ATTACHMENT A

BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

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 No. A.05-06-018 (U 903 E)

JOINT MOTION TO ACCEPT SETTLEMENT AGREEMENT OF SIERRA PACIFIC POWER COMPANY, DIVISION OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, THE A-3 CUSTOMER COALITION AND WESTERN MANUFACTURED HOUSING COMMUNITY ASSOCIATON

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Pursuant to Rule 51.1 of the Commission's Rules of Practice and Procedure ("Rules"), the Division of Ratepayer Advocates ("DRA"), Sierra Pacific Power Company ("Sierra"), The Utility Reform Network ("TURN"), A-3 Customer Coalition ("A-3CC") and Western Manufactured Housing Community Association ("WMA") (hereafter, collectively, "the Parties") request that the Commission approve and adopt the Settlement Agreement entered into by and between the Parties that resolves all issues raised in Sierra's application for general rate relief and for authority to increase its electric rates and charges for electric service. The original signed Settlement Agreement is attached to this motion and has been admitted into evidence in this proceeding as Exhibit 18. Pursuant to Rule 2.2(d) of the Commission's Rules of Practice and Procedure, Sierra has been authorized to sign the Joint Motion on behalf of the Parties.

The attached Settlement Agreement reflects an agreed upon resolution of Sierra's application. This motion will explain why Commission approval of the Settlement Agreement is consistent with Rule 51.1(3) in that it is reasonable in light of the whole record, consistent with the law, and will serve the public interest and the interests of Sierra's ratepayers.

I. BACKGROUND

Sierra is an investor-owned public utility engaged in the business of generating, transmitting, and distributing electric energy in portions of eastern California and in northern Nevada. Sierra provides retail electric service to customers in Nevada, Placer, Sierra, Plumas, Mono, Alpine and El Dorado counties in eastern California.

Sierra filed an application for a general increase in rates with this Commission on June 3, 2005. In its application, Sierra requested an overall revenue requirement increase of $8.2 million, required to earn its authorized rate of return of 9.04 percent, reflecting a return on equity of 10.9 percent. This represented an overall 12.7 percent increase to Sierra's California retail customers, to become effective on January 1, 2006.

On July 8, 2005, DRA filed a protest of the application. Sierra filed a reply to DRA's protest on July 21, 2005.

On September 7, 2005, a Prehearing Conference was held. Appearances were made by DRA, Sierra, WMA, TURN, and A-3CC. The matter was set for hearings to begin on January 23, 2006. On October 7, 2005, the Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo was issued.

On or about January 13, 2006, the Parties began conducting settlement discussions. On January 18, 2006, the Parties submitted a Joint Statement of Material Facts to be Adjudicated at Hearing pursuant to the Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo. The Joint Statement indicated, however, that settlement discussions were actively ongoing, and that the Parties intended to update the Administrative Law Judge at the Prehearing conference scheduled for the next day. On or about January 19, 2006, the Parties reached a verbal agreement settling all revenue requirement issues. At the prehearing conference the afternoon of January 19th, the Parties informed the assigned administrative law judge that they had an agreement in principle on the revenue requirement issues. On January 20, 2006, the Parties finalized a verbal agreement with respect to marginal cost, revenue allocation and rate design, effectively settling all issues in the proceeding. On the afternoon of January 20, 2006, the Parties informed ALJ McKenzie that they had resolved the remaining rate design issues. The Settlement Agreement attached to this motion memorializes the settlement reached by the Parties.

II. SUMMARY OF SETTLEMENT AGREEMENT

As a result of their negotiations, the Parties have reached a settlement of all issues raised in DRA's protest, as well as issues raised by the intervenor Parties, TURN, WMA, and A-3CC. Without reciting every detail, the general components of the Settlement Agreement are as follows:

A. Revenue Requirement Issues

A number of revenue requirement issues were resolved when Sierra accepted, in its rebuttal testimony, certain adjustments proposed by DRA and TURN. (TURN did not support a higher overall revenue requirement for Sierra than DRA but instead chose to focus its participation on specific issues.) These included a $1.685 million adjustment to reflect the results of the depreciation study the company filed with the Commission on October 3, 2005; an adjustment of $580 thousand to reflect a decrease to Sierra's rate of return as a result of a recent update of the company's cost of capital trigger mechanism that reduced the return on equity from 10.9% to 9.92%: an adjustment of $262 thousand to accept DRA's forecasted distribution plant calculation; and an adjustment of $297 thousand proposed by TURN to reflect the decision of the Public Utilities Commission of Nevada ("PUCN") in Docket No. 03-12002 to disallow recovery of some of the costs of constructing the combined cycle portion of the Piñon Pine Power plant.

Among the major issues that remained in contention pending the evidentiary hearing, DRA agreed to accept TURN's proposed adjustment on the Piñon Pine plant. Sierra agreed to accept an $84 thousand adjustment reflecting the removal of the unamortized balance of generation divestiture costs from rate base. Those divestiture costs for which recovery is allowed will be amortized over eight years and will not accrue carrying charges. DRA and Sierra agreed that the company's request to recover the costs of implementation and education related to restructuring ("AB 1890") would be reduced by half resulting in an adjustment of $330 thousand. The balance will be amortized over three years and will not accrue carrying charges.

As part of the negotiated settlement by the Parties, Sierra agreed to accept a $164 thousand adjustment representing potential savings to California ratepayers as a result of the corporate reorganization undertaken in 2005. Sierra also agreed to DRA's adjustment of $123 thousand for fuel related materials and supplies and agreed to seek recovery of these expenses in the future in its subsequent ECAC proceedings. Sierra further agreed to accept half of DRA's $200 thousand adjustment related to forecasted transmission plant. With respect to Operations and Maintenance Expense ("O&M"), DRA recommended an adjustment of $1.039 million. TURN recommended a $25 thousand adjustment to charge half of directors and officer's liability insurance to shareholders. As part of the settlement, Sierra accepted an overall adjustment to O&M of $650 thousand. Finally, TURN recommended an adjustment of $25 thousand to reduce the company's rate base by a five-year average of customer deposits and an adjustment of $30 thousand to cash working capital. Sierra agreed to accept TURN's adjustment for customer deposits and TURN agreed to withdraw its adjustment to cash working capital.

As a result of the negotiated settlement, the Parties agreed that Sierra's revenue requirement should increase by $4.098 million. This amount represents roughly half of the revenue requirement requested in the application. A comparison table summarizing Sierra, DRA and TURN's positions on results of operations is attached as Exhibit A.

B. Unbundling, Marginal Cost, Revenue Reconciliation and Rate Design

Sierra proposed to unbundle all demand side management ("DSM") costs to the distribution function. The company proposed to allocate franchise taxes on a property related allocation factor and other operating revenues ("OORs") on a sales revenue basis. DRA accepted all three of Sierra's proposals. TURN proposed to unbundle $450 thousand of DSM costs to the generation function and to unbundled $643 thousand of franchise taxes based on revenue. TURN also proposed to directly assign service, reconnection and miscellaneous service charges to the distribution function with the remaining balance unbundled on a revenue allocation. Neither of the other Parties commented on these issues. As part of the negotiated settlement, TURN agreed to accept Sierra's unbundling of DSM costs and franchise taxes. Sierra and DRA agreed to accept TURN's proposal on OORs.

Sierra's proposed marginal cost study was consistent with previous Commission decisions and was accepted by DRA as filed and not opposed by A-3CC and WMA. TURN opposed portions of the marginal cost study relating to treatment of uncollectible accounts and tariffed other operating revenues (OORs). TURN also proposed a different mechanism for allocating marginal transmission and distribution demand revenues to customer classes in the revenue reconciliation process, which was partially accepted by Sierra in rebuttal. A-3CC specifically opposed TURN's reallocation of marginal transmission and distribution demand revenues. As a result of the Parties' agreement on the 3.2% revenue reconciliation cap and as part of the negotiated settlement, TURN agreed to accept Sierra's original marginal cost study for the purpose of designing rates in this proceeding. Sierra also agreed to re-evaluate the method of determining class marginal transmission and demand costs in its next General Rate Case.

Sierra originally proposed to exclude OORs from the revenue reconciliation process. After reviewing TURN's direct testimony (which made an adjustment to the marginal cost study for tariffed OORs), Sierra proposed in rebuttal to include tariffed OORs in the revenue reconciliation TURN specifically accepted Sierra's rebuttal position on including OORs in the revenue reconciliation as reasonable.

Sierra proposed reallocation of class revenue requirements based on Equal Percentage of Marginal Cost ("EPMC") with a 5% cap on increases to any class above the overall percentage increase. DRA proposed to use EPMC with a 2.5% cap and a 0% floor. TURN conditionally accepted Sierra's 5% cap. A-3CC proposed that the EPMC methodology be used with no cap on increases to any class. WMA did not take a position on this issue. As part of the negotiated settlement, the Parties agreed to use the EPMC methodology with a cap of 3.2% (which was approximately equal to TURN's uncapped results for the residential class using TURN's marginal cost study and marginal demand revenues for revenue reconciliation) and a floor of 0%.

Sierra proposed to increase the residential customer charge from $4.50 to $6.00 with a 15% composite tier differential. DRA accepted Sierra's residential rate design as filed. TURN proposed increasing the customer charge from $4.50 to $5.40 with a 20% composite differential. As part of the negotiated settlement, TURN accepted Sierra's customer charge of $6.00 and the Parties accepted a 17.5% tier differential.

C. *Master Meter Issues (DS-1)*

Sierra proposed a DS-1 Master Meter credit consistent with the Commission's decision in D.04-11-033. WMA did not object to the company's methodology but proposed to add transformer avoided costs. As part of the negotiated settlement, Sierra and WMA agreed to a calculation of the credit similar to that described in Sierra's rebuttal testimony (Exhibit 7). Sierra and WMA agreed to use the company's calculation methodology for the baseline diversity benefit adjustment ("DBA"), which will be stated on a $/permanent tenant/day basis and implemented as described in the DS-1 tariff.

Sierra and WMA further agreed to include in the submetering credit an adjustment for common area usage, which will also be stated on the $/tenant/day basis. The company will provide an estimate of common area usage in its next GRC but is not committed to support an adjustment. Finally, Sierra and WMA agreed that Sierra would implement the first of the three bill calculation service options that Sierra had analyzed for master metered customers, and will not include the costs of providing this service in the DS-1 rate schedule this time.

III. THE COMMISSION SHOULD APPROVE THE SETTLEMENT

A. Settlements Are Favored.

The Commission has expressed a strong public policy favoring settlement of disputes if the settlement is fair and reasonable in light of the record. *See Re Pacific Gas and Electric Co.* (1988) 30 C.P.U.C.2d 189, 221-223; *Re Pacific Gas* *and Electric Co.* (1991) 40 C.P.U.C.2d 301, 326. "The policy favoring settlements is intended to reduce the expense of litigation to ratepayers, conserve scarce Commission resources, and allow the Parties to avoid the risk that a litigated resolution will produce unacceptable results." *Re Southern California Edison Co.,* D. 98-02-091, 1998 WL 209288 *4(Cal.P.U.C.) (citing *Re San Diego Gas and Electric Co.* (1992) 46 C.P.U.C.2d 538, 553.

This public policy formed the basis for Commission Rule 51.1, which provides that the Commission will approve a settlement if it is (1) reasonable in light of the whole record, (2) consistent with law, and (3) in the public interest. The Parties believe that the settlement embodied in this agreement is reasonable in light of the whole record, consistent with law, and in the public interest, as required by Rule 51.1(e). It is also consistent with the Commission's policy with regard to all party settlements.

B. The Settlement Is Reasonable In Light Of The Record

An examination of the complete record of this proceeding (Exhibits 1-18) demonstrates conclusively that all of the Parties made substantial concessions to settle this case. The revenue requirement accepted by Sierra is approximately one half of the amount requested in the application. In order to drastically reduce the company's requested revenue requirement DRA was willing to make concessions on issues of vital importance to Sierra such as the Piñon Power Plant, certain restructuring costs and the corporate reorganization of 2005. For its part, TURN did not argue for a specific revenue requirement but instead focused on specific issues. Sierra accepted TURN's adjustments on Piñon and customer deposits. TURN compromised on D&O insurance as a result of the larger partial O&M disallowance primarily related to DRA's position and agreed to withdraw the cash working capital adjustments.

On unbundling, marginal cost revenue reconciliation and rate design issues, the record also reflects significant concessions by all of the Parties. DRA generally accepted Sierra's proposals on most of these issues. TURN agreed to accept Sierra's unbundling of DSM costs and franchise taxes and Sierra agreed to accept TURN's proposal on OORs. TURN also agreed to accept Sierra's marginal cost study for rate design purposes. TURN agreed to Sierra's proposed residential customer charge and Sierra and TURN essentially "split the difference" on the composite tier differential.[1]

The most contentious issue in this group of issues was reallocation of rate class revenue requirements based on EPMC with a cap on increases to any class above any overall percentage increase. All Parties supported the EPMC methodology. However, DRA proposed a 2.5% cap with no class receiving a decrease. Sierra proposed a 5% cap which TURN conditionally accepted. A-3CC proposed no cap arguing for entirely cost based rates for all classes. The Parties

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[1] The resulting residential rate design produced a win-win result, as it allowed both of the settling parties to achieve their key objectives. It raised the customer charge as proposed by Sierra in light of its concern regarding higher fixed costs and the subsidy of vacation homeowners by permanent customers. At the same time, the overall package achieved a key TURN objective of reducing the burden of the residential rate increase on permanent residents relative to vacation homes. The compromise produced approximately the same relative percentage rate increases for permanent residents and vacation homes as TURN's litigation position.

settled for a 3.2% cap with no class receiving a decrease, representing significant movement by DRA and A-3CC in the interest of achieving an all party, complete settlement of this case.

With respect to master metering issues raised by WMA, the Settlement on the master meter discount calculation uses the marginal cost method for determining the value of the avoided costs. In Decision 04-11-033, the Commission determined that the marginal cost approach was one of two acceptable methods for calculating the master meter discount, with the sampling method being the other approved calculation methodology. Further, Sierra and WMA agree, that the "replacement" or "rental" method is the appropriate method for determining the value of the avoided marginal costs applicable to master meter discount. No other Parties objected to the use of the rental method for the purpose of setting the master meter discount. The agreement on this particular aspect of the marginal cost calculation applicable to the discount is consistent with the Commission not specifying a particular marginal cost method in D.04-11-033, but to require the particulars of any specific method calculation to be addressed in the proceeding in which the discount is determined. The settling Parties agree that the final discount of $0.28257 per tenant per day[2] yields a result that is approximately the same as if master meter community residents were metered directly by the

[2] This amount is prior to the removal of the portion provided to DS-1 customers through the customer charge and is prior to the loss adjustment, the baseline diversity benefit adjustment and common area use adjustment. The final common area use adjustment and baseline diversity adjustment calculation will require the final residential and commercial rates resulting from the overall settlement.

utility. In addition, as part of the settlement on the discount, Sierra and WMA agreed to include an adjustment for common area usage in the discount, and have agreed to calculate the Baseline Diversity Benefit Adjustment (BDA) as Sierra proposed and to separately state the DBA on a $ per permanent tenant per day basis in the DS-1 tariff. Furthermore, Sierra and WMA have reached a compromise position on Sierra's offering of bill calculation services to its master meter customers. Sierra will implement its Option 1 bill calculation service, and for this case only will not charge the DS-1 class the cost identified to provide this service and will absorb these costs itself.

C. The Settlement Is Consistent With Law.

Section 451 of the Public Utilities Code requires that the rates charged by a regulated utility must be just and reasonable. Section 454 prevents an increase in a public utility's rates unless the Commission finds such an increase is justified. Section 701 confers upon the Commission the authority to supervise and regulate public utilities and to do all things necessary and convenient in the exercise of its regulatory jurisdiction.

For the reasons set forth in Paragraph B above as well as those stated in the Settlement Agreement, the Parties submit that the increase in rates that would result from implementation of the Settlement Agreement is justified. This proceeding is only the second general rate case that Sierra has filed with the Commission since 1992. Given the evidence contained in the record the increase in rates that would result if the Settlement Agreement is approved are just and reasonable.

D. The Settlement Is In The Public Interest

As a result of the Settlement Agreement, the substantial resources of all of the Parties and the Commission have been conserved by avoiding litigation of the issues. The company will receive a needed increase, but that increase will be far less than what was originally requested thanks to the efforts of the other four Parties to this proceeding. We submit that this result is in the public interest.

IV. CONCLUSION

Pursuant to Rule 51 of the Commission's Rules of Practice and Procedure, the Settlement Agreement is reasonable in light of the whole record, consistent with law and in the public interest. The Parties jointly move that the Commission issue an order approving the Settlement Agreement.

Dated this 3rd day of February, 2006.

Respectfully submitted,

By: ____________________

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ORIGINAL DOCUMENT
JANUARY 24, 2006

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	)))))	Application No. A. 05-06-018 (U 903 E)

SETTLEMENT AGREEMENT BETWEEN SIERRA PACIFIC POWER COMPANY, DIVISION OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, THE A-3 CUSTOMER COALITION AND THE WESTERN MANUFACTURED HOUSING COMMUNITIES ASSOCIATION

1. General

1.1 The Parties to this Settlement Agreement before the California Public Utilities Commission (Commission) are Sierra Pacific Power Company (Sierra), the Division of Ratepayer Advocates (DRA) (Formerly known as Office of Ratepayer Advocates, ORA), The Utility Reform Network (TURN), The A-3 Customer Coalition (A-3CC) and Western Manufactured Housing Communities Association (WMA). The Parties, desiring to avoid the expense and uncertainty attendant to litigation of the matters in dispute between them have agreed on this Settlement Agreement, which they now submit for approval.

1.2 Since this Settlement Agreement represents a compromise by them, the Parties have entered into each component of this Settlement Agreement on the basis that its approval by the Commission not be construed as an admission or concession by any Party regarding any fact or matter of law in dispute in this proceeding or in any other proceeding before the Commission. Furthermore, the Parties intend that the approval of this Settlement Agreement by the Commission not be construed as a precedent or statement of policy of any kind for or against any Party in any current or future proceeding.

1.3 The Parties agree that no signatory to this Settlement Agreement assumes any personal liability as a result of their agreement. All rights and remedies of the Parties are limited to those available before the Commission.

1.4 The Parties agree that this Settlement Agreement is an integrated agreement, so that if the Commission rejects or modifies any portion of this Settlement Agreement, each Party has the right to withdraw, renegotiate the Settlement Agreement, and/or request other relief pursuant to Commission Rule 51.7.

1.5 All issues between the Parties have been resolved.

1.6 Included in this Settlement Agreement are supporting references to Sierra's application for authority to increase its electric rates, Sierra's direct and rebuttal testimony, the Reports of DRA and TURN and the direct and rebuttal testimony of A-3CC and WMA.

2. <u>Requested Revenue Requirement</u>

In its application, Sierra requested an increase in its revenue requirement of $8.2 million representing an overall 12.7% increase to the company's retail customers to become effective on January 1, 2006. The increase requested by Sierra was requested for it to earn its authorized rate of return of 9.04% with a return on equity of 10.9% (Sierra Application, p 2).

3. Adjustment to Revenue Requirement

3.1 **Depreciation Rates** – At the direction of the Commission on October 5, 2005 Sierra filed the depreciation study in this proceeding that it had filed on October 3, 2005 with the Public Utilities Commission of Nevada (PUCN) in Docket No. 05-10004. In its report on results of operations in this proceeding, DRA proposed to reflect the depreciation rates filed with the PUCN for cost of service purposes resulting in an adjustment of $1.685 million to Sierra's revenue requirement. Sierra accepts this adjustment. DRA and TURN agree that once the PUCN issues a decision in Docket No. 05-1004, Sierra will implement the approved depreciation rates to calculate expenses and reserve for its Nevada and California jurisdictions but not adjust California electric rates until its next GRC. (DRA Report on Result of Operations, pp 11-1 to 11-3; Sierra Rebuttal on Results of Operations, pp 5-2, 5-3; TURN's Report on Results of Operations, pp 7, 8.)

3.2 **Rate of Return** – DRA proposed a reduction to Sierra's Rate of Return (ROR) calculation from 9.04% to 8.73% reflecting a decrease in Sierra's rate of return on equity from 10.9% to 9.92% as a result of the most recent update of Sierra's cost of capital trigger mechanism. DRA's proposed adjustment subtracts $580 thousand from Sierra's requested revenue requirement. Sierra agrees to DRA's adjustment. DRA also proposed that the ROR remain at 8.73% until Sierra's next GRC. As part of this Negotiated Settlement Agreement, Sierra agrees to DRA's recommendation. (DRA Report on Operations p 2-2; Sierra Rebuttal on Results of Operations, p 1-2.)

3.3 **Forecasted Distribution Plant** – DRA proposed a reduction in Sierra's forecasted distribution plant amounts of $1.6 million. This results in an adjustment of approximately $262 thousand to Sierra's requested revenue requirement. Sierra accepts this adjustment. (DRA Report of Results of Operations, p10-7; Sierra Rebuttal on Results of Operations, p 5-2.)

3.4 **Other Revenues** – DRA proposed an adjustment to increase Other Operating Revenues by $101 thousand based on a different forecasting methodology from that used by Sierra. On November 29, 2005, DRA revised its adjustment to an increase of $24 thousand. Sierra accepts this adjustment. (DRA Report of Results of Operations, p1-3; Sierra Rebuttal on Results of Operations, p 1-2.)

3.5 **Piñon Pine Project** – In its Report on Results of Operations, TURN recommended that the CPUC allow Sierra to recover the California jurisdictional portion of Sierra's construction costs for the combined cycle portion of the Piñon Pine Project to the same extent the PUCN had permitted recovery in Docket No. 03-12002, Sierra's last Nevada GRC. In Docket No. 03-12002, the PUCN disallowed recovery and rate base treatment of a substantial portion of the combined cycle costs. Sierra has appealed the PUCN's decision and its appeal is currently working its way through the Nevada courts. TURN's recommendation that the CPUC should follow the PUCN's decision on this issue results in a reduction to Sierra's revenue requirement of $297 thousand. TURN proposes that Sierra's revenue requirement be subsequently adjusted to reflect the ultimate disposition of Sierra's appeal of the PUCN decision. Sierra accepts TURN's adjustment. DRA in its Report on Results of Operations recommends that the entire California jurisdictional amount of Sierra's request to recover a portion of combined cycle construction costs be disallowed. Sierra opposed DRA's adjustment. As part of the negotiated Settlement Agreement, DRA and Sierra have agreed to accept TURN's adjustment and Sierra agrees that if it prevails in its appeal of the PUCN's decision, it will not revise rates before its next GRC. (Sierra's Direct Testimony in Support of Results of Operations, pp 6-1 to 6-6, Tables 6-1 and 6-2; TURN's Report on Results of Operation, pp 2 to 4; DRA's Report on Results of Operations, pp 5-1 to 5-13; Sierra's Rebuttal on Results of Operations, pp 4-1 to 4-4.)

3.6 **Generation Divestiture** – Sierra has requested recovery of costs incurred attempting to divest itself of most of its generation plant over an eight year amortization period. That attempt was blocked by legislation adopted in California in late 2000 and Nevada in early 2001. DRA has proposed that all of these costs be removed from Sierra's Requested Revenue Requirement, an adjustment of $174 thousand. TURN did not address this issue. As part of this negotiated Settlement Agreement Sierra has agreed to an adjustment of $84 thousand to its revenue requirement reflecting removal of the unamortized balance from ratebase. The divestiture costs will be amortized over eight years and will not accrue carrying charges. (DRA Report on Operations pp. 4-4, 4-5; Sierra Rebuttal on Results on Operations, pp 3-1, 3-2.)

3.7 **Education and Implementation Costs for AB 1890** – Sierra has sought recovery of education and implementation costs it incurred as a result of restructuring over a three year amortization period. DRA proposed to remove all of these costs from Sierra's requested revenue requirement for an adjustment of $661 thousand. As part of this negotiated Settlement Agreement Sierra and DRA agree that Sierra's request would be reduced by half resulting in an adjustment of $330 thousand. This issue will be considered fully settled by this Negotiated Settlement Agreement. (DRA Report on Results of Operations, pp 4-2 to 4-4; Sierra Rebuttal on Results of Operations, pp 2-1 to 2-3.)

3.8 **2005 and Beyond Reorganization** – DRA proposed an adjustment of $556 thousand to Sierra's revenue requirement for savings it believes Sierra will experience in test year 2006 as a result of its reorganization in 2005. Sierra contested whether any potential savings would be realized and argued in the alternative that DRA's method of calculating the savings was incorrect. As part of this negotiated settlement, Sierra agreed to accept an adjustment of $164 thousand which represents a more accurate estimate of the potential reorganization savings. (DRA's Report of Results of Operations, pp 13-3, 13-4; Sierra Rebuttal on Results of Operations, pp 2-6, 2-7.)

3.9 **Fuel Related Materials and Supplies (M&S)** – DRA recommends an adjustment of $123 thousand to Sierra's revenue requirement and recommends that all recovery of these expenses in the future occur in subsequent ECAC proceedings. As a result of this negotiated Settlement Agreement, Sierra accepts the adjustment and DRA's recommendation. (DRA's Report on Results of Operations, pp 12-2 to 12-4; Sierra Rebuttal on Results of Operations, pp 5-3, 5-4.)

3.10 **Forecasted Transmission Plant** – DRA recommends an adjustment of $200 thousand to Sierra's revenue requirement related to forecasted transmission plant. As part of this negotiated settlement, Sierra and DRA agree that the adjustment should be $100 thousand. (DRA Report on Results of Operations, p 10-6; Sierra Rebuttal on Results of Operations, pp 5-1, 5-2.)

3.11 **Operations and Maintenance Expenses (O&M), Administrative and General (A&G)** – DRA recommended adjustments totaling $1.039 million to Sierra's requested revenue requirement as a result of different forecasting methodologies for O&M and A&G expenses. TURN recommended a separate $25 thousand adjustment to charge half of the Director's and Officer's liability insurance to shareholders. Sierra opposed this adjustment. As part of this negotiated Settlement Agreement, Sierra accepts an adjustment of $650 thousand to O&M expenses. (DRA Report on Results of Operations, pp 8-1 to 8-12; TURN Report on Results of Operations, pp 4 to 5; Sierra Rebuttal on Results of Operations, pp 2-3 to 2-5.)

3.12 **Working Capital Adjustments Recommended by TURN** – TURN has recommended adjustments to Sierra's requested revenue requirement of $25 thousand to reduce rate base by a five year average of customer deposits and $30 thousand to include bonus incentive payment lag in labor lag days and remove ECAC from cash working capital (CWC). As part of this negotiated settlement, Sierra agrees to accept TURN's adjustment for customer deposits. TURN to agrees to withdraw its other adjustments for CWC. (TURN Report on Results of Operations, pp 5 to 7; Sierra Rebuttal on Results of Operations, pp 2-5, 5-5, 5-7, 5-8.)

4. <u>Settled Revenue Requirement</u>

The Parties agree that Sierra should receive an increase of $4.098 million (6.94% over total revenue) to its revenue requirement as a result of this settlement.

5. <u>Unbundling of Revenue Requirement to Functions</u>

5.1 **Demand-side Management (DSM)** – Sierra proposed to unbundle these costs to the Distribution function. TURN proposed to unbundle $450 thousand of DSM costs to the Generation function. DRA accepted Sierra's unbundling and no other party commented. As part of this negotiated Settlement Agreement, TURN agreed to accept Sierra's unbundling. (Sierra's Rebuttal on Marginal Cost of Service, Rate Design, and Master Meter Service, pp 1-6, 1-7; TURN's Report on Marginal Cost and Rate Design, pp 9,10,12 to 14.)

5.2 **Franchise Taxes** - Sierra proposed to allocate Franchise Taxes on a property related allocation factor. TURN proposed to unbundle $643 thousand of franchise related revenue requirement on a revenue basis. DRA accepted Sierra's unbundling and no other party commented. As part of this negotiated Settlement Agreement, TURN agreed to accept Sierra's unbundling. (Sierra's Rebuttal on Marginal Cost of Service, Rate Design, and Master Meter Service, pp 1-6, 1-7; TURN's Report on Marginal Cost and Rate Design, pp 12 to 14.)

5.3 **Other Operating Revenue (OOR's)** – Sierra allocated OOR's on a sales revenue basis. TURN proposed to directly assign service, reconnection and miscellaneous service charges to the distribution function with the balance remaining on a revenue allocation. DRA accepted Sierra's unbundling and no other party commented.

Sierra agreed to TURN's unbundling adjustment. (Sierra's Rebuttal on Marginal Cost of Service, Rate Design, and Master Meter Service, pp 1-6,1-7; TURN's Report on Marginal Cost and Rate Design, pp 12 to 14.)

6. **Marginal Cost**

Sierra's proposed Marginal Cost study was filed consistent with past Sierra CPUC Orders on June 3, 2005. TURN opposed various aspects of the marginal cost of service study, including treatment of uncollectible expense, energy conservation costs, working capital loading factor, and the determination of class transmission and distribution marginal revenues. DRA accepted Sierra's Marginal Cost of Service Study as filed and A-3CC and WMA did not oppose. As part of this negotiated Settlement Agreement and in light of the revenue reconciliation cap, TURN agreed to accept Sierra's Marginal Cost Study as filed for purposes of designing rates in this case. (Sierra's Rebuttal on Marginal Cost of Service, Rate Design, and Master Meter Service, pp 2-1 to 2-9; TURN's Report on Marginal Cost and Rate Design, pp 2 to 11,14 to 16.)

7. **Revenue Reconciliation**

7.1 **Other Operating Revenue (OOR's)** – Sierra's proposed revenue reconciliation of OOR's reduced Sales Revenue Requirement by OOR's. TURN recommended reducing marginal customer accounting (MCA) costs and allocation of OOR's to classes in proportion to the reduced MCA. In its Rebuttal, Sierra rejected TURN's adjustment to marginal cost, but proposed allocating OOR's as a credit directly to classes in the revenue reconciliation process. As part of this negotiated Settlement Agreement, TURN agreed to accept Sierra's Rebuttal position to allocate OOR's in the reconciliation process and to accept Sierra's Marginal Cost Study as filed. (Sierra's Rebuttal on Marginal Cost of Service, Rate Design, and Master Meter Service, p 1-4; TURN's Report on Marginal Cost and Rate Design, p 9.)

7.2 **Constraints on Cost Based Allocation** – Sierra proposed re-allocation of class Revenue Requirements based on Equal Percentage of Marginal Cost (EPMC) constrained by a 5% increase (cap) above the overall percentage increase. DRA proposed to use EPMC limited by a 2.5% cap with no class being permitted to receive a decrease (0% floor). TURN conditionally accepted Sierra's 5% cap methodology based on TURN's filed marginal cost and unbundling study, which showed an increase above the system average to the Residential class of approximately 3.2%. A-3CC proposed that class revenue requirements be based purely on EPMC with no cap. WMA had no comment on the revenue reconciliation. As part of this negotiated Settlement Agreement, all Parties agreed to use EPMC with a 3.2% cap above the overall percentage increase and setting any class that would receive a decrease at 0% change (Present Rate Revenue). Attached is Table A, which summarizes the class impacts under the parties positions and the settlement position. (Sierra's Direct on Marginal Cost of Service, Rate Design, and Master Meter Service, pp 13-7 to 13-11; DRA's Report on Marginal Cost and Rate Design, pp 2-3 to 2-5; TURN's Report on Marginal Cost and Rate Design, pp 16,17; A-3CC Direct and Rebuttal Addressing Revenue Allocation, Rate Design, and Marginal Cost, pp 2 to 6.)

8. Rate Design

8.1 **Residential Rate Design** – Sierra proposed to raise the Residential customer charge from $4.50 to $6.00 with a 15% composite tier differential. DRA accepted Sierra's Residential rate design as filed. TURN recommended increasing the Residential customer charge to $5.40 with a 20% composite tier differential. No other Party commented on this issue. As part of this negotiated Settlement Agreement, TURN agreed to accept Sierra's proposed Residential customer charge of $6.00 and TURN and Sierra agreed to a composite tier differential of 17.5%. (Sierra's Direct on Marginal Cost of Service, Rate Design, and Master Meter Service, pp 13-17 to 13-19; DRA's Report on Marginal Cost and Rate Design, pp 3-1,3-2; TURN's Report on Marginal Cost and Rate Design, pp 18,19.)

8.2 **Master Meter (DS-1) Issues** – Consistent with D.04-11-033, Sierra filed a proposed DS-1 Master Meter discount or credit and provided analysis of the cost, benefits and feasibility of providing bill calculation services to master meter mobile home park owners. Sierra proposed setting the DS-1 Master Meter Credit using a marginal cost approach with the Rental method for calculating customer cost. Sierra's proposal also includes providing a large portion of the credit to its DS-1 customers through the customer charge component, whereby the DS-1 customer pays only one customer charge to Sierra which in turn collects the customer charge from each tenant. Sierra then proposes to provide the balance of the credit to DS-1 customers on a $/tenant/day basis. Furthermore, Sierra proposed to include an additional adjustment, known as the baseline diversity benefit adjustment (DBA), which would offset a portion of the credit and would be stated on $/permanent tenant/day.

WMA did not object to the overall methodology for calculating or implementing the credit. However, WMA proposed to revise Sierra's calculation of the credit to add transformer avoided cost. In its rebuttal, Sierra supported its filed calculation but supplemented the calculation with one including its valuation of transformer avoided costs. As part of this negotiated Settlement Agreement, Sierra and WMA agree to a corrected calculation similar to that included in Sierra's rebuttal. The Parties agree that the structure of the credit and its implementation will be implemented by Sierra as it was proposed in its DS-1 tariff. Sierra and WMA agree to use Sierra's calculation methodology for the baseline diversity benefit adjustment (DBA). The DBA will be stated on a $/permanent tenant/day basis as proposed by Sierra, and will be implemented as in the DS-1 tariff as proposed by Sierra.

Sierra and WMA also agree to include in the submetering credit an adjustment for common area usage using a calculation methodology within the range detailed in Sierra's rebuttal testimony of 5% for purposes of this settlement. The common use adjustment will be stated on a $/tenant/day basis and included in the submetering credit. Sierra agrees that it will provide an estimate of common area usage in its next GRC for this adjustment, but may or may not propose to make this adjustment in that proceeding.

Sierra provided analysis of three billing options and proposed to offer none. WMA recommended that Sierra implement an option similar to that filed by Southern California Edison in A. 04-12-014 and similar to Sierra's Option 3. As part of this negotiated Settlement Agreement, Sierra and WMA agree that Sierra will implement its filed Option 1, internet based bill calculation tool, and agree that the cost identified to provide this service will not be included in the DS-1 rate schedule. Sierra will also update its cost estimates for providing broader bill calculation service options in its next GRC. However, Sierra is not bound to propose offering such services. (Sierra's Direct on Marginal Cost of Service, Rate Design, and Master Meter Service, pp 15-16, 15-17, Appendix A; Sierra's Rebuttal on Marginal Cost of Service, Rate Design, and Master Meter Service, pp 4-6 to 4-9; DRA's Report on Marginal Cost and Rate Design, pp 4-1,4-2; WMA Direct Testimony, pp 5 to 9.)

9. <u>Uncontested Items</u>

All items that appear in Sierra's direct case that are not discussed in this Settlement Agreement were either accepted by Sierra in its Rebuttal Testimony on Results of Operations (pp1-2 to 1-4) or were unopposed by any Party.

IN WITNESS WHEREOF, the parties have executed this Settlement Agreement on January 24, 2006.

SIERRA PACIFIC POWER COMPANY

By: ______________________________

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Table A (page 1 of 2)

STIPULATION: Class Revenue Allocations and Rate Impacts
Settlement Allocation with a 3.2% Upside Cap and 0% Downside Floor

Class Revenue Requirements & Rate Impacts
Revenues Only*

		Present Rate Revenue ($1,000s)		Proposed Rate Revenue ($1,000s)	Percent Change Proposed to Present
Total Residential	$	28,442	$	31,290	10.01%
Residential (DM-1, D-1)	$	28,097	$	30,945	10.14%
Sub-meter Res. (DS-1)	$	345	$	344	-0.23%
A-1	$	10,996	$	11,754	6.89%
A-2	$	5,929	$	5,929	0.00%
A-3	$	10,751	$	11,030	2.59%
Street Lights	$	117	$	129	10.14%
OLS	$	149	$	165	10.14%
PA	$	60	$	66	10.06%
Total	$	56,445	$	60,361	6.94%

* Rate revenues exclude surcharge revenues such as PPP & FTA and ECAC balancing revenues.

Class Revenue Requirements & Rate Impacts
Total Revenues*

		Present Rate Revenue ($1,000s)		Proposed Rate Revenue ($1,000s)	Percent Change Proposed to Present
Total Residential	$	33,334	$	36,273	8.82%
Residential (DM-1, D-1)	$	32,919	$	35,857	8.93%
Sub-meter Res. (DS-1)	$	415	$	416	0.11%
A-1	$	12,669	$	13,459	6.23%
A-2	$	6,457	$	6,477	0.31%
A-3	$	11,835	$	12,153	2.69%
Street Lights	$	121	$	133	9.88%
OLS	$	156	$	172	9.81%
PA	$	66	$	72	9.46%
Total	$	64,638	$	68,739	6.34%

* Includes rate revenues, all surcharge revenues (PPP, FTA and Energy Commission Charges), and ECAC balancing revenues.

Table A (page 2 of 2)

REVENUE ALLOCATION & RATE IMPACTS UNDER INITIAL REVENUE ALLOCATION PROPOSALS OF PARTIES* BASED ON FINAL STIPULATION REVENUE REQUIREMENT & OTHER ELEMENTS OF THE SETTLEMENT

	Sierra's Revenue Allocation 5% Cap and No Downside Limit			A-3CC's Pure Cost-Based Reconciliation No Cap or Floor			DRA's Revenue Allocation 2.5% Cap & No Reduction for any Class		
Rate Classes		Revenue Allocation by Class	% increase over Present Rate Revenue		Revenue Allocation by Class	% increase over Present Rate Revenue		Revenue Allocation by Class	% increase over Present Rate Revenue
			----L----			----L----			----L----
Residential (DM-1, D-1)	$	31,451	11.94%	$	32,097	14.24%	$	30,749	9.44%
Res. Sub-meter. (DS-1)	$	351	1.73%	$	360	4.25%	$	342	-1.00%
A-1	$	11,729	6.67%	$	11,419	3.85%	$	11,750	6.85%
A-2	$	5,445	-8.16%	$	5,301	-10.59%	$	6,089	2.70%
A-3	$	11,020	2.50%	$	10,728	-0.21%	$	11,076	3.02%
Street Lights	$	131	11.94%	$	169	44.95%	$	128	9.44%
OLS	$	167	11.94%	$	221	48.15%	$	164	9.44%
PA	$	66	9.96%	$	64	7.14%	$	64	7.35%
Total	$	60,361	6.94%	$	60,361	6.94%	$	60,361	6.94%

*TURN's revenue allocation proposal can not be meaningfully shown, since it's revenue allocation proposal was tied to its proposed changes to the marginal cost study and unbundling study. TURN's results showed the residential classes' cost-based revenues as being approx. 3.2% above the overall increase sought by Sierra initially. Thus, in this context, TURN accepted Sierra's 5% cap, with no downside floor.

Sierra Pacific Power Company
Summary Results of Operations - California Total
Forecasted Twelve Months Ended December 31, 2006
(000$)

LN #	(A) Description	(B) Stipulated	(C) Sierra	(D) ORA	(E) TURN	(F) Difference (B) - (C)	(G) Difference (B) - (D)	(H) Difference (B) - (E)
1								
2	Revenue Change By Component							
3	Generation	$ 940	$ 883	$ (78)	$ 1,729	$ 57	$ 1,018	$ (789)
4	Transmission	485	859	362	793	(374)	123	(308)
5	Distribution	2,673	6,440	1,555	5,290	(3,767)	1,118	(2,617)
6	Total	$ 4,098	$ 8,182	$ 1,839	$ 7,812	(4,084)	2,259	(3,714)

Sierra Pacific Power Company
Summary Results of Operations - California Total
Forecasted Twelve Months Ended December 31, 2006
(000$)

LN #	(A) Description	(B) Stipulated	(C) Sierra	(D) ORA	(E) TURN	(F) (B) - (C)	(G) (B) - (D)	(H) (B) - (E)
		Forecast Results After Revenue Requirement				Difference		
1	***Operating Revenues***							
2	Sales Revenues (1)	$ 65,465	$ 69,549	$ 63,206	$ 69,179	$ (4,084)	$ 2,259	$ (3,714)
3	Other Operating Revenues	454	430	454	430	24	-	24
4	Revenue Credits	116	116	116	116	-	-	-
5	Total Operating Revenues	66,035	70,095	63,776	69,725	(4,060)	2,259	(3,690)
6								
7	***Operating Expenses***							
8	Steam Power Generation	1,213	1,213	1,213	1,213	-	-	-
9	Hydro Power Generation	-	-	-	-	-	-	-
10	Other Power Generation	275	275	275	275	-	-	-
11	Other Power Supply	3	3	3	3	-	-	-
12	Transmission	236	236	236	236	-	-	-
13	Distribution	1,978	1,978	1,978	1,978	-	-	-
14	Customer Accounts	2,272	2,272	2,272	2,272	-	-	-
15	Uncollectibles	183	194	176	194	(11)	7	(11)
16	Customer Service & Information	961	1,291	630	1,291	(330)	331	(330)
17	Administrative & General	5,430	6,610	4,574	6,399	(1,180)	856	(969)
18	Fuel and Purchase Power	32,765	32,765	32,765	32,765	-	-	-
19	Subtotal	45,316	46,837	44,122	46,626	(1,521)	1,194	(1,310)
20	Deferred Income Taxes	1,994	1,734	2,427	1,693	260	(433)	301
21	Amortization of ITC	(163)	(134)	(133)	(134)	(29)	(30)	(29)
22	Depreciation & Amortization	6,359	7,580	6,313	7,580	(1,221)	46	(1,221)
23	Taxes Other Than Income	2,293	2,338	2,250	2,334	(45)	43	(41)
24	CA Corporate Franchise Tax	134	162	120	163	(28)	14	(29)
25	Federal Income Taxes	904	1,846	(144)	1,852	(942)	1,048	(948)
26	Total Operating Expenses	56,837	60,363	54,955	60,114	(3,526)	1,882	(3,277)
27	Net Operating Income	$ 9,198	$ 9,732	$ 8,821	$ 9,611	$ (534)	$ 377	$ (413)
28								
29	***Rate Base***							
30	Electric Plant In Service							
31	Production	$ 30,988	$ 30,988	$ 30,989	$ 30,988	$ -	$ (1)	$ -
32	Transmission	26,344	26,344	24,949	26,344	-	1,395	-
33	Distribution	136,091	138,114	136,092	138,115	(2,023)	(1)	(2,024)
34	Intangible	1,208	1,207	1,207	1,207	1	1	1
35	General	8,006	8,006	7,477	8,007	-	529	(1)
36	Common	8,519	8,520	7,955	8,519	(1)	564	-
37	Total Plant	211,156	213,179	208,669	213,180	(2,023)	2,487	(2,024)
38	Additions					-	-	-
39	Materials & Supplies	1,727	2,589	1,740	2,590	(862)	(13)	(863)
40	Prepayments	1,906	1,907	1,819	1,907	(1)	87	(1)
41	Other Additions	4,338	5,154	1,463	4,339	(816)	2,875	(1)
42	Working Cash	2,924	2,956	2,936	2,727	(32)	(12)	197
43	Total Additions	10,895	12,606	7,958	11,563	(1,711)	2,937	(668)
44	Deductions					-	-	-
45	Customer Advances	4,489	4,489	4,489	4,489	-	-	-
46	Accum Deferred Inc Taxes	17,467	17,533	17,550	17,552	(66)	(83)	(85)
47	Accum Deferred Invst Tax Cred	1	1	1	1	-	-	-
48	Other Deductions	4,586	4,586	4,350	4,856	-	236	(270)
49	Total Deductions	26,543	26,609	26,390	26,898	(66)	153	(355)
50	Depreciation Reserve	90,153	91,531	89,194	91,532	(1,378)	959	(1,379)
51	Rate Base	$ 105,355	$ 107,645	$ 101,043	$ 106,313	(2,290)	4,312	(958)
52								
53	Rate of Return	8.73%	9.04%	8.73%	9.04%	-0.31%	0.00%	-0.31%
54								

55 (1) Sales revenue does not reflect the Trust Transfer Amount (TTA) revenues currently in rates because these revenues are dedicated to repaying the rate reduction bonds Sierra issued in
56 1999 resulting from the AB1890 10% rate reduction. The forecasted amount of 2006 TTA revenues is $3,273. The TTA rates are adjusted annually and will remain in effect until 2009. The
57 total sales revenues including TTA after revenue requirement is $68,738.

Sierra Pacific Power Company
Summary Results of Operations - California - Generation
Forecasted Twelve Months Ended December 31, 2006
(000$)

LN #	(A) Description	(B) Stipulated	(C) Sierra	(D) ORA	(E) TURN	(F) Difference (B) - (C)	(G) Difference (B) - (D)	(H) Difference (B) - (E)
		Forecast Results After Revenue Requirement						
1	***Operating Revenues***							
2	Sales Revenues	$ 37,781	$ 37,724	$ 36,763	$ 38,570	$ 57	$ 1,018	$ (789)
3	Other Operating Revenues	110	258	273	104	(148)	(163)	6
4	Revenue Credits	17	17	17	17	-	-	-
5	Total Operating Revenues	37,908	37,999	37,053	38,691	(91)	855	(783)
6								
7	***Operating Expenses***							
8	Steam Power Generation	1,213	1,213	1,213	1,213	-	-	-
9	Hydro Power Generation	-	-	-	-	-	-	-
10	Other Power Generation	275	275	275	275	-	-	-
11	Other Power Supply	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-
13	Distribution	-	-	-	-	-	-	-
14	Customer Accounts	-	-	-	-	-	-	-
15	Uncollectibles	105	105	102	108	-	3	(3)
16	Customer Service & Information	-	-	-	450	-	-	(450)
17	Administrative & General	1,272	1,717	1,023	1,740	(445)	249	(468)
18	Fuel and Purchase Power	32,765	32,765	32,765	32,765	-	-	-
19	Subtotal	35,630	36,075	35,378	36,551	(445)	252	(921)
20	Deferred Income Taxes	1,598	1,353	635	1,445	245	963	153
21	Amortization of ITC	(27)	(22)	(22)	(22)	(5)	(5)	(5)
22	Depreciation & Amortization	1,584	1,318	1,584	1,333	266	-	251
23	Taxes Other Than Income	317	316	309	631	1	8	(314)
24	CA Corporate Franchise Tax	41	41	35	47	-	6	(6)
25	Federal Income Taxes	(2,672)	(2,735)	(2,033)	(2,853)	63	(639)	181
26	Total Operating Expenses	36,471	36,346	35,886	37,132	125	585	(661)
27	Net Operating Income	$ 1,437	$ 1,653	$ 1,167	$ 1,559	$ (216)	$ 270	$ (122)
28								
29	***Rate Base***							
30	Electric Plant In Service							
31	Production	$ 30,988	$ 30,988	$ 30,989	$ 30,988	$ -	$ (1)	$ -
32	Transmission	-	-	-	-	-	-	-
33	Distribution	-	-	-	-	-	-	-
34	Intangible	270	258	283	331	12	(13)	(61)
35	General	1,713	1,705	1,707	1,752	8	6	(39)
36	Common	1,823	1,815	1,816	1,864	8	7	(41)
37	Total Plant	34,794	34,766	34,795	34,935	28	(1)	(141)
38	Additions					-	-	-
39	Materials & Supplies	285	1,139	290	1,141	(854)	(5)	(856)
40	Prepayments	378	376	378	384	2	-	(6)
41	Other Additions	2,883	3,698	12	2,886	(815)	2,871	(3)
42	Working Cash	2,577	2,577	2,400	2,311	-	177	266
43	Total Additions	6,123	7,790	3,080	6,722	(1,667)	3,043	(599)
44	Deductions					-	-	-
45	Customer Advances	-	-	-	-	-	-	-
46	Accum Deferred Inc Taxes	3,713	3,684	3,765	3,701	29	(52)	12
47	Accum Deferred Invst Tax Cred	-	-	-	-	-	-	-
48	Other Deductions	884	880	881	901	4	3	(17)
49	Total Deductions	4,597	4,564	4,646	4,602	33	(49)	(5)
50	Depreciation Reserve	19,860	19,712	19,862	19,810	148	(2)	50
51	Rate Base	$ 16,460	$ 18,280	$ 13,367	$ 17,245	(1,820)	3,093	(785)
52								
53	Rate of Return	8.73%	9.04%	8.73%	9.04%	-0.31%	0.00%	-0.31%

Sierra Pacific Power Company
Summary Results of Operations - California - Transmission
Forecasted Twelve Months Ended December 31, 2006
(000$)

LN #	(A) Description	(B) Stipulated	(C) Sierra	(D) ORA	(E) TURN	(F) (B) - (C)	(G) Difference (B) - (D)	(H) (B) - (E)
		Forecast Results After Revenue Requirement						
1	***Operating Revenues***							
2	Sales Revenues	$ 2,929	$ 3,303	$ 2,806	$ 3,237	$ (374)	$ 123	$ (308)
3	Other Operating Revenues	7	17	18	7	(10)	(11)	-
4	Revenue Credits	99	99	99	99	-	-	-
5	Total Operating Revenues	3,035	3,419	2,923	3,343	(384)	112	(308)
6								
7	***Operating Expenses***							
8	Steam Power Generation	-	-	-	-	-	-	-
9	Hydro Power Generation	-	-	-	-	-	-	-
10	Other Power Generation	-	-	-	-	-	-	-
11	Other Power Supply	3	3	3	3	-	-	-
12	Transmission	236	236	236	236	-	-	-
13	Distribution	-	-	-	-	-	-	-
14	Customer Accounts	-	-	-	-	-	-	-
15	Uncollectibles	9	9	8	9	-	1	-
16	Customer Service & Information	-	-	-	-	-	-	-
17	Administrative & General	261	286	229	283	(25)	32	(22)
18	Fuel and Purchase Power	-	-	-	-	-	-	-
19	Subtotal	509	534	476	531	(25)	33	(22)
20	Deferred Income Taxes	51	23	93	20	28	(42)	31
21	Amortization of ITC	(21)	(17)	(16)	(17)	(4)	(5)	(4)
22	Depreciation & Amortization	490	687	529	687	(197)	(39)	(197)
23	Taxes Other Than Income	294	296	283	219	(2)	11	75
24	CA Corporate Franchise Tax	13	16	12	16	(3)	1	(3)
25	Federal Income Taxes	238	371	163	375	(133)	75	(137)
26	Total Operating Expenses	1,574	1,910	1,540	1,831	(336)	34	(257)
27	Net Operating Income	$ 1,461	$ 1,509	$ 1,383	$ 1,512	$ (48)	$ 78	$ (51)
28								
29	***Rate Base***							
30	Electric Plant In Service							
31	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Transmission	26,344	26,344	24,949	26,344	-	1,395	-
33	Distribution	-	-	-	-	-	-	-
34	Intangible	42	40	44	40	2	(2)	2
35	General	343	342	342	342	1	1	1
36	Common	365	364	364	364	1	1	1
37	Total Plant	27,094	27,090	25,699	27,090	4	1,395	4
38	Additions					-	-	-
39	Materials & Supplies	220	220	214	220	-	6	-
40	Prepayments	134	133	130	133	1	4	1
41	Other Additions	135	135	135	135	-	-	-
42	Working Cash	62	64	66	105	(2)	(4)	(43)
43	Total Additions	551	552	545	593	(1)	6	(42)
44	Deductions					-	-	-
45	Customer Advances	-	-	-	-	-	-	-
46	Accum Deferred Inc Taxes	3,099	3,077	2,976	3,080	22	123	19
47	Accum Deferred Invst Tax Cred	-	-	-	-	-	-	-
48	Other Deductions	165	165	165	165	-	-	-
49	Total Deductions	3,264	3,242	3,141	3,245	22	123	19
50	Depreciation Reserve	7,645	7,709	7,262	7,708	(64)	383	(63)
51	Rate Base	$ 16,736	$ 16,691	$ 15,841	$ 16,730	45	895	6
52								
53	Rate of Return	8.73%	9.04%	8.73%	9.04%	-0.31%	0.00%	-0.31%

Sierra Pacific Power Company
Summary Results of Operations - California - Distribution
Forecasted Twelve Months Ended December 31, 2006
(000$)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Forecast Results After Revenue Requirement						
							Difference	
LN #	Description	Stipulated	Sierra	ORA	TURN	(B) - (C)	(B) - (D)	(B) - (E)
1	***Operating Revenues***							
2	Sales Revenues	$ 24,755	$ 28,522	$ 23,637	$ 27,372	$ (3,767)	$ 1,118	$ (2,617)
3	Other Operating Revenues	337	155	163	319	182	174	18
4	Revenue Credits	-	-	-	-	-	-	-
5	Total Operating Revenues	25,092	28,677	23,800	27,691	(3,585)	1,292	(2,599)
6								
7	***Operating Expenses***							
8	Steam Power Generation	-	-	-	-	-	-	-
9	Hydro Power Generation	-	-	-	-	-	-	-
10	Other Power Generation	-	-	-	-	-	-	-
11	Other Power Supply	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-
13	Distribution	1,978	1,978	1,978	1,978	-	-	-
14	Customer Accounts	2,272	2,272	2,272	2,272	-	-	-
15	Uncollectibles	69	80	66	77	(11)	3	(8)
16	Customer Service & Information	961	1,291	630	841	(330)	331	120
17	Administrative & General	3,897	4,607	3,322	4,376	(710)	575	(479)
18	Fuel and Purchase Power	-	-	-	-	-	-	-
19	Subtotal	9,177	10,228	8,268	9,544	(1,051)	909	(367)
20	Deferred Income Taxes	345	358	1,699	228	(13)	(1,354)	117
21	Amortization of ITC	(115)	(95)	(95)	(95)	(20)	(20)	(20)
22	Depreciation & Amortization	4,285	5,575	4,200	5,560	(1,290)	85	(1,275)
23	Taxes Other Than Income	1,682	1,726	1,658	1,484	(44)	24	198
24	CA Corporate Franchise Tax	80	105	73	100	(25)	7	(20)
25	Federal Income Taxes	3,338	4,210	1,726	4,330	(872)	1,612	(992)
26	Total Operating Expenses	18,792	22,107	17,529	21,151	(3,315)	1,263	(2,359)
27	Net Operating Income	$ 6,300	$ 6,570	$ 6,271	$ 6,540	$ (270)	$ 29	$ (240)
28								
29	***Rate Base***							
30	Electric Plant In Service							
31	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Transmission	-	-	-	-	-	-	-
33	Distribution	136,091	138,114	136,092	138,115	(2,023)	(1)	(2,024)
34	Intangible	896	909	880	836	(13)	16	60
35	General	5,950	5,959	5,428	5,913	(9)	522	37
36	Common	6,331	6,341	5,775	6,291	(10)	556	40
37	Total Plant	149,268	151,323	148,175	151,155	(2,055)	1,093	(1,887)
38	Additions					-	-	-
39	Materials & Supplies	1,222	1,230	1,236	1,229	(8)	(14)	(7)
40	Prepayments	1,394	1,398	1,311	1,390	(4)	83	4
41	Other Additions	1,320	1,321	1,316	1,318	(1)	4	2
42	Working Cash	285	315	470	311	(30)	(185)	(26)
43	Total Additions	4,221	4,264	4,333	4,248	(43)	(112)	(27)
44	Deductions					-	-	-
45	Customer Advances	4,489	4,489	4,489	4,489	-	-	-
46	Accum Deferred Inc Taxes	10,655	10,772	10,809	10,771	(117)	(154)	(116)
47	Accum Deferred Invst Tax Cred	1	1	1	1	-	-	-
48	Other Deductions	3,537	3,541	3,304	3,790	(4)	233	(253)
49	Total Deductions	18,682	18,803	18,603	19,051	(121)	79	(369)
50	Depreciation Reserve	62,648	64,110	62,070	64,014	(1,462)	578	(1,366)
51	Rate Base	$ 72,159	$ 72,674	$ 71,835	$ 72,338	(515)	324	(179)
52								
53	Rate of Return	8.73%	9.04%	8.73%	9.04%	-0.31%	0.00%	-0.31%

Sierra Pacific Power Company
Summary Results of Operations - California Total
Forecasted Twelve Months Ended December 31, 2003
(000$)

LN #	(A) Description	(B) Stipulated	(C) Sierra	(D) ORA	(E) TURN	(F) (B) - (C)	(G) (B) - (D)	(H) (B) - (E)
			Forecast Results Before Revenue Requirement			Difference		
1	***Operating Revenues***							
2	Sales Revenues (1)	$ 61,367	$ 61,367	$ 61,367	$ 61,367	$ -	$ -	$ -
3	Other Operating Revenues	454	430	454	430	24	-	24
4	Revenue Credits	116	116	116	116	-	-	-
5	Total Operating Revenues	61,937	61,913	61,937	61,913	24	-	24
6								
7	***Operating Expenses***							
8	Steam Power Generation	1,213	1,213	1,213	1,213	-	-	-
9	Hydro Power Generation	-	-	-	-	-	-	-
10	Other Power Generation	275	275	275	275	-	-	-
11	Other Power Supply	3	3	3	3	-	-	-
12	Transmission	236	236	236	236	-	-	-
13	Distribution	1,978	1,978	1,978	1,978	-	-	-
14	Customer Accounts	2,272	2,272	2,272	2,272	-	-	-
15	Uncollectibles	172	172	172	172	-	-	-
16	Customer Service & Information	961	1,291	630	1,291	(330)	331	(330)
17	Administrative & General	5,431	6,610	4,574	6,399	(1,179)	857	(968)
18	Fuel and Purchase Power	32,765	32,765	32,765	32,765	-	-	-
19	Subtotal	45,306	46,815	44,118	46,604	(1,509)	1,188	(1,298)
20	Deferred Income Taxes	1,994	1,734	2,427	1,693	260	(433)	301
21	Amortization of ITC	(163)	(134)	(133)	(134)	(29)	(30)	(29)
22	Depreciation & Amortization	6,359	7,580	6,313	7,580	(1,221)	46	(1,221)
23	Taxes Other Than Income	2,250	2,253	2,230	2,253	(3)	20	(3)
24	CA Corporate Franchise Tax	108	109	109	112	(1)	(1)	(4)
25	Federal Income Taxes	(508)	(973)	(778)	(840)	465	270	332
26	Total Operating Expenses	55,346	57,384	54,286	57,268	(2,038)	1,060	(1,922)
27	Net Operating Income	$ 6,591	$ 4,529	$ 7,651	$ 4,645	$ 2,062	$ (1,060)	$ 1,946
28								
29	***Rate Base***							
30	Electric Plant In Service							
31	Production	$ 30,988	$ 30,988	$ 30,989	$ 30,988	$ -	$ (1)	$ -
32	Transmission	26,344	26,344	24,949	26,344	-	1,395	-
33	Distribution	136,091	138,114	136,092	138,115	(2,023)	(1)	(2,024)
34	Intangible	1,208	1,207	1,207	1,207	1	1	1
35	General	8,006	8,006	7,477	8,007	-	529	(1)
36	Common	8,519	8,520	7,955	8,519	(1)	564	-
37	Total Plant	211,156	213,179	208,669	213,180	(2,023)	2,487	(2,024)
38	Additions					-	-	-
39	Materials & Supplies	1,727	2,589	1,740	2,590	(862)	(13)	(863)
40	Prepayments	1,906	1,907	1,819	1,907	(1)	87	(1)
41	Other Additions	4,338	5,154	1,463	4,339	(816)	2,875	(1)
42	Working Cash	3,060	3,223	2,998	2,982	(163)	62	78
43	Total Additions	11,031	12,873	8,020	11,818	(1,842)	3,011	(787)
44	Deductions					-	-	-
45	Customer Advances	4,489	4,489	4,489	4,489	-	-	-
46	Accum Deferred Inc Taxes	17,467	17,533	17,550	17,552	(66)	(83)	(85)
47	Accum Deferred Invst Tax Cred	1	1	1	1	-	-	-
48	Other Deductions	4,586	4,586	4,350	4,856	-	236	(270)
49	Total Deductions	26,543	26,609	26,390	26,898	(66)	153	(355)
50	Depreciation Reserve	90,153	91,531	89,194	91,532	(1,378)	959	(1,379)
51	Rate Base	$ 105,491	$ 107,912	$ 101,105	$ 106,568	(2,421)	4,386	(1,077)
52								
53	Rate of Return	6.25%	4.20%	7.57%	4.36%	2.05%	-1.32%	1.89%
54								

55 (1) Sales revenue does not reflect the Trust Transfer Amount (TTA) revenues currently in rates because these revenues are dedicated to repaying the rate reduction bonds Sierra issued in
56 1999 resulting from the AB1890 10% rate reduction. The forecasted amount of 2006 TTA revenues is $3,273. The TTA rates are adjusted annually and will remain in effect until 2009. The
57 total sales revenues including TTA before revenue requirement is $64,640.

Sierra Pacific Power Company
Summary Results of Operations - California - Generation
Forecasted Twelve Months Ended December 31, 2006
(000$)

LN #	(A) Description	(B) Stipulated	(C) Sierra	(D) ORA	(E) TURN	(F) Difference (B) - (C)	(G) Difference (B) - (D)	(H) Difference (B) - (E)
		Forecast Results Before Revenue Requirement						
1	**Operating Revenues**							
2	Sales Revenues	$ 36,841	$ 36,841	$ 36,841	$ 36,841	$ -	$ -	$ -
3	Other Operating Revenues	110	258	273	104	(148)	(163)	6
4	Revenue Credits	17	17	17	17	-	-	-
5	Total Operating Revenues	36,968	37,116	37,131	36,962	(148)	(163)	6
6								
7	**Operating Expenses**							
8	Steam Power Generation	1,213	1,213	1,213	1,213	-	-	-
9	Hydro Power Generation	-	-	-	-	-	-	-
10	Other Power Generation	275	275	275	275	-	-	-
11	Other Power Supply	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-
13	Distribution	-	-	-	-	-	-	-
14	Customer Accounts	-	-	-	-	-	-	-
15	Uncollectibles	103	103	103	103	-	-	-
16	Customer Service & Information	-	-	-	450	-	-	(450)
17	Administrative & General	1,272	1,717	1,023	1,740	(445)	249	(468)
18	Fuel and Purchase Power	32,765	32,765	32,765	32,765	-	-	-
19	Subtotal	35,628	36,073	35,379	36,546	(445)	249	(918)
20	Deferred Income Taxes	1,598	1,353	635	1,445	245	963	153
21	Amortization of ITC	(27)	(22)	(22)	(22)	(5)	(5)	(5)
22	Depreciation & Amortization	1,584	1,318	1,584	1,333	266	-	251
23	Taxes Other Than Income	307	307	309	613	-	(2)	(306)
24	CA Corporate Franchise Tax	35	35	36	36	-	(1)	(1)
25	Federal Income Taxes	(2,996)	(3,039)	(2,007)	(3,449)	43	(989)	453
26	Total Operating Expenses	36,129	36,025	35,914	36,502	104	215	(373)
27	Net Operating Income	$ 839	$ 1,091	$ 1,217	$ 460	$ (252)	$ (378)	$ 379
28								
29	**Rate Base**							
30	Electric Plant In Service							
31	Production	$ 30,988	$ 30,988	$ 30,989	$ 30,988	$ -	$ (1)	$ -
32	Transmission	-	-	-	-	-	-	-
33	Distribution	-	-	-	-	-	-	-
34	Intangible	270	258	283	331	12	(13)	(61)
35	General	1,713	1,705	1,707	1,752	8	6	(39)
36	Common	1,823	1,815	1,816	1,864	8	7	(41)
37	Total Plant	34,794	34,766	34,795	34,935	28	(1)	(141)
38	Additions					-	-	-
39	Materials & Supplies	285	1,139	290	1,141	(854)	(5)	(856)
40	Prepayments	378	376	378	384	2	-	(6)
41	Other Additions	2,883	3,698	12	2,886	(815)	2,871	(3)
42	Working Cash	2,608	2,606	2,398	2,367	2	210	241
43	Total Additions	6,154	7,819	3,078	6,778	(1,665)	3,076	(624)
44	Deductions					-	-	-
45	Customer Advances	-	-	-	-	-	-	-
46	Accum Deferred Inc Taxes	3,713	3,684	3,765	3,701	29	(52)	12
47	Accum Deferred Invst Tax Cred	-	-	-	-	-	-	-
48	Other Deductions	884	880	881	901	4	3	(17)
49	Total Deductions	4,597	4,564	4,646	4,602	33	(49)	(5)
50	Depreciation Reserve	19,860	19,712	19,862	19,810	148	(2)	50
51	Rate Base	$ 16,491	$ 18,309	$ 13,365	$ 17,301	(1,818)	3,126	(810)
52								
53	Rate of Return	5.09%	5.96%	9.11%	2.66%	-0.87%	-4.02%	2.43%

Sierra Pacific Power Company
Summary Results of Operations - California - Transmission
Forecasted Twelve Months Ended December 31, 2006
(000$)

LN #	(A) Description	(B) Stipulated	(C) Sierra	(D) ORA	(E) TURN	(F) (B) - (C)	(G) Difference (B) - (D)	(H) (B) - (E)
		Forecast Results Before Revenue Requirement						
1	***Operating Revenues***							
2	Sales Revenues	$ 2,444	$ 2,444	$ 2,444	$ 2,444	$ -	$ -	$ -
3	Other Operating Revenues	7	17	18	7	(10)	(11)	-
4	Revenue Credits	99	99	99	99	-	-	-
5	Total Operating Revenues	2,550	2,560	2,561	2,550	(10)	(11)	-
6								
7	***Operating Expenses***							
8	Steam Power Generation	-	-	-	-	-	-	-
9	Hydro Power Generation	-	-	-	-	-	-	-
10	Other Power Generation	-	-	-	-	-	-	-
11	Other Power Supply	3	3	3	3	-	-	-
12	Transmission	236	236	236	236	-	-	-
13	Distribution	-	-	-	-	-	-	-
14	Customer Accounts	-	-	-	-	-	-	-
15	Uncollectibles	7	7	7	7	-	-	-
16	Customer Service & Information	-	-	-	-	-	-	-
17	Administrative & General	261	286	229	283	(25)	32	(22)
18	Fuel and Purchase Power	-	-	-	-	-	-	-
19	Subtotal	507	532	475	529	(25)	32	(22)
20	Deferred Income Taxes	51	23	93	20	28	(42)	31
21	Amortization of ITC	(21)	(17)	(16)	(17)	(4)	(5)	(4)
22	Depreciation & Amortization	490	687	529	687	(197)	(39)	(197)
23	Taxes Other Than Income	289	287	279	211	2	10	78
24	CA Corporate Franchise Tax	10	10	10	10	-	-	-
25	Federal Income Taxes	71	75	39	102	(4)	32	(31)
26	Total Operating Expenses	1,397	1,597	1,409	1,542	(200)	(12)	(145)
27	Net Operating Income	$ 1,153	$ 963	$ 1,152	$ 1,008	$ 190	$ 1	$ 145
28								
29	***Rate Base***							
30	Electric Plant In Service							
31	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Transmission	26,344	26,344	24,949	26,344	-	1,395	-
33	Distribution	-	-	-	-	-	-	-
34	Intangible	42	40	44	40	2	(2)	2
35	General	343	342	342	342	1	1	1
36	Common	365	364	364	364	1	1	1
37	Total Plant	27,094	27,090	25,699	27,090	4	1,395	4
38	Additions					-	-	-
39	Materials & Supplies	220	220	214	220	-	6	-
40	Prepayments	134	133	130	133	1	4	1
41	Other Additions	135	135	135	135	-	-	-
42	Working Cash	78	92	78	131	(14)	-	(53)
43	Total Additions	567	580	557	619	(13)	10	(52)
44	Deductions					-	-	-
45	Customer Advances	-	-	-	-	-	-	-
46	Accum Deferred Inc Taxes	3,099	3,077	2,976	3,080	22	123	19
47	Accum Deferred Invst Tax Cred	-	-	-	-	-	-	-
48	Other Deductions	165	165	165	165	-	-	-
49	Total Deductions	3,264	3,242	3,141	3,245	22	123	19
50	Depreciation Reserve	7,645	7,709	7,262	7,708	(64)	383	(63)
51	Rate Base	$ 16,752	$ 16,719	$ 15,853	$ 16,756	33	899	(4)
52								
53	Rate of Return	6.88%	5.76%	7.27%	6.02%	1.12%	-0.38%	0.87%

Sierra Pacific Power Company
Summary Results of Operations - California - Distribution
Forecasted Twelve Months Ended December 31, 2006
(000$)

LN #	(A) Description	(B) Stipulated	(C) Sierra	(D) ORA	(E) TURN	(F) (B) - (C)	(G) Difference (B) - (D)	(H) (B) - (E)
		Forecast Results Before Revenue Requirement						
1	***Operating Revenues***							
2	Sales Revenues	$ 22,082	$ 22,082	$ 22,082	$ 22,082	$ -	$ -	$ -
3	Other Operating Revenues	337	155	163	319	182	174	18
4	Revenue Credits	-	-	-	-	-	-	-
5	Total Operating Revenues	22,419	22,237	22,245	22,401	182	174	18
6								
7	***Operating Expenses***							
8	Steam Power Generation	-	-	-	-	-	-	-
9	Hydro Power Generation	-	-	-	-	-	-	-
10	Other Power Generation	-	-	-	-	-	-	-
11	Other Power Supply	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-
13	Distribution	1,978	1,978	1,978	1,978	-	-	-
14	Customer Accounts	2,272	2,272	2,272	2,272	-	-	-
15	Uncollectibles	62	62	62	62	-	-	-
16	Customer Service & Information	961	1,291	630	841	(330)	331	120
17	Administrative & General	3,898	4,607	3,322	4,376	(709)	576	(478)
18	Fuel and Purchase Power	-	-	-	-	-	-	-
19	Subtotal	9,171	10,210	8,264	9,529	(1,039)	907	(358)
20	Deferred Income Taxes	345	358	1,699	228	(13)	(1,354)	117
21	Amortization of ITC	(115)	(95)	(95)	(95)	(20)	(20)	(20)
22	Depreciation & Amortization	4,285	5,575	4,200	5,560	(1,290)	85	(1,275)
23	Taxes Other Than Income	1,654	1,659	1,642	1,429	(5)	12	225
24	CA Corporate Franchise Tax	63	64	63	66	(1)	-	(3)
25	Federal Income Taxes	2,417	1,991	1,190	2,507	426	1,227	(90)
26	Total Operating Expenses	17,820	19,762	16,963	19,224	(1,942)	857	(1,404)
27	Net Operating Income	$ 4,599	$ 2,475	$ 5,282	$ 3,177	$ 2,124	$ (683)	$ 1,422
28								
29	***Rate Base***							
30	Electric Plant In Service							
31	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Transmission	-	-	-	-	-	-	-
33	Distribution	136,091	138,114	136,092	138,115	(2,023)	(1)	(2,024)
34	Intangible	896	909	880	836	(13)	16	60
35	General	5,950	5,959	5,428	5,913	(9)	522	37
36	Common	6,331	6,341	5,775	6,291	(10)	556	40
37	Total Plant	149,268	151,323	148,175	151,155	(2,055)	1,093	(1,887)
38	Additions					-	-	-
39	Materials & Supplies	1,222	1,230	1,236	1,229	(8)	(14)	(7)
40	Prepayments	1,394	1,398	1,311	1,390	(4)	83	4
41	Other Additions	1,320	1,321	1,316	1,318	(1)	4	2
42	Working Cash	374	525	522	484	(151)	(148)	(110)
43	Total Additions	4,310	4,474	4,385	4,421	(164)	(75)	(111)
44	Deductions					-	-	-
45	Customer Advances	4,489	4,489	4,489	4,489	-	-	-
46	Accum Deferred Inc Taxes	10,655	10,772	10,809	10,771	(117)	(154)	(116)
47	Accum Deferred Invst Tax Cred	1	1	1	1	-	-	-
48	Other Deductions	3,537	3,541	3,304	3,790	(4)	233	(253)
49	Total Deductions	18,682	18,803	18,603	19,051	(121)	79	(369)
50	Depreciation Reserve	62,648	64,110	62,070	64,014	(1,462)	578	(1,366)
51	Rate Base	$ 72,248	$ 72,884	$ 71,887	$ 72,511	(636)	361	(263)
52								
53	Rate of Return	6.37%	3.40%	7.35%	4.38%	2.97%	-0.98%	1.98%

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document in A.05-06-018:

JOINT MOTION TO ACCEPT SETTLEMENT AGREEMENT; SETTLEMENT AGREEMENT ATTACHED

A copy has been e-mailed on all known parties of record who have provided e-mail addresses. In addition, all parties have been served by first-class mail.

Executed in Reno, Nevada, on the 6th day of February, 2006.

Connie Silveira

Connie Silveira

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

Proceeding: A0506018 - SIERRA PACIFIC POWER
Filer: SIERRA PACIFIC POWER COMPANY (U 903-E)
List Name: LIST
Last changed: September 29, 2005

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(END OF ATTACHMENT A)