes Deferred (Adopted in GRC)	
7	Wtd Ave Deferred Taxes for TY1990	9,514
8	Wtd Ave Deferred Taxes for AY1990	(10,258)
	Deferred ITC (Adopted in GRC)	
9	Wtd Ave Deferred ITC for TY1990	69
10	Wtd Ave Deferred ITC for AY1991	(63)
11	Wtd Ave Rate Base for AY1991 (Adopted in GRC)	65,551

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Revenue Requirements for Attrition Year 1992
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Line No	1 Description	2 AY1992
	Long-term Debt	
1	Wtd Cost of Debt AY1991 (D. 90-00-000)	4.32%
2	Wtd Cost of Debt AY1992 (D. 91-00-000)	4.32%
3	Increase (Decrease) in Debt Cost AY1992	65
4	Uncollectible & Franchise Fee Factor	1.0191
5	Change in Revenue Requirement	66
	Preferred Stock	
6	Wtd Cost of Pref. Stock AY1991 (D. 90-00-000)	0.51%
7	Wtd Cost of Pref Stock AY1992 (D. 91-00-000)	0.51%
8	Increase (Decrease) in Pref Stock Cost AY1992	8
9	Net to Gross Multiplier (Adopted in GRC)	1.562090
10	Change in Revenue Requirement	12
	Common Equity	
11	Wtd Cost of Common Equity AY1991 (D. 90-00-000)	5.51%
12	Wtd Cost of Common Equity AY1992 (D. 91-00-000)	5.51%
13	Increase (Decrease) in Common Equity Cost AY1992	82
14	Net to Gross Multiplier (Adopted in GRC)	1.562090
15	Change in Revenue Requirement	129

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Line No	1 Description	2 AY1992
	O&M Expense:	
1	Labor Escalation	221
2	Non-Labor Escalation	215
3	Other	0
4	Total O&M Expense	436
	Capital Related Items	
5	Book Depreciation	183
6	Ad Valorem Taxes	31
7	State Tax Depreciation	(17)
8	Federal Tax Depreciation	(158)
9	Debt Cost	66
10	Preferred Stock Cost	12
11	Common Equity Cost	129
12	Total Capital Related Items	245
13	Additional Revenue Requirement TY1991	681

(END OF APPENDIX C)