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BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

Arizona Corporation Commission
DOCKETED
FEB 23 2005
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IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A RATE INCREASE	DOCKET NO.E-01773A-04-0528
IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE.	DOCKET NO. E-04100A-04-0527 **NOTICE OF FILING DIRECT TESTIMONY**

In regard to Arizona Electric Power Cooperative, Inc., the Utilities Division ("Staff") of the Arizona Corporation Commission hereby files the Direct Testimony of Crystal Brown, Alejandro Ramirez, Barbara Keene, and Jerry Smith.

In regard to Southwest Transmission Cooperative, Inc., the Utilities Division ("Staff") of the Arizona Corporation Commission hereby files the Direct Testimony of Crystal Brown, Alejandro Ramirez, Erin Casper, and Jerry Smith.

RESPECTFULLY SUBMITTED this 23rd day of February 2005.

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DIRECT

TESTIMONY

OF

CRYSTAL S. BROWN

ALEJANDRO RAMIREZ

BARBARA KEENE

JERRY D. SMITH

DOCKET NO. E-01773A-04-0528

IN THE MATTER OF THE APPLICATION OF
ARIZONA ELECTRIC POWER COOPERATIVE,
INC. FOR A RATE INCREASE

FEBRUARY 23, 2005

BROWN

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-04-0528

DIRECT TESTIMONY OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0528

Arizona Electric Power Cooperative, Inc.

Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Cooperative") is a certificated electric generation cooperative that supplied power to six Class A, two Class B, and one Class C member during 2003. The rates requested in this case pertain only to the Class A members.

On July 23, 2004, AEPCO filed an application for a permanent rate increase. The Cooperative states that it incurred an adjusted test year operating loss of $4.5 million resulting in a times interest earned ratio ("TIER") lower than that required by its mortgage covenant agreements.

AEPCO proposed an $8,450,016, or 9.86 percent, revenue increase from $137,611,450 to $146,061,466. The proposed revenue increase would produce an operating margin of $16,422,692 for a 7.39 percent rate of return on an original cost rate base of $222,147,011. The $8,450,016 proposed revenue increase includes $1,887,958 of margin revenue and $6,562,058[1] of base cost of power revenue. Only the $1,887,958 margin increase is comparable to Staff's recommended revenue increase. AEPCO requests a 1.29 TIER.

Staff recommends a revenue requirement no less than the $146,061,466 proposed by AEPCO. This proposed revenue provides a $6,773,320, or 4.86 percent, revenue increase over Staff adjusted Test Year revenues of $139,288,146. Operating revenue of $146,061,466 would produce an operating margin of $17,755,094 for a 9.36 percent rate of return on a Staff adjusted original cost rate base of $189,637,810 and produce a 1.33 TIER.

[1] As shown on Schedule CSB-16, line 4.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Business Administration from the University of Arizona and a Bachelor of Science Degree in Accounting from Arizona State University.

Since joining the Commission, I have participated in numerous rate cases and other regulatory proceedings involving large electric, gas, telecommunications, and water utilities. I have testified on matters involving regulatory accounting and auditing. During the past six years, I have attended utility-related seminars on regulation, accounting, finance and income taxes designed to provide continuing and updated education in these areas. Various professional and industry organizations sponsored these seminars.

I have been employed by the Commission as a regulatory auditor and a rate analyst since August 1996. Prior to joining the Commission, I was employed by the Department of Revenue as a Senior Internal Auditor and by the Office of the Auditor General as a Financial Auditor. I was a Cost Center Review Specialist for Blue Cross Blue Shield of Arizona prior to my employment in state government.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating income, and revenue requirement regarding Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Cooperative") application for a permanent rate increase. Staff witness Alejandro Ramirez is presenting Staff's times interest earned ratio ("TIER") and debt service coverage ("DSC") ratio analysis and recommendations. Staff witness Barbara Keene is presenting Staff's recommendations regarding the base cost of power, fuel adjustor, and rate design. Staff witness Jerry Smith is presenting Staff's engineering analysis and recommendations.

Q. What is the basis of your recommendations?

A. I performed a regulatory audit of AEPCO's application to determine whether sufficient, relevant, and reliable evidence exists to support the Company's requested rate increase. The regulatory audit consisted of examining and testing the financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission adopted National Rural Utilities Service ("RUS") Uniform System of Accounts ("USOA").

BACKGROUND

Q. Please review the background of this application.

A. Prior to August 2001, AEPCO provided both generation and transmission services to its customers. Pursuant to Decision No. 59943, dated December 26, 1996, the Commission approved a phased-in transition to electric competition. In 2001, AEPCO received Commission approval to restructure into three separate affiliated cooperatives: AEPCO, Southwest Transmission Cooperative ("Southwest Transmission"), and Sierra Southwest Cooperative ("Sierra Southwest").

AEPCO became a generation cooperative. Southwest Transmission became a transmission cooperative. Sierra Southwest became a cooperative that provides wholesale marketing and support services, including staffing of non-core positions to AEPCO and Southwest Transmission.

Decision No. 63868 required that the Cooperatives provide the Director of the Utilities Division with "an informational submission" that was required within "35 months of the date of closing"[2] for the restructuring. Decision No. 65367, dated November 5, 2002, modified this requirement to include full Arizona Administrative Code R14-2-103 information and set the rate filing date at July 1, 2004. On July 23, 2004, AEPCO filed an application for a permanent rate increase. On August 27, 2004, Staff filed a Letter of Sufficiency.

AEPCO is a certificated Arizona-based generation cooperative that provided service to six Class A, two Class B, and one Class C member during the test year. The rates requested in this case pertain only to the Class A members.

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[2] Decision No. 63868, Page 14, Finding of Fact No. 74

AEPCO's current rates for Class A members were authorized in Decision No. 58405, dated September 3, 1993 and Decision No. 62758, dated July 27, 2000. Decision No. 58405 authorized a TIER of 1.05 and a DSC of 1.0 to provide a 12.96 percent rate of return on a $259,066,000 rate base. Decision No. 62758 authorized the Cooperative's Competitive Transition charge[3].

Q. What are the primary reasons for the Cooperative's requested permanent rate increase?

A. The Cooperative's application discusses three primary reasons for the rate increase: higher coal and gas costs, increased overhaul and maintenance costs, and costs related to plant placed into service after the Test Year. Additionally, it states that it has incurred a Test Year operating loss of $4.5 million resulting in a TIER lower than that required by its mortgage covenant agreements.

CONSUMER SERVICE

Q. Please provide a brief history of customer complaints received by the Commission regarding AEPCO.

A. Staff reviewed the Commission's records and found no formal complaints from its members from 2001 to 2004. Five opinions opposing the rate increase have been received from retail customers of the distribution member cooperative in Mohave County as of February 7, 2005.

[3] In Decision No. 62758, dated July 27, 2000, the Commission approved the transfer of the regulatory asset charge from AEPCO to Southwest Transmission.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Company's filing.

A. The Cooperative proposes total annual operating revenue for Class A members of $94,135,640. This represents an increase of $8,450,016, or 9.86 percent, over Test Year Class A revenue of $85,685,624.

Q. Please summarize Staff's recommended revenue.

A. Staff recommends a revenue requirement no less than the $146,061,466 proposed by AEPCO. This proposed revenue provides a $6,773,320, or 4.86 percent, revenue increase over Staff adjusted Test Year revenues of $139,288,146. Operating revenue of $146,061,466 would produce an operating margin of $17,755,094 for a 9.36 percent rate of return on a Staff adjusted original cost rate base of $189,637,810 and produce a 1.33 TIER.

Q. What Test Year did AEPCO use in this filing?

A. AEPCO's rate filing is based on the twelve months ended December 31, 2003 ("Test Year").

Q. Please summarize the rate base and operating income recommendations and adjustments addressed in your testimony for AEPCO.

A. My testimony addresses the following issues:

<u>Post-Test Year Plant</u>– This adjustment decreases Plant In Service by $9,952,618 to remove plant that was not used and useful during the Test Year.

Plant Acquisition – This adjustment decreases Plant In Service by $13,238 to properly reflect the original cost rate base and to be consistent with Decision No. 65367.

Accumulated Depreciation – This adjustment decreases Accumulated Depreciation by $253,883 to remove retirement work in progress and accumulated depreciation directly related to the Post-Test Year plant.

Member Advances – This adjustment decreases rate base by $11,982,081. This adjustment recognizes that the interest paid to the Members is recovered through operating expense, and consequently, the advances which are directly related to the interest expense should be removed from rate base to prevent double recovery.

Working Capital – This adjustment to reflect Staff's different calculation of certain Working Capital components and to eliminate the Cooperative's selective recognition of components decreases working capital by $6,897,144.

Deferred Debit – This adjustment to remove items that are not generally included in rate base decreases it by $1,955,373.

Asset Retirement Obligation ("ARO") – This adjustment to remove amounts recorded for financial accounting purposes related to future retirement obligations decreases plant in service by $1,962,630.

Post-Test Year Revenue and Expense – This adjustment to remove expenses is directly related to the Post-Test Year ("PTY") plant and increases operating margin by $143,951.

Revenue and Expense Annualizations – This adjustment to reflect the revenues and expenses at the Test-Year end customer level increases operating margin by $1,007,531.

Asset Retirement Obligation – This adjustment to remove costs recorded for financial accounting purposes related to future retirement obligations increases operating margin and net margins by $69,446 and 642,044, respectively.

Base Cost of Power – This adjustment increases operating margin by $250,000 to reflect annualization of savings from a new power contract. Staff also made an adjustment to segregate the revenue associated with the power costs included in the energy charge for Class A members from other revenues. The latter adjustment has no affect on operating margin.

Overhaul Accrual Expense – This adjustment increases operating margin by $657,788 to reflect a normalized level of expense using historical costs.

Transportation Expense Annualization – This adjustment increases operating margin by $19,560 to reflect the Staff recommended Point to Point rate recommended for Southwest Transmission Cooperative.

Normalized Legal Expense – This adjustment decreases operating margin by $539,989 to reflect legal expenses at a normalized level.

Fuel Expense – This adjustment increases operating margin by $1,053,073 to remove legal costs and interest on long-term debt from fuel expense.

<u>Advertising Expense</u> – This adjustment to remove expenses that are not needed for safe and reliable service increases operating margin by $46,241.

<u>Contributions and Other Expense</u> – This adjustment to remove expenses that are not needed for safe and reliable service increases operating margin by $159,891.

<u>ACC Assessment</u> – This adjustment to remove revenues and expenses that should be treated as pass-through items increases operating margin by $141,606.

<u>Interest Expense on Long-term Debt</u> – This non-operating adjustment to reflect Staff's calculation of interest expense on long-term debt increases net margin by $234,585.

RATE BASE

Fair Value Rate Base

Q. Did the Company prepare a Schedule showing the elements of Reconstruction Cost New Rate Base ("RCND")?

A. No, the Company did not. Therefore, Staff evaluated the original cost rate base as the fair value rate base ("FVRB").

Rate Base Summary

Q. Please summarize Staff's adjustments to AEPCO's rate base shown on Schedules CSB-2 and CSB-3.

A. Staff's adjustments to AEPCO's rate base resulted in a net decrease of $32,509,201, from $222,147,011 to $189,637,810. This decrease was primarily due to (1) Staff removing plant that was not completed and serving customers during the Test Year; (2) recognizing Member Advances as a reduction; and (3) reducing the working capital allowance.

Rate Base Adjustment 1 – Utility Plant In Service, Post-Test Year Plant

Q. What is AEPCO proposing for Utility Plant In Service and Post-Test Year Plant?

A. AEPCO is proposing $389,603,749 for Utility Plant In Service. The amount is composed of $379,651,131 in actual plant that was used and useful during the Test Year and $9,952,618 in Post-Test Year ("PTY") plant as shown on Schedule CSB-4.

Q. Please describe the Post-Test Year Plant.

A. The $9,952,618 in PTY plant is a coal blending facility that was under construction at the end of the Test Year.

Q. What is Staff's recommended treatment for the Post-Test Year Plant?

A. Staff recommends excluding the PTY plant and related operating expenses (i.e., depreciation expense, administration and general, and property taxes) from rates.

Q. What is the effect of AEPCO's proposal to include Post-Test Year plant in rate base?

A. AEPCO's proposal to include the $9.9 million of PTY plant in rate base over-states the revenue requirement, and ultimately, the rates paid by the Class A Member cooperatives' 120,000 customers. The over-stated revenue requirement occurs because the PTY plant creates a mismatch between the revenues, expenses incurred and the plant used to provide service in the Test Year and amounts requested for recovery in rates.

In the absence of extraordinary circumstances, the costs of the historical test year should be used in the development of the revenue requirement. These costs are consistent with the matching principal and result in plant in service measured at the same date as other rate base components and with revenues and expenses of the same accounting period.

Q. When is recognition of PTY plant in rate base appropriate?

A. By definition PTY plant is mismatched with the revenues, expenses and rate base components of the test year. Matching is one of the most fundamental principles of accounting and rate-making. The absence of matching distorts the meaning of and reduces the usefulness of operating income and rate of return for measuring the fairness and reasonableness of rates. Accordingly, recognizing PTY plant in rate base should be granted only in special and unusual cases where failure to do so would create an inequity.

Staff recognizes two such cases:

1. When the magnitude of the investment relative to the utility's total investment is such that not including the PTY plant in the cost of service would jeopardize the utility's financial health; and

2. When all of the following conditions exist:

a. the cost of the PTY plant is significant and substantial,

b. the net impact on revenue and expenses for the PTY plant is known and insignificant,

c. the PTY plant is prudent and necessary for the provision of service and reflects appropriate, efficient, effective, and timely decision-making,

d. the funding source(s) and amounts for the PTY plant are known and recognized in the rate application,

e. the PTY plant is in service at the time of the rate filing,

f. the PTY plant is recorded in a completed plant account(s) in the general ledger and auditable records are available at the time of the rate filing, and

g. all related retirements are recorded in the general ledger and recognized in the rate filing.

Q. Would excluding the PTY plant jeopardize the Cooperative's financial health?

A. No. Staff's revenue requirement is primarily based on the Cooperative's cash flow requirements.

Q. Does the PTY plant meet all of the conditions of the second case necessary for inclusion in rate base?

A. No. The impact on revenues and expenses for the PTY plant cannot be measured with sufficient accuracy to determine that it is insignificant.

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $9,952,618 to remove all PTY plant from rate base as shown on Schedules CSB-3 and CSB-4.

Rate Base Adjustment 2 – Plant Acquisition Adjustment

Q. What is AEPCO proposing for its Plant Acquisition Adjustment?

A. AEPCO is proposing $13,238 for the Plant Acquisition Adjustment as shown on Schedule CSB-5.

Q. The $13,238 Plant Acquisition Adjustment is not material to Rate Base. Why is Staff proposing that it be removed from Rate Base for rate making purposes?

A. In Decision No. 65367, dated November 5, 2002, Staff recommended and the Commission agreed that Southwest Transmission's acquisition adjustment be removed from rate base

(Page 4 at line 23). Southwest's acquisition adjustment is directly related to AEPCO's acquisition adjustment.[4]

Q. Did Staff audit the plant acquisition adjustment in this rate proceeding?

A. Yes, Staff audited the plant acquisition adjustment and found that the Cooperative did not have sufficient documentation to support the adjustment.

Q. Should the plant acquisition adjustment be included in rate base?

A. No, it should not. Original cost rate base is calculated using the original cost of plant assets. An acquisition adjustment, by definition, is not the original cost of an asset because it is the difference between the original cost of an asset and the purchase price. Staff found no sufficient evidence to support the adjustment. Therefore, non-recognition of the acquisition adjustment in rate base is the normal rate-making treatment.

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $13,238 as shown on Schedule CSB-3 and CSB-5.

Rate Base Adjustment 3 –Accumulated Depreciation

Q. What is AEPCO proposing for Accumulated Depreciation?

A. AEPCO is proposing $185,972,877 for Accumulated Depreciation. The amount is composed of $185,718,994 in accumulated depreciation on plant in service, $54,648 in a reduction of accumulated depreciation for a retirement work in progress, and $308,531 in accumulated depreciation for the PTY plant as shown on Schedule CSB-6.

[4] Per response to data request CSB 3-4.

Q. Is retirement work in progress normally a component of rate base?

A. No. Retirement work in progress should reflect a coordinated treatment of the plant to be retired, accumulated depreciation, salvage value and disposal cost. The recordkeeping for the retirement should be completed before rate base is adjusted. A similar adjustment to remove retirement work in progress was made for Southwest Transmission in Decision No. 65367[5], dated November 5, 2002.

In Decision No. 65367[6], dated November 5, 2002, Staff recommended that a retirement work in progress be removed because the amount was questionable and unaudited.[7] The Commission adopted Staff's recommendation. In the instant case, Staff audited the retirement work in progress and determined that it should be removed.

Q. Did Staff remove the $308,531 of Accumulated Depreciation directly related to the Post-Test Year plant?

A. Yes. Consistent with Staff's recommendation to remove PTY Plant, Staff recommends removing the Accumulated Depreciation directly related to the PTY plant.

Q. What is Staff recommending?

A. Staff recommends decreasing Accumulated Depreciation by $253,883, from $185,972,877 to $185,718,994 as shown on Schedules CSB-3 and CSB-6.

[5] Page 24 at line 23
[6] Page 24 at line 23
[7] Decision No. 65367, page 4, lines 6 through 9

Rate Base Adjustment 4 – Member Advances

Q. What programs does AEPCO have that result in Member Advances

A. The two types of programs are member investments and member prepaid power bills. The member investment program allows members to invest funds with the Cooperative and the Cooperative pays interest on those funds. The prepaid power program allows members to make prepayments on their monthly power bills and the Cooperative pays interest on those prepaid bills.

Q. How does the Cooperative treat the balance of Member Advances and the interest paid on those funds in its filing?

A. The Cooperative did not deduct the $11,982,081[8] million in Member Advances in its rate base calculation, but it included the $166,385[9] of interest paid to members for use of their funds as an operating expense. An inequity is created by the Cooperative's proposal because its provides for recovery of AEPCO's Member Advances costs by treating the related interest as an operating expense without also recognizing that AEPCO has use of the funds advanced by members.

Q. What is the effect of the Cooperative's proposed treatment?

A. The effect of the Cooperative's proposed treatment is to provide double recovery. The Cooperative pays interest to the members that provide the advances and recovers that interest cost by including it in operating expenses. Failure to deduct Member Advances overstates rate base by not recognizing the Cooperative's use of the advanced funds and has the effect, theoretically, of providing a return on the advanced funds.

[8] Per data request response CSB 1-21
[9] Per data request response CSB 3-19

Q. Did the Commission deduct Member Advances in the rate base calculation of the Cooperative's prior rate case?

A. Yes. The Commission, in Decision No. 58405, deducted Member Advances in the rate base calculation.

Q. What is Staff recommending?

A. Consistent with Decision No. 58405, Staff recommends that $11,982,081 in Member Advances be deducted from rate base as shown on Schedules CSB-3 and CSB-7.

Rate Base Adjustment 5 – Working Capital

Q. What is AEPCO proposing for Working Capital?

A. AEPCO is proposing $16,778,408 for Working Capital. The amount is composed of $5,581,933 for fuel stock, $5,265,561 for materials and supplies, $908,046 for prepayments, and $5,022,869 for CFC Certificates and Bonds as shown on Schedule CSB-8.

Q. Did Staff make any adjustments to the Cooperative's Working Capital?

A. Yes. Staff discusses its adjustments to fuel stock, materials and supplies, prepayments, CFC Certificates and Bonds separately.

Working Capital - Fuel Stock, Coal

Q. Why, in general, is it necessary for generation cooperatives to maintain fuel inventories?

A. Fuel inventories are necessary to help ensure the availability of power to customers on a continuous basis. Coal deliveries can be interrupted for many reasons and are not conducive to deliveries made within short time frames.

Q. What amount in fuel stock is AEPCO proposing?

A. AEPCO is proposing $5,581,933 for fuel stock which consists primarily of coal.

Q. How did AEPCO calculate its fuel stock inventory levels during the Test Year?

A. AEPCO's methodology was based on the number of average burn days.[10] Burn days represent the number of days a generating unit could continue to meet customer demands by burning coal already on hand assuming no additional deliveries of coal and an average consumption rate.

Q. AEPCO changed the Number of Burn Days calculation in April[11] of the Test Year which resulted in lower levels of coal inventory. Did AEPCO reflect this lower level of coal inventory in rate base?

A. No, the Cooperative changed its inventory level from 5,300 tons to 4,100[12] tons in April of the Test Year and did not reflect the lower level in rate base.

Q. AEPCO's proposed inventory level is based upon a 13-Month average of fuel stock. Does this calculation over-state the inventory balance included in rate base?

A. Yes it does. This methodology overstates the balance because it includes four months of inventory levels that were calculated using the higher number of burn days.

Q. What methodology to calculate the fuel stock balance does Staff recommend using?

A. Staff recommends basing the inventory balance on the number of burn days rather than on 13-Month average. Staff's recommended inventory balance is calculated by multiplying the number of burn days by the average daily tons per burn day and the average cost per

[10] Per data request response CSB 3-15
[11] Per data request response CSB 1-4, April 2003 AEPCO Monthly Financial Board Report, page 7.1
[12] Per data request response CSB 3-15

ton to obtain the average cost of coal inventory. The calculation is as follows: 42.5[13] burn days x 4,100 tons per burn day x $27.7/ton[14] or $4,826,725.

Q. Did Staff remove fuel related legal expenses from the fuel stock balance?

A. Yes, Staff removed $191,545[15] in fuel related legal costs as shown on Schedule CSB-8.1. Staff discusses this issue in greater detail in Operating Income Adjustment No. 8, Fuel Expense.

Q. What is Staff recommending for the fuel stock balance?

A. Staff recommends $4,635,180 for fuel stock as shown on Schedules CSB-8 and CSB-8.1.

Working Capital - Materials and Supplies

Q. What amount in Materials and Supplies is AEPCO proposing in the Working Capital calculation?

A. AEPCO is proposing $5,265,561 for Materials and Supplies inventory.

Q. How did AEPCO calculate the Materials and Supplies balance proposed in rate base?

A. AEPCO calculated the Materials and Supplies balance using a 13-month average. This method adds together the December 31, 2002, ending Materials and Supplies balance with the Test Year month-end balances and divides by 13.

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[13] Per response to data request CSB 3-15, 42.5 days is the average of the 40 to 45 burn days range
[14] Per response to data request CSB 6-9
[15] Per response to data request CSB 15-3

Q. **Does use of the 13-month average calculation proposed by AEPCO measure the average monthly balance for each month of the Test Year?**

A. No. Therefore, the Cooperative's proposed method could over- or under- state the materials and supplies balance.

Q. **What method provides a more accurate measurement of the average balance each month?**

A. Staff recommends using a 12-month average based on the average inventory balance for each month of the Test Year. To illustrate, the average monthly balance for January is calculated by adding the beginning balance on January 1st (i.e., the ending balance on December 31st of prior year) to the ending balance on January 31st, and dividing the total by two. The 12 monthly averages are totaled and divided by 12 to obtain an average balance.

Q. **What does Staff recommend for the Materials and Supplies balance in the Working Capital calculation?**

A. Staff recommends $5,246,085 for Materials and Supplies as shown on Schedule CSB-8.2.

Working Capital - Prepayments, CFC Certificates and Bonds

Q. **Is AEPCO proposing to include Prepayments, CFC Certificates and Bonds in the Working Capital calculation?**

A. Yes. AEPCO is proposing $908,046 for prepayments, and $5,581,933[16] in CFC Certificates and Bonds.

[16] In response to data request CSB 3-3, the Cooperative indicated that the $5,581,933 balance was the 2002 ending balance rather than the 2003 ending balance. The 2003 ending balance is composed of $2,774,582 of Equity Term Certificates, $1,276,250 of Subscription Term Certificates and $795,000 of Subscription Term Certificates purchased for the Series 1994A Solid Waste Disposal Revenue Bonds.

Q. Does AEPCO's proposal to include Prepayments, CFC Certificates and Bonds in the Working Capital calculation represent an inequitable, selective adjustment to increase rate base?

A. Yes. The Cooperative has ignored a large component of Working Capital (i.e., cash working capital) represented by revenues received and expenses paid. The impact on Working Capital of revenues and expenses can be calculated using a lead-lag study. A lead-lag study is recognized as the most accurate method to calculate cash working capital.

The Cooperative chose not to conduct a lead-lag study, and accordingly, omitted a major component of Working Capital. It is inequitable to ignore a major component of the Working Capital analysis and selectively recognize other components. Had a lead-lag study been conducted, it might have shown that Working Capital is a negative component of rate base.

Q. What factors imply that a lead-lag study could result in Working Capital being a negative component of rate base?

A. Interest and property tax expenses are components of a lead-lag study. The Cooperative has approximately $12 million in interest expense and $4 million in property taxes. The Cooperative collects cash used to make interest and property tax expense payments prior to the dates payment is due. For the period that AEPCO holds these funds before payment, they are a source of cost-free capital. If a lead-lag study were performed, this source of cost-free cash would be a significant negative factor in calculation of the net working capital.

Q. Does the Cooperative receive interest on the CFC Certificates and Bonds?

A. Yes. In response to CSB 3-3, the Cooperative received approximately $272,405 in interest income for these investments during the Test Year[17]. Therefore, including the CFC certificates and bonds in rate base would provide a second return on these investments.

Q. Did the Commission remove Prepayments and CFC Certificates and Bonds from rate base in AEPCO's prior rate case?

A. Yes, it did. The Commission removed prepayments in Decision No. 58405[18]. The Cooperative had not included CFC Certificates and Bonds in the rate base of that proceeding, therefore, it was not addressed in Decision No. 58405.

Q. What is Staff recommending for Prepayments and CFC Certificates and Bonds?

A. Consistent with Decision No. 58405, Staff recommends removal of Prepayments. Staff also recommends removal of CFC Certificates and Bonds from Working Capital as shown on Schedules CSB-3 and CSB-8.

Q. What is Staff's recommended adjustment to Working Capital?

A. Staff recommends decreasing Working Capital by $6,897,144 from $16,778,409 to $9,881,264 as shown on Schedules CSB-3 and CSB-8.

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[17] Per response to CSB 3-3, the $2.8 million Equity Term Certificates accrues interest at 5.00 % annually; the $1.3 million Series 1997C Subscription Term Certificates accrues interest at 7.57% annually; and the $795,000 Series 1994A Subscription Term Certificates accrues interest at 5.92% annually.

[18] Page 6, at line

Rate Base Adjustment 6 – Deferred Debit

Q. What amount in Deferred Debits is AEPCO proposing to include in Rate Base?

A. AEPCO is proposing $1,955,373 for Deferred Debits as shown on Schedule CSB-9. The amount is composed of $957,472 for preliminary survey and investigation charges, $731,780 for Job Tickets, and $266,121 for unamortized losses on reacquired debt.[19]

Q. Should these Deferred Debits be included in rate base?

A. No, they should not. The Deferred Debits balance consists of items that are not generally included in rate base. Preliminary survey and investigation charges and job tickets are a type of construction work in progress. Construction work in progress by definition is not used and useful.

Unamortized losses on reacquired debt present no future cash requirements for the Cooperative. Since Staff recommends a revenue requirement dependent on cash flow needs, there is no revenue requirement directly related to the carrying balance.

Including the unamortized loss on reacquired debt in rate base would be inequitable and serve only as a selective adjustment to augment rate base in the same manner as prepayments, CFC Bonds and Certificates.

Q. Did the Commission remove the deferred debit from rate base in AEPCO's prior rate case?

A. Yes, the Commission, in Decision No. 58405, removed the Deferred Debit from rate base.

[19] Per response to CSB 3-1

Q. What is Staff recommending?

A. Consistent with Decision No. 58405, Staff recommends removal of the Deferred Debit from Rate Base as shown on Schedules CSB-3 and CSB-9.

Rate Base Adjustment 7 –Asset Retirement Obligation ("ARO")

Q. What amount did AEPCO include in plant as an ARO?

A. AEPCO included a $1,962,630 ARO in its proposed plant. The Cooperative recorded the amount to "recognize the present value of its projected retirement cost"[20] associated with the retirement of an ash pond.

Q. What is an ARO?

A. In 2003, AEPCO adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligation* for purposes of financial statement presentation. Adoption of SFAS No. 143 represented a change in accounting principle for retirement of long-lived tangible assets with a legal obligation for disposal.

An asset retirement obligation is a liability recognized on the balance sheet for a legal obligation associated with the retirement of a long-lived tangible asset used in operations. Normally upon recognition of an ARO, an ARO asset and an ARO liability are recorded at the present value of the expected cost of disposal. The ARO liability grows as a cost of money factor (accretion expense) is applied to the ARO liability balance each period until the asset is retired. If the initial estimates were correct, the ARO liability will equal the cost at the time of disposal. The ARO asset is depreciated over the life of the asset. It is the ARO asset that AEPCO has included in plant.

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[20] Note 19 of AEPCO's 2003 audited financial statements

Q. Does AEPCO have any investment in the ARO asset it included in plant?

A. No. The ARO asset is merely an accounting entry to accommodate financial reporting requirements. AEPCO has no investment in the ARO asset it included in plant, and accordingly, has no basis for inclusion in rate base.

Q. For what asset did AEPCO recognize an ARO?

A. AEPCO recognized an ARO pertaining to a coal ash pond. The Cooperative plans to retire the ash pond in 2006, and estimates the disposal cost to be about $4 million. The Cooperative plans to obtain a loan to finance the disposal cost.

Q. Is the Commission committed to using financial accounting to rate-making purposes?

A. No. The Commission is not compelled to follow financial statement accounting for rate-making purposes. In this instance, following financial accounting is inappropriate because it recognized plant that is simply an accounting entry with no investment by AEPCO.

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $1,962,630 as shown on Schedules CSB-3 and CSB-10. Staff also recommends no change in the rate-making treatment of retirements with legal obligations.

OPERATING INCOME – AEPCO

Operating Income Summary – AEPCO

Q. What are the results of Staff's analysis of Test Year revenues, expenses and operating income?

A. As shown on Schedules CSB-11 and CSB-12 Staff's analysis resulted in Test Year revenues of $139,288,146, expenses of $128,306,372 and operating margin of $10,981,774.

Operating Income Adjustment No. 1 – Post-Test Year Revenue and Expenses

Q. What post-Test Year revenue and expense adjustments is AEPCO proposing?

A. AEPCO is proposing the following post-Test Year revenue and expense adjustments.

Post-Test Year Revenue and Expense Adjustments For Coal Blending Facility					
	AEPCO Adj. No. 5 Fuel Expense	AEPCO Adj. No. 6 SO2 Allowance	AEPCO Adj. No. 7 Ash Sales Credit	AEPCO Adj. No. 8 Coal Blender (Depreciation & Prop Taxes)	Total
Revenues	($ 551,934)	$ 0	$ 0	$ 0	($551,934)
Expenses	($1,534,274)	($167,069)	$820,611	$472,749	($407,983)
Operating Margin	$ 982,340	$167,069	($820,611)	($472,749)	($143,951)
Interest on L-T Debt	$ 0	$ 0	$ 0	$532,465	($532,465)
Total	$ 982,340	$167,069	($820,611)	($1,005,214)	($676,416)

Q. Why did the Cooperative propose a pro forma adjustment for PTY expenses?

A. The Cooperative proposed an adjustment to reflect its projection of operating expenses related to PTY plant additions.

Q. When would recognition of expenses related to PTY be appropriate?

A. The operating expenses related to PTY plant should be recognized only when the PTY plant is recognized and the affect on expenses is known and measurable. This means that all of the criteria for recognizing PTY plant must first be met before any related expense adjustment is recognized. This is essential to preserve the matching principle as previously discussed in Staff's testimony regard the adjustment to PTY plant.

Q. What treatment does Staff recommend for the Cooperative's pro forma adjustment for PTY expenses?

A. Since Staff recommends disallowance of the PTY plant, Staff also recommends disallowance of the Cooperative's pro forma post-test year adjustment to expenses.

Q. What is Staff recommending?

A. Staff recommends increasing operating revenue and expenses by $551,934 and $407,983, respectively, for a $143,951 net increase to operating margin as shown on Schedules CSB-12 and CSB-13.

Operating Income Adjustment No. 2 – Revenue and Expense Annualizations

Q. What is the purpose of a revenue and expense annualizations?

A. Revenue and expense annualizations are made to achieve matching with the year end rate base measurement date. The adjustments reflect the known and measurable changes to Class A members' customer counts during the Test Year. Revenues are annualized to reflect sales that would have occurred if customers on the system at the end of the Test Year had taken service for the entire year. Likewise, variable expenses are annualized to reflect the increased costs to provide the level of sales related to year end customers.

Q. Has Staff analyzed growth in the number of customers served by AEPCO's Class A Members?

A. Yes. Staff's analysis found that the number of customers grew at a rate of 3.29 percent from 2002 to 2003.

Q. Staff calculated a 3.29 percent growth rate. How was the growth rate used to annualize the revenues and expenses to end of year level?

A. Assuming the growth rate of 3.29 percent takes place evenly over the course of the year, then a 1.65 percent adjustment is needed to annualize sales growth to the end of the Test Year.

To illustrate: At the beginning of the year, Class A Members had a total of 116,074 customers as shown on Schedule CSB-14 line 14. At the end of the year, the actual number of customers was 119,895 as shown on Schedule CSB-14, line 15. To annualize the sales based on year-end customers, an adjustment of 1.65 percent [((119,895-116,074)/ 116,074) / 2] is necessary.

Q. What is Staff recommending?

A. Staff recommends increasing revenues by $1,271,908 and expenses by $264,376 as shown on Schedules CSB-12 and CSB-14.

Operating Income Adjustment No. 3 – Asset Retirement Obligation

Q. What effects of adopting SFAS No. 143 is AEPCO proposing as expenses?

A. AEPCO proposes $69,446 for operating expenses which represents depreciation of the ARO asset, and $191,564 for interest expense which represents accretion expense on the ARO liability, and $381,034 for interest expense which represents a ten-year amortization of a $3,810,335 write-off to record the cumulative effect of a change in accounting principle upon adoption of SFAS No. 143.

Q. Does AEPCO have any investment is the ARO asset upon which it recorded $69,446 of depreciation expense?

A. No. As previously discussed, the ARO asset is merely an accounting entry to accommodate financial reporting requirements. AEPCO has no investment in the ARO asset it included in plant, and accordingly, there is no asset cost to be recovered through depreciation.

Q. How did AEPCO record the adoption of SFAS No. 143 on its books?

A. According to Note 19 of AEPCO's 2003 audited financial statements, AEPCO "recorded the cumulative effect of the accounting change, totaling $3,810,335 in the consolidated statements of revenues and expenses and unallocated accumulated margins. The Cooperative also recognized the present value of its projected asset retirement costs, totaling $1,962,630, as a component of its capitalized utility plant on the consolidated balance sheets. Subsequently, the Cooperative recognized accretion[21] of the liability, totaling $185,802, as a component of interest expense and depreciation of the asset retirement costs, totaling $69,445, as depreciation expense[22] . . ."

As previously mentioned, AEPCO recognized the cumulative effect of implementing SFAS No. 143 on its financial statements in accordance to GAAP. The cumulative effect appears as a $3.8 million below-the-line extraordinary item on the 2003 income statement. The purpose of the $3.8 million below-the-line write-off is to adjust the financial statements so that they appear as if the requirements of SFAS No. 143 had always been followed. The write-off is a one-time, non-cash, nonrecurring expense that relates to past accounting periods.

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[21] Accretion expense is a type of interest expense that is added to the ARO liability annually to account for the time value of money.
[22] The ARO asset is depreciated over the life of the associated tangible asset.

Q. What rate-making treatment does AEPCO propose for the $3.8 million write-off?

A. AEPCO proposes to recover the $3.8 million write-off by including one-tenth, or $381,034, in operating expenses over a ten-year period.

Q. Is AEPCO's proposed treatment of the $3.8 million write-off consistent with rate-making principles?

A. No. The $3.8 million write-off pertains to past accounting periods. Recovery of expenses from prior periods is retro-active rate-making.

Q. Did AEPCO experience any cash outlay related to the $3.8 million write-off during the Test Year?

A. No. The write-off is simply an accounting entry used to implement a change in account principle to adopt SFAS No. 143.

Q. If implementation of SFAS No. 143 is not recognized how would AEPCO recover the ash pond disposal cost?

A. AEPCO could either have requested authorization to recover the disposal cost through depreciation expense or it can recognize an adjustment to rate base for the disposal cost upon retirement of the pond.

Q. Could AEPCO's proposed treatment result in excess recovery of the $3.8 million write-off?

A. Yes. Since AEPCO intends to finance the ash pond disposal cost with debt financing, the principle and interest costs will be reflected in the revenue requirements in future rate proceedings. If the $381,034 is simultaneously being recovered as an operating expense in the ten-year amortization period, an over-recovery would occur.

Q. Is there a relationship between the proposed amortization of the ARO write-off and the ARO plant that AEPCO included in rate base?

A. Yes. The ARO plant and the write-off are both associated with the implementation of SFAS No. 143. Staff's recommendation against recognition of the write-off is consistent with its recommendation not to recognize the ARO plant.

Q. Please summarize why the $381,034 ARO write-off should not be included in calculation of the revenue requirement.

A. The ARO write-off is no more than an accounting entry for implementing a change in accounting principle for financial statement purposes. It is a one-time, non-cash charge pertaining to prior periods. Recognition of the proposed ten-year amortization of the write-off would be retro-active rate-making and lead to potential over-recovery.

Q. What is Staff recommending?

A. Staff recommends removing all effects of the ARO on the income statement including $69,446 from operating expenses and $572,598 from Interest and Other Deductions as shown on Schedules CSB-12 and CSB-15.

Operating Income Adjustment No. 4 – Tracker Mechanism (Base Power Cost)

Q. Explain the purpose of the break-out of the Total Class A Member Revenue into two components as shown is Schedules CSB-11 and -12.

A. The purpose is to show separately the portion of revenue that represents costs that flow through the tracker mechanism as proposed by Staff.

Q. What revenue would AEPCO recover through its proposed adjustor rate of $0.02038 per kWh?

A. The Cooperative would collect $41,276,155 (2,025,326,533[23] kWhs x $0.02038[24] per kWh) for generated and purchased power cost as shown on Schedule CSB-16, line 7. This is equal to the Cooperative's proposed base cost of power as shown on Schedule CSB-16, line 53.

Q. Is Staff recommending a different level of base power costs?

A. Yes. The Staff adjusted base power cost is $33,560,400 as shown on Schedule CSB-16, line 53.

Q. What adjustment did Staff make to revenue to recognize the $7,716,227 difference between Staff and AEPCO's base power costs?

A. Staff reclassified $7,716,227 from Base Cost of Power Revenue to Non-Base Cost of Power Revenue. This adjustment has no impact on the revenue requirement. The adjustment simply shows separately the amount of Test Year revenue reflected by Staff's proposed level for base power costs.

Q. Did Staff disallow any costs from the accounts included in the base cost of power expense?

A. Yes, Staff annualized the savings from a new contract that was in effect for only half of the Test Year. Staff decreased base cost of power expense by $250,000 as shown on Schedules CSB-16, line 27 and CSB-12, line 13.

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[23] Cooperative Schedule H 2A, Line 36
[24] Cooperative Schedule H 2A, Line 38

Operating Income Adjustment No. 5 – Overhaul Accrual Expense

Q. Why are generation unit overhauls needed?

A. A generation unit consists of thousands of separate components that deteriorate at different rates based on operating conditions. The overhaul of one of these complex units encompasses a wide range of preventative maintenance, repair, and replacement activities that are needed to help ensure safe and reliable operation.

Q. What is AEPCO proposing for overhaul accrual expense?

A. AEPCO is proposing $4,787,507 for overhaul accrual expense[25].

Q. What was AEPCO's actual overhaul expense during the Test Year?

A. AEPCO's actual overhaul expense was $3,148,905[26].

Q. Why are the actual and accrual expenses different?

A. The actual overhaul expense is not representative of the overhaul expense from year to year because the nature and scope of overhauls vary from year to year based on operating conditions. Consequently, the Cooperative estimates and accrues an amount for the annual overhaul expense. In 2003, AEPCO began using a revised methodology to calculate its overhaul accruals.

Q. Does Staff agree that the overhaul accrual expense included in rates should be based upon the AEPCO's revised methodology?

A. No. AEPCO's revision to the method by which it has previously calculated overhaul accrual expense significantly increased the accrual from the prior year. The Cooperative's

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[25] Per response to data request CSB 1-38
[26] Per response to data request CSB 1-38

overhaul accrual expense increased by approximately $2 million, from $2.79 million in 2002 to $4.79 million in 2003 (CSB 1-37). The accruals are estimates based on complex projections for which AEPCO has no actual experience.

Q. What method does Staff recommend for calculating the accrual amount?

A. Staff recommends calculating the accrual expense as the eight year average[27] of the actual overhaul expense as shown on Schedule CSB-17. Eight years is representative of the typical overhaul period.

Q. What is Staff recommending?

A. Staff recommends decreasing overhaul accrual expense by $657,788, from $4,787,508 to $4,129,720 as shown on Schedules CSB-12 and CSB-17.

Operating Income Adjustment No. 6 – Transmission Expense Annualization

Q. What is the Cooperative proposing for transmission expense?

A. AEPCO is proposing $8,036,486 for transmission expense. This amount is composed of $6,692,293 of actual Test Year transmission expense; a ($245,438) pro forma adjustment to reflect termination of the City of Mesa contract and; a $1,589,631 pro forma adjustment to reflect the annualization of transmission expense for its (a) wheeling expenses associated with a Western Area Power Administration agreement and (b) an El Paso Palo Verde agreement and (c) the proposed increase in point-to-point transmission rates that Southwest Transmission charges AEPCO.

[27] Per response to CSB 1-38, major overhauls occur approximately every 96 months for base load generating units.

Q. Does Staff recommend a different Point-to-Point rate than that recommended by Southwest Transmission?

A. Yes, Staff recommends a different rate as shown on Schedule CSB-18. Staff recommends a $3.022 Point-to-Point rate, a decrease of $0.010 below the Cooperative's $3.032 rate. Staff's recommended Point-to-Point rate for Southwest Transmission will result in a lower transmission expense for AEPCO.

Q. What is Staff recommending?

A. Staff recommends decreasing transmission expense by $19,560 as shown on Schedule CSB-18.

Operating Income Adjustment No. 7 – Normalized Legal Expense

Q. What is AEPCO proposing for Outside Services Legal Expenses?

A. AEPCO is proposing $903,512[28] for Outside Services Legal Expenses as shown on Schedule CSB-19. The Cooperative's 2003 legal expense report shows total legal expenses of $2,695,758 comprised of $903,512 for Outside Services and $1,792,246[29] for related to the railroad transportation tariff.

Q. What approach did Staff take for evaluating legal expenses?

A. Staff recognized that legal expenses can vary significantly from year-to-year. Accordingly, Staff calculated a normalized cost by averaging the allowable costs for the years 2002, 2003 and 2004. This required making adjustments to remove costs determined to be unallowable from each of those years. For convenience, Staff calculated the normalized railroad transportation tariff legal expense separately from other legal expenses.

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[28] Per data request response to CSB 13-1.
[29] Per data request response to CSB 13-1.

Normalized Railroad Transportation Legal Expense

Q. How did Staff calculate the normalized railroad transportation tariff legal expense?

A. Staff normalized this expense by amortizing the total of the 2002, 2003, and 2004 costs related to the railroad transportation tariff over the five-year contract term (i.e., expected benefit period) as shown on Schedule CSB-19.1. The $1,792,246 expense for 2003 includes the $1,030,873 reclassified from fuel expense as discussed in Operating Income Adjustment No. 8, "Fuel Expense." The calculation is presented on Schedule CSB-20, line 22.

Q. What amount is Staff recommending for the normalized railroad transportation tariff portion of legal expense?

A. Staff recommends $620,129 for the normalized railroad transportation tariff portion of legal expense as shown on Schedule CSB-19, line 6.

Normalized Outside Services (Non-Railroad Transportation Tariff) Legal Expenses

Q. Has Staff prepared an explanation for each amount it excluded from the 2003 costs in its calculation of the normalized non-railroad transportation legal expenses as shown on Schedule CSB-19.2?

A. Yes. An explanation of each type of cost excluded from Staff's normalization adjustment is presented below.

Natural Gas Related Legal Expenses

Q. How are costs allocated between the three cooperatives (AEPCO, Southwest Transmission, and Sierra Southwest)?

A. According to the cooperatives' cost allocation manual, "Anything not specifically ascribed to AEPCO or SWTransCo activities" is allocated. AEPCO's composite allocation rate for legal expenses is 80.23 percent.

Q. Did AEPCO receive 80.23 percent of the natural gas-related legal expenses based on the three-entity allocation factor?

A. No. Virtually all of the $354,824 in natural gas-related legal expenses were direct charged to AECPO with no allocation to the two other entities.

Q. Does Staff agree that virtually all natural gas-related legal expenses should be directly charged to AEPCO?

A. No. Direct charging these legal costs to AEPCO is inappropriate because Sierra Southwest, the unregulated cooperative, is a wholesale gas seller/marketer with several wholesale natural gas contracts (including Duncan Rural Service, Corporation; a California town, and the City of Tucson) would potentially benefit from related legal services. Appropriate allocation of natural gas related legal expenses is necessary to ensure that there is no subsidy of Sierra Southwest's unregulated business activities by AEPCO's ratepayers. Control procedures should be adopted to ensure that proper allocations are recognized.

Q. What amount of natural gas-related legal costs has Staff excluded from its calculation of normalized legal expense?

A. Staff allocated the $354,824 cost by the current three-entity allocation factor (80.23 percent) to calculate $284,675 as AEPCO's allocation resulting in a $70,149 ($354,824-$284,675) exclusion from the normalization calculation shown on Schedule CSB-19.2, line 2.

El Paso Electric Company Contract Related Legal Expenses

Q. What is the El Paso Electric Company contract?

A. The El Paso Electric Company ("EPE") contract is a long-term transmission service agreement between AEPCO and El Paso Electric Company. The Cooperative plans to use the EPE contract in conjunction with the Panda Gila Purchase Agreement to reduce its fuel costs for the three-year period 2005 through 2008.

Q. Is it appropriate to charge all of the costs of a contract that will benefit multiple years to the Test Year?

A. No. Costs that result in multi-year benefits should be distributed on the benefit period. Accordingly, Staff amortized the approximate $34,773 in legal expenses related to El Paso Electric Company over three years to recognize $11,591 per year.

Q. What amount of EPE contract-related legal costs has Staff excluded from its calculation of normalized legal expense?

A. Staff excluded $23,182 ($34,773 - $11,591) from the normalization calculation shown on Schedule CSB-19.2, line 3.

Public Utilities Holding Company Act ("PUHCA")

Q. Was a primary purpose of the Public Utilities Holding Company Act to address the subsidization of non-regulated affiliates by regulated utilities?

A. Yes.

Q. Was AEPCO charged for any legal expenses related to the Public Utilities Holding Company Act?

A. Yes. AEPCO was charged for the legal expenses related to the Securities Exchange Commission's inquiry of Sierra Southwest's business activities. When Staff requested to review documents related to this issue, AEPCO objected citing the attorney-client privilege. In response to data request CSB 5-15, the Cooperative indicated that $15,500 in legal expenses related to PUHCA were improperly charged to AEPCO.

Q. How did Staff treat these PUCHA legal costs in its calculation of normalized legal expenses?

A. Staff excluded $15,500 in legal expenses related to PUHCA in its calculation of normalized legal expense as shown on Schedule CSB-19.2, line 4.

Q. Does AEPCO's denial of access to records provide concerns beyond whether these legal costs are related to the provision of utility service and recoverable?

A. Yes. Beyond the issue of whether the legal costs were incurred for utility purposes, the lack of access to records raises a question as to whether other significant issues related to the revenue requirement went undiscovered.

Q. Does Staff have any other recommendations regarding redacted issues?

A. Yes. In this case, Staff was unable to quantify and remove payroll costs of all employees, outside services staff, and members of the Board of Directors who spent time working on the redacted issues. Staff recommends that in future rate proceedings AEPCO be required to quantify all payroll costs of employees, outside services staff, and members of the Board of Directors fees related to time spent on redacted issues.

Capitalized Expenses

Q. Did AEPCO capitalize any of legal expenses in 2003?

A. Yes. AEPCO capitalized $13,605 of legal expenses in 2003.

Q. How did Staff treat these capitalized legal costs in its calculation of normalized legal expenses?

A. Staff excluded the $13,605 capitalized legal cost from its calculation of normalized legal expense as shown on Schedule CSB-19.2, line 5.

Redacted Minutes and Legal Invoices

Q. Did AEPCO fail to support any of its legal expenses?

A. Yes, AEPCO objected to the release of certain portions of the Minutes of the Executive Session of the Board of Directors and legal invoices citing the attorney-client privilege. Therefore, the appropriateness of the costs could not be substantiated.

Q. Did Staff inform AEPCO of the likely consequence of not providing the requested information?

A. Yes, in a letter to the Cooperative dated September 29, 2004, Staff indicated that failure to provide complete legal invoices would result in a disallowance of such costs.

Q. What was the total amount of expenses related to the redacted legal invoices and minutes that Staff excluded from its calculation of normalize legal expense?

A. Staff excluded $68,412[30] from its calculation of normalized legal expense as shown on Schedule CSB-19.2, line 6.

[30] For the Slover and Loftus legal invoices, Staff estimated the expenses related to the redacted issues based upon the number of general groups of issues on an invoice. The total amount billed on the invoice was divided by the number of general groups. For all other redacted invoices, Staff multiplied the total invoice amount by 15 percent.

Q. What is Staff recommending for normalized legal expense?

A. Staff recommends $620,129 and $823,372 for railroad and non-railroad transportation tariff legal expenses, respectively, for a total of $1,443,501. This amount is $539,989 greater than the $903,512 proposed by AEPCO, as shown on Schedules CSB-12 and CSB-19, line 11.

Operating Income Adjustment No. 8 – Fuel Expense

Q. What is AEPCO proposing for fuel expense?

A. AEPCO is proposing $59,803,425 for fuel expense as shown on Schedule CSB-12, line 9. The amount is composed of $44,521,523 for coal and $15,281,902 for gas and other fuel sources.

Q. Does the $44,521,523 in fuel expense for coal include legal expenses?

A. Yes, it does. The $44,521,523 is calculated using a weighted average cost of coal. The weighted average cost of coal includes legal expenses. A summary of the Cooperative's calculation of the $44,521,523 provided in response to data request CSB 3-14 is presented on Schedule CSB-20. Staff segregated the legal expense included in the weighted cost of coal on line 9.

Q. Did the Commission remove legal expense from fuel costs in the Cooperative's prior rate proceeding?

A. Yes, the Commission removed legal expense from fuel costs in the prior rate proceeding. AEPCO had included all fuel expenses including legal in its purchased power fuel adjustor. The Commission removed these costs in the prior rate proceeding indicating that its inclusion was inappropriate.[31]

[31] Decision No. 58405, page 28, lines 22 through 26, and page 29, lines 1 through 6.

Q. Did Staff calculate the amount of legal expense included in fuel expense?

A. Yes. Staff calculated that fuel cost includes $1,030,873 legal expenses as shown on Schedule CSB-20, line 24.

Q. How did Staff treat the legal expenses embedded fuel costs?

A. Staff reclassified these legal expenses and included them in its calculation of normalized legal expenses as shown on Schedule CSB-19, line 2.

Q. Did Staff find any other costs in the Cooperative's proposed fuel expense for which it recommends alternate treatment?

A. Yes. Included in the fixed costs the Cooperative allocated to coal fuel costs is $22,200 of interest on long-term debt. Staff removed this interest expense from fuel costs, as shown on Schedule CSB-20, line 22, because Staff is recognizing recovery of interest expense separately.

Q. What is Staff recommending?

A. Staff recommends decreasing fuel expense by $1,053,073 as shown on Schedules CSB-12 and CSB-20.

Operating Income Adjustment No. 9 – Advertising

Q. What is AEPCO proposing for advertising expense?

A. AEPCO is proposing $46,241 for advertising expense.

Q. Are these advertising costs necessary for safe and reliable service?

A. No, these costs are not necessary to provide safe and reliable service. AEPCO is a regulated electric service provider. Consequently, there is no reason to recover advertising costs incurred primarily for image building that may otherwise make economic sense for a firm selling services in an open competitive market.

Q. What rate-making treatment does Staff recommend for these advertising costs?

A. Staff recommends that these costs be recognized below-the-line (removed from rates).

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $46,241 as shown on Schedules CSB-12 and CSB-21.

Operating Income Adjustment No. 10 – Charitable Contributions and Other Expenses

Q. What is AEPCO proposing for contributions, sponsorships, food, entertainment and similar expenses?

A. AEPCO is proposing $159,891 for contributions, sponsorships, food, entertainment, and similar expenses as shown on Schedule CSB - 22.

Q. What ratemaking treatment does Staff recommend for these types of expenses?

A. Since these costs are not necessary to provide service, Staff recommends that they be recognized as non-operating expenses and excluded from the revenue requirement.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $159,891 as shown on Schedules CSB-12 and CSB-22.

Operating Income Adjustment No. 11 – Arizona Corporation Commission Gross Revenue Assessment

Q. What is the Cooperative proposing for the ACC assessment?

A. The Cooperative included $147,146 in operating revenue and $288,752 in operating expense for the ACC assessment.

Q. What does Decision No. 58405 state concerning the ACC assessment for AEPCO?

A. On footnote 9 of page 17, the Commission states that "The gross revenue tax will in the future be recovered through a bill add-on." Therefore, the assessment should not be included in the cost of service.

Q. What is Staff recommending?

A. Staff recommends decreasing operating revenue by $147,146 and operating expense by $288,752 to remove the effects of the ACC assessment as shown on Schedules CSB-12 and CSB-23.

Income Adjustment No. 12 (Non-Operating) – Interest Expense on Long-term Debt

Q. What is the Cooperative proposing for Interest Expense on Long-term Debt?

A. AEPCO is proposing $13,547,749 for Interest Expense on Long-term Debt as shown on Schedule CSB-24. The amount is composed of $12,200,997 in actual interest expense and proforma adjustments totaling $1,346,752 (Cooperative adjustment numbers 8, 9, and 13 in the amounts of $532,465, $1,190,178, and ($375,891), respectively).

Q. Did Staff make an independent assessment of the Cooperative's Interest Expense on Long-term Debt?

A. Yes. Staff witness Alejandro Ramirez independently calculated $13,313,164 as the Cooperative's interest expense on long-term debt and prepared testimony to support his calculation.

Q. What adjustment did Staff make to Interest Expense on Long-term Debt?

A. Staff decreased Interest Expense on Long-term Debt by $234,585 as shown on Schedules CSB-12 and CSB-24.

Deferred Fuel-Related Legal and Pension Expense

Q. Staff noted that Decision No. 58405 authorized AEPCO to establish two deferral accounts. Would you please discuss the background of the deferral accounts?

A. Yes. Fuel related legal costs and pension costs were not included in the cost of service in AEPCO's prior rate proceeding (Decision No. 58405, page 29, beginning at line 2). Subsequently, the Commission ordered AEPCO to establish two deferral accounts: one for fuel related legal expenses and a second deferral account for actual pension costs for possible recovery in a future rate proceeding (Decision No. 58405, Page 37, beginning at line 5).

Q. What were the balances for the fuel-related Legal and Pension expenses as of December 31, 2003?

A. AEPCO had not recorded any amounts related to the deferrals as of December 31, 2003, because the recovery of the deferrals were uncertain (CSB 3-2). However, the Cooperative indicated that it had accumulated $5,839,957 in required NRECA pension fund contributions and $3,722,948 in legal expenses associated with fuel costs, for a total of $9,562,905 (CSB 6-3).

Q. What treatment does Staff recommend for the $9.5 million unrecorded Legal and Pension deferrals?

A. Staff recommends not including the unrecorded deferrals in rates. The revenue requirement for the Cooperative is based primarily on cash flow needs, and there are no cash requirements going forward for these costs from prior periods that were deferred. Since AEPCO did not record the deferrals, there would be no write-down and associated negative effect on the Cooperatives patronage equity due to non-recovery.

Q. Does Staff recommend that the deferrals continue?

A. Since the cost of service in the instant case includes costs for fuel related legal expenses and pension, Staff recommends that the deferrals be discontinued.

Jurisdictional Separation

Q. Did AEPCO maintain separation between Commission jurisdiction and non-jurisdiction revenues and expenses?

A. No, it did not. The Cooperative serves a California member for which separate revenues and expenses were not maintained.

Q. Is the Cooperative required to maintain separation of the revenues and expenses for the California member?

A. Yes, it is. The Arizona Administrative Code R14-2-103 B4 states the following:

> Separation of nonjurisdictional properties, revenues and expenses associated with the rendition of utility service not subject to the jurisdiction of the

Commission must be identified and properly segregated in a recognized manner when appropriate.

Q. Can Staff identify some cooperatives that provided jurisdictionally separated information in their rate filings?

A. Yes. Duncan Valley Electric Cooperative, Inc. and Garkane Power Association, Inc. provide jurisdictionally separated information in compliance with the Administrative Code. These cooperatives generate much smaller revenues than AEPCO. The jurisdictionally separated financial information helps to verify that Arizona ratepayers are not paying more than their fair share of the cost of providing service.

Q. What is Staff recommending?

A. Staff recommends that the Cooperative comply with Arizona Administrative Code R14-2-103 B4 in its next rate filing.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION		[A] COMPANY ORIGINAL COST		[B] STAFF ORIGINAL COST
1	Adjusted Operating Income (Loss)	$	7,972,676	$	10,981,774
2	Depreciation and Amortization	$	7,608,735	$	7,539,289
3	Income Tax Expense		-		-
4	Long-term Interest Expense	$	13,547,749	$	13,313,164
5	Principal Repayment	$	10,344,950	$	14,360,494
6a	**Recommended Increase in Operating Revenue**	$	8,450,016	**$**	**6,773,320**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**		N/A		**4.86%**
6c	Percent Increase (Line 6a / $85,685,624) - Per Coop		9.86%		N/A
7	Adjusted Test Year Operating Revenue	$	137,611,450	$	139,288,146
8	**Recommended Annual Operating Revenue**	$	146,061,466	**$**	**146,061,466**
9a	**Recommended Operating Margin**	$	16,422,692	**$**	**17,755,094**
9b	Recommended Net Margin	$	3,922,406	$	4,099,540
10a	**Recommended Operating TIER (L3+L9)/L4 - Per Staff**		N/A		**1.33**
10b	Recommended Net TIER (L4+L9b)/L4 - Per Coop		1.29		N/A
11a	**Recommended DSC (L2+L3+L9)/(L4+L5) - Per Staff**		N/A		**0.91**
11b	Recommended DSC (L2+L4+L9b)/(L4+L5) - Per Coop		1.05		N/A
12	**Adjusted Rate Base**	$	222,147,011	**$**	**189,637,810**
13	Rate of Return (L9a / L12)		7.39%		9.36%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules CSB-2, CSB-11, Testimony Alejandro Ramirez

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Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Plant in Service	$ 389,603,749	$ (11,928,486)	$ 377,675,263
2	Less: Acc Depreciation & Amortization	(186,190,519)	253,883	(185,936,636)
3	Net Plant in Service	$ 203,413,230	$ (11,674,603)	$ 191,738,627
	LESS:			
4	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -	$ -
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	$ -	$ -	$ -
9	Member Advances	$ -	$ (11,982,081)	$ (11,982,081)
	ADD:			
10	Working Capital	$ 16,778,408	$ (6,897,144)	$ 9,881,264
11	Plant Held for Future Use	$ -	$ -	$ -
12	Deferred Debits	$ 1,955,373	$ (1,955,373)	$ -
13	**Total Rate Base**	$ 222,147,011	$ (32,509,201)	$ 189,637,810

References:
Column [A], Company Schedule B-1, Page 1
Column [B]: Schedule CSB-3
Column [C]: Column [A] + Column [B]

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Schedule CSB-3

SUMMARY OF RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] Coal Blending Plant ADJ No.1	[C] Plant Acquisition Adjustment ADJ No. 2	[D] Accumulated Depreciation ADJ No. 3	[E] Member Advances ADJ No. 4	[F] Working Capital ADJ No. 5	[G] Deferred Debits ADJ No. 6	[H] ARO ADJ No. 7	[I] STAFF ADJUSTED
	PLANT IN SERVICE:									
1	Intangible Plant[1]	$ 18,527 [1]	$ -	$ (13,238)	$ -	$ -	$ -	$ -	$ -	$ 5,289
2	Steam Production Plant - Land and Land Rights	3,915,175	-	-	-	-	-	-	-	3,915,175
3	Steam Production Plant - Structures and Improv	34,923,477	-	-	-	-	-	-	-	34,923,477
4	Steam Production Plant - Boiler Equipment	202,166,807	-	-	-	-	-	-	-	202,166,807
5	Steam Production Plant - Turbine Generators	51,884,782	-	-	-	-	-	-	-	51,884,782
6	Steam Production Plant - Misc Electrical Equip[2]	21,531,578 [2]		-	-	-	-	-	-	21,531,578
7	Steam Production Plant - Asset Retirement Oblig	1,962,630	-	-	-	-	-	-	(1,962,630)	-
8	Other Production Plant - Land and Land Rights	1,160	-	-	-	-	-	-	-	1,160
9	Other Production Plant - Structures and Improv	10,591,888	(9,952,618)	-	-	-	-	-	-	639,270
10	Other Production Plant - Fuel Hldrs Prodcrs & Acces	2,805,026	-	-	-	-	-	-	-	2,805,026
11	Other Production Plant - Prime Movers	29,153,230	-	-	-	-	-	-	-	29,153,230
12	Other Production Plant - Generators	3,284,797	-	-	-	-	-	-	-	3,284,797
13	Other Production Plant - Misc Electrical Equip[3]	3,361,517 [3]	-	-	-	-	-	-	-	3,361,517
14	Transmission Plant - Station Equipment	2,524,442	-	-	-	-	-	-	-	2,524,442
15	Transmission Plant - Poles, Fixtures, Conductors[4]	247,329 [4]	-	-	-	-	-	-	-	247,329
16	General Plant[5]	17,278,108 [5]	-	-	-	-	-	-	-	17,278,108
17	Unclassified Completed Construction - General Plant	3,943,249	-	-	-	-	-	-	-	3,943,249
18	Unclassified Completed Constr - Steam, Generation	10,027	-	-	-	-	-	-	-	10,027
19	Total Plant in Service	$ 389,603,749	(9,952,618)	(13,238)	-	-	-	-	(1,962,630)	$ 377,675,263
20	Less: Accumulated Depreciation	$ (185,972,877)	-	-	253,883	-	-	-	-	$ (185,718,994)
21	Less: Accumulated Amortization	(217,642)	-	-	-	-	-	-	-	(217,642)
22	Total Accumulated Depreciation & Amortization	$ (186,190,519)	$ -	$ -	$ 253,883	$ -	$ -	$ -	$ -	$ (185,936,636)
23	Net Plant in Service	$ 203,413,230	$ (9,952,618)	$ (13,238)	$ 253,883	$ -	$ -	$ -	$ (1,962,630)	$ 191,738,627
	LESS:									
24	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Contributions in Aid of Construction (CIAC)	-	-	-	-	-	-	-	-	-
26	Less: Accumulated Amortization	-	-	-	-	-	-	-	-	-
27	Net CIAC	$ -	-	-	-	-	-	-	-	$ -
28	Member Advances	$ -	-	-	-	(11,982,081)	-	-	-	$ (11,982,081)
	ADD:									-
29	Working Capital Allowance	$ 16,778,408	-	-	-	-	(6,897,144)	-	-	$ 9,881,264
30	Plant Held For Future Use	-	-	-	-	-	-	-	-	-
31	Deferred Debits	1,955,373	-	-	-	-	-	(1,955,373)	-	-
32	**Total Rate Base**	$ 222,147,011	$ (9,952,618)	$ (13,238)	$ 253,883	$ (11,982,081)	$(6,897,144)	$ (1,955,373)	$ (1,962,630)	$ 189,637,810

ADJ No.		References:
1	Coal Blending Plant	Schedule CSB-4
2	Plant Acquisition Adjustment	Schedule CSB-5
3	Accumulated Depreciation	Schedule CSB-6
4	Member Advances	Schedule CSB-7
5	Working Capital	Schedule CSB-8
6	Deferred Debits	Schedule CSB-9
7	Asset Retirement Obligation ("ARO")	Schedule CSB-10

Footnote Explanations
[1] Includes account nos. 301,114,302, & 303
[2] Includes account nos. 315 & 316
[3] Includes account nos. 345 & 346
[4] Includes account nos. 355 & 356
[5] Includes account nos. 389 and 390 to 399

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Schedule CSB-4

RATE BASE ADJUSTMENT NO. 1 - POST-TEST YEAR PLANT, COAL BLENDING FACILITY

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (Sch E-5)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	2003 Actual Plant	$ 379,651,131	$ -	$ 379,651,131
2	Coal Blending Facility (Acct. No. 341)	$ 9,952,618	$ (9,952,618)	$ -
		$ 389,603,749	**$ (9,952,618)**	**$ 379,651,131**

3 To remove plant that was not used and useful during the Test Year.

4 References:
5 Column [A]: Cooperative Schedule E-5, Page 1
6 Column [B]: Testimony, CSB
7 Column [C]: Column [A] + Column [B]

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Schedule CSB-5

RATE BASE ADJUSTMENT NO. 2 - ACQUISITION ADJUSTMENT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (Sch E-5)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Intangible Plant (Excluding Acquisition Adj)	$ 5,289	$ -	$ 5,289
2	Intangible Plant, Acquisition Adjustment	$ 13,238	$ (13,238)	$ -
	Total Intangible Plant	**$ 18,527**	**$ (13,238)**	**$ 5,289**

3 To remove unauthorized acquistion adjustment from plant in service.

4 References:
5 Column [A]: Cooperative Schedule E-5, Page 1
6 Column [B]: Testimony, CSB
7 Column [C]: Column [A] + Column [B]

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Schedule CSB-6

RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEPRECIATION

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Accumulated Depreciation	$ (185,718,994)	$ -	$ (185,718,994)
2	Accumulated Depr, Retirement Work In Progress	$ 54,648	$ (54,648)	$ -
3	Accumulated Depreciation, Coal Blending Plant	$ (308,531)	$ 308,531	$ -
4	**Total Accumulated Depreciation**	**$ (185,972,877)**	**$ 253,883**	**$ (185,718,994)**

5 References:
Column A: Cooperative Schedules B-2, Page 1 and E-5, Page 4

6 Column B: Testimony, CSB, Company Data Request Responses CSB 3-18 and CSB 3-19

7 Column C: Column [A] + Column [B]

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Schedule CSB-7

RATE BASE ADJUSTMENT NO. 4 - MEMBER ADVANCES

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Member Advances	$ -	$ (11,982,081)	$ (11,982,081)

LINE NO.		Member Advances Ending Balance (Per CSB 1-21)	Member Advances Average Balance
2			
3			
4			
5			
6			
7	Dec-02	$ (15,278,804.00)	
8	Jan-03	$ (14,437,497.22)	$ (14,858,150.61)
9	Feb-03	$ (16,543,558.64)	$ (15,490,527.93)
10	Mar-03	$ (12,513,460.14)	$ (14,528,509.39)
11	Apr-03	$ (10,947,970.04)	$ (11,730,715.09)
12	May-03	$ (11,848,040.63)	$ (11,398,005.34)
13	Jun-03	$ (10,325,533.24)	$ (11,086,786.94)
14	Jul-03	$ (10,003,125.98)	$ (10,164,329.61)
15	Aug-03	$ (11,283,568.22)	$ (10,643,347.10)
16	Sep-03	$ (11,769,769.82)	$ (11,526,669.02)
17	Oct-03	$ (9,930,963.36)	$ (10,850,366.59)
18	Nov-03	$ (6,373,504.03)	$ (8,152,233.70)
19	Dec-03	$ (2,529,176.16)	$ (4,451,340.10)
20		$(143,784,971.48)	$ (134,880,981.40)
21			/ 12
22			$ (11,982,080.96)

23 References:

24 Column [A]: Cooperative Schedule B-5, Page 1

25 Column [B]: Column C - Column A

26 Column [C]: Example calculation: Jan-03 = (Dec-02 + Jan-03) / 2; CSB 1-21

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Schedule CSB-8

RATE BASE ADJUSTMENT NO. 5 - WORKING CAPITAL

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Cash Working Capital	$ -	$ -	$ -
2	Fuel Stock, Coal	$ 5,581,933	$ (946,753)	$ 4,635,180
3	Materials and Supplies	$ 5,265,561	$ (19,476)	$ 5,246,085
4	Prepayments	$ 908,046	$ (908,046)	$ -
5	CFC Certificates and Bonds	$ 5,022,869	$ (5,022,869)	$ -
6	**Total Working Capital**	**$ 16,778,409**	**$ (6,897,144)**	**$ 9,881,265**

7 References:

8 Column A: Cooperative Schedule B-5, Page 1

9 Column B: Testimony, CSB; Schedules CSB-8.1 and CSB-8.2

10 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc. | Schedule CSB-8.1
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FUEL STOCK CALCULATION

Line No.	Number of Burn Days (CSB 3-15)	[A] Tons of Coal Burned Per Day (CSB 3-15)	[B] Average Cost Per Ton (CSB 6-9)	[C] Average Cost of Coal Inventory
1	42.5	4,100	$ 27.7	$ 4,826,725
2	**Less:** Legal expenses charge to fuel inventory (CSB 15-3)			$ (191,545)
3	Total Fuel Stock			$ 4,635,180

4 References:
5 Column [A]: Cooperative Response to CSB 3-15 & CSB 15-3
6 Column [B]: Cooperative Response to CSB 6-9
7 Column [C]: Column [A] x Column [B]

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Schedule CSB-8.2

MATERIALS AND SUPPLIES BALANCE CALCULATION

LINE NO.	END OF MONTH BALANCE	[A] COMPANY AS FILED 13-Month Avg	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED 12-Month Avg
1	Dec-02	$ 5,199,651	$ (5,199,651)	$ -
2	Jan-03	$ 5,170,130	$ 14,761	$ 5,184,891
3	Feb-03	$ 5,127,900	$ 21,115	$ 5,149,015
4	Mar-03	$ 4,896,182	$ 115,859	$ 5,012,041
5	Apr-03	$ 4,977,902	$ (40,860)	$ 4,937,042
6	May-03	$ 5,158,387	$ (90,243)	$ 5,068,145
7	Jun-03	$ 5,089,094	$ 34,647	$ 5,123,741
8	Jul-03	$ 5,318,376	$ (114,641)	$ 5,203,735
9	Aug-03	$ 5,313,413	$ 2,482	$ 5,315,895
10	Sep-03	$ 5,339,052	$ (12,820)	$ 5,326,233
11	Oct-03	$ 5,377,843	$ (19,396)	$ 5,358,448
12	Nov-03	$ 5,685,470	$ (153,814)	$ 5,531,657
13	Dec-03	$ 5,798,889	$ (56,710)	$ 5,742,180
14		$ 68,452,289	$ (5,499,270)	$ 62,953,019
15	Divided by	13	$ (1)	12
16		$ 5,265,561	$ (19,476)	$ 5,246,085

17 References:
18 Column [A]: Cooperative Schedule B-5, Pages 1 and 5
19 Column [B]: Testimony, CSB; Column C - Column A
20 Column [C]: Example calculation: Jan-03 = (Dec-02 + Jan-03) / 2

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Schedule CSB-9

RATE BASE ADJUSTMENT NO. 6 - DEFERRED DEBITS

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED (CSB 3-1)**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Preliminary Survey & Investigation Charges	$ 957,472	$ (957,472)	$ -
2	Job Tickets	$ 731,780	$ (731,780)	$ -
3	Unamortized Losses on Reacquired Debt	$ 266,121	$ (266,121)	$ -
4	Total Deferred Debits	**$ 1,955,373**	**$ (1,955,373)**	**$ -**

5 References:
6 Column [A]: Cooperative Schedule B-1, Line 8; CSB 3-1
7 Column [B]: Testimony, CSB
8 Column [C]: Column [A] + Column [B]

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Schedule CSB-10

RATE BASE ADJUSTMENT NO. 7 - ASSET RETIREMENT OBLIGATION ("ARO")

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (CSB 3-1)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Steam Production Plant - Asset Retirement Oblig	$ 1,962,630	$ (1,962,630)	$ -

2 References:
3 Column [A]: Cooperative Schedule E-5, Page 1, Line 12; Note 19 of Audited Financial Statements
4 Column [B]: Testimony, CSB
5 Column [C]: Column [A] + Column [B]

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OPERATING INCOME - TEST YEAR AND STAFF PROPOSED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 44,409,469	$ (6,591,465)	$ 37,818,004	$ 6,773,320	$ 44,591,324
2	Class A Members, Base Cost of Power Revenue	$ 41,276,155	$ 7,716,227	$ 48,992,382		$ 48,992,382
3	Total Class A Member Electric Revenue	$ 85,685,624	$ 1,124,762	$ 86,810,386	$ 6,773,320	$ 93,583,706
4	Non-Class A, Non-Firm, & Non-Member	50,444,504	551,934	50,996,438	-	50,996,438
5	Total Electric Revenue	$ 136,130,128	$ 1,676,696	$ 137,806,824	$ 6,773,320	$ 144,580,144
6	Other Operating Revenue	$ 1,481,322	$ -	$ 1,481,322	$ -	$ 1,481,322
7	**Total Revenues**	$ 137,611,450	$ 1,676,696	$ 139,288,146	$ 6,773,320	$ 146,061,466
	EXPENSES:					
8	Operations - Production, Fuel	$ 59,803,425	$ (788,697)	$ 59,014,728	$ -	$ 59,014,728
9	Operations - Production, Steam	$ 8,764,555	$ -	$ 8,764,555	$ -	$ 8,764,555
10	Operations - Production, Other	$ 1,335,333	$ 407,983	$ 1,743,316	$ -	$ 1,743,316
11	Operations - Other Pwr Supply, Demand	$ 5,769,587	$ -	$ 5,769,587	$ -	$ 5,769,587
12	Operations - Other Pwr Supply - Energy	$ 12,420,888	$ (250,000)	$ 12,170,888	$ -	$ 12,170,888
13	Operations - Transmission	$ 8,036,486	$ -	$ 8,036,486	$ -	$ 8,036,486
14	Operations - Administrative and General	$ 9,191,902	$ 333,857	$ 9,525,759	$ -	$ 9,525,759
15	Maintenance - Production, Steam	$ 10,170,045	$ (657,788)	$ 9,512,257	$ -	$ 9,512,257
16	Maintenance - Production, Other	$ 2,809,881	$ -	$ 2,809,881	$ -	$ 2,809,881
17	Maintenance - Transmission	$ 28,388	$ (19,560)	$ 8,828	$ -	$ 8,828
18	Maintenance - General Plant	$ 63,958	$ -	$ 63,958	$ -	$ 63,958
19	Depreciation and Amortization	$ 7,608,735	$ (69,446)	$ 7,539,289	$ -	$ 7,539,289
20	ACC Gross Revenue Taxes	$ 288,752	$ (288,752)	$ -	$ -	$ -
21	Taxes	$ 3,346,839	$ -	$ 3,346,839	$ -	$ 3,346,839
22	**Total Operating Expenses**	$ 129,638,774	$ (1,332,402)	$ 128,306,372	$ -	$ 128,306,372
23	**Operating Margin Before Interest on L.T.- Debt**	$ 7,972,676	$ 3,009,098	$ 10,981,774	$ -	$ 17,755,094
24	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
25	Interest on Long-term Debt	$ 13,547,749	$ (234,585)	$ 13,313,164	$ -	$ 13,313,164
26	Other Interest & Other Dedcutions	$ 914,988	$ (572,598)	$ 342,390	$ -	$ 342,390
27	**Total Interest & Other Deductions**	$ 14,462,737	$ (807,183)	$ 13,655,554	$ -	$ 13,655,554
28	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (6,490,061)	$ 3,816,281	$ (2,673,780)	$ -	$ 4,099,540
29	***NON-OPERATING MARGINS***					
30	Interest Income	$ 582,014	$ -	$ 582,014	$ -	$ 582,014
31	Other Non-operating Income	$ 1,380,437	$ -	$ 1,380,437	$ -	$ 1,380,437
32	**Total Non-Operating Margins**	$ 1,962,451	$ -	$ 1,962,451	$ -	$ 1,962,451
33	***EXTRAORDINARY ITEMS***	$ -	$ -	$ -	$ -	$ -
34	***NET MARGINS (LOSS)***	$ (4,527,610)	$ 3,816,281	$ (711,329)	$ -	$ 6,061,991

35 References:
36 Column (A): Cooperative Schedule C-1, Pages 1 and 2
37 Column (B): Schedule CSB-12
38 Column (C): Column (A) + Column (B)
39 Column (D): Schedules CSB-1
40 Column (E): Column (C) + Column (D)

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1 Post-Test Year Revenues and Expenses Ref: Sch CSB-13	[C] ADJ #2 Revenue and Expense Annualizations Ref: Sch CSB-14	[D] ADJ #3 Asset Retirement Obligation Ref: Sch CSB-15	[E] ADJ #4 Tracker Mechanism (Base Power Cost) Ref: Sch CSB-16	[F] ADJ #5 Overhaul Accrual Expense Ref: Sch CSB-17	[G] ADJ #6 Transmission Expense Annualization for Contracts Ref: Sch CSB-18	[H] ADJ #7 Normalized Legal Expense Ref: Sch CSB-19
	REVENUES:								
1	Class A Members, Non-Base Cost of Power Revenue	$ 44,409,469	$ -	$ 1,271,908	$ -	$ (7,716,227)	$ -	$ -	$ -
2	Class A Members, Base Cost of Power Revenue	$ 41,276,155	$ -	$ -	$ -	$ 7,716,227	$ -	$ -	$ -
3	Total Class A Member Electric Revenue	$ 85,685,624	$ -	$ 1,271,908	$ -	$ -	$ -	$ -	$ -
4	Non-Class A, Non-Firm, & Non-Member	50,444,504	551,934	-	-	-	-	-	-
5	Total Electric Revenue	$ 136,130,128	$ 551,934	$ 1,271,908	$ -	$ -	$ -	$ -	$ -
6	Other Operating Revenue	$ 1,481,322	-	-	-	-	-	-	-
7	**Total Revenues**	$ 137,611,450	$ 551,934	$ 1,271,908	$ -	$ -	$ -	$ -	$ -
8	***OPERATING EXPENSES:***								
9	Operations - Production, Fuel	$ 59,803,425	$ -	$ 264,376	$ -	$ -	$ -	$ -	$ -
10	Operations - Production, Steam	8,764,555 [1]	-	-	-	-	-	-	-
11	Operations - Production, Other	1,335,333 [2]	407,983		-	-	-	-	-
12	Operations - Other Pwr Supply, Demand	5,769,587	-	-	-	-	-	-	-
13	Operations - Other Pwr Supply - Energy	12,420,888 [3]	-	-	-	(250,000)	-	-	-
14	Operations - Transmission	8,036,486	-	-	-	-	-	-	-
15	Operations - Administrative and General	9,191,902	-	-	-	-	-	-	539,989
16	Maintenance - Production, Steam	10,170,045 [4]	-	-	-	-	(657,788)	-	-
17	Maintenance - Production, Other	2,809,881	-	-	-	-	-	-	-
18	Maintenance - Transmission	28,388	-	-	-	-	-	(19,560)	-
19	Maintenance - General Plant	63,958	-	-	-	-	-	-	-
20	Depreciation and Amortization	7,608,735	-	-	(69,446)	-	-	-	-
21	ACC Gross Revenue Taxes	288,752	-	-	-	-	-	-	-
22	Taxes	3,346,839	-	-	-	-	-	-	-
23	**Total Operating Expenses**	$ 129,638,774	$ 407,983	$ 264,376	$ (69,446)	$ (250,000)	$ (657,788)	$ (19,560)	$ 539,989
24	**Operating Margin Before Interest on L.T.- Debt**	**$ 7,972,676**	$ 143,951	$ 1,007,531	$ 69,446	$ 250,000	$ 657,788	$ 19,560	$ (539,989)
25	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***								
26	Interest on Long-term Debt	$ 13,547,749	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Other Interest & Other Dedcutions	914,988	-	-	(572,598)	-	-	-	-
28	**Total Interest & Other Deductions**	$ 14,462,737	$ -	$ -	$ (572,598)	$ -	$ -	$ -	$ -
29	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (6,490,061)	$ 143,951	$ 1,007,531	$ 642,044	$ 250,000	$ 657,788	$ 19,560	$ (539,989)
30	***NON-OPERATING MARGINS***								
31	Interest Income	$ 582,014	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Other Non-operating Income	1,380,437	-	-	-	-	-	-	-
33	**Total Non-Operating Margins**	$ 1,962,451	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	***EXTRAORDINARY ITEMS***	$ -	-	-	-	-	-	-	-
35	***NET MARGINS (LOSS)***	$ (4,527,610)	$ 143,951	$ 1,007,531	$ 642,044	$ 250,000	$ 657,788	$ 19,560	$ (539,989)

Footnote Explanations

[1] Includes account nos. 500, 502 to 509
[2] Includes account nos. 546, 548 to 550
[3] Includes account nos. 555 to 557
[4] Includes account nos. 510 to 515

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LINE NO.	DESCRIPTION	[I] ADJ #8 Fuel Expense Ref: Sch CSB-20	[J] ADJ #9 Advertising Expense Ref: Sch CSB-21	[K] ADJ #10 Contributions & Other Expenses Ref: Sch CSB-22	[L] ADJ #11 ACC Gross Rev Assessment Ref: Sch CSB-23	[M] ADJ #12 Interest on Long Term Debt Ref: Sch CSB-24	[N] STAFF ADJUSTED
	REVENUES:						
1	Class A Members, Non-Base Cost of Power Revenue	$ -	$ -	$ -	$ (147,146)	$ -	$ 37,818,004
2	Class A Members, Base Cost of Power Revenue	$ -	$ -	$ -	$ -	$ -	$ 48,992,382
3	Total Class A Member Electric Revenue	$ -	$ -	$ -	$ (147,146)	$ -	$ 86,810,386
4	Non-Class A, Non-Firm, & Non-Member	-	-	-	-	-	50,996,438
5	Total Electric Revenue	$ -	$ -	$ -	$ (147,146)	$ -	137,806,824
6	Other Operating Revenue	-	-	-	-	-	1,481,322
7	**Total Revenues**	$ -	$ -	$ -	$ (147,146)	$ -	$ 139,288,146
8	***OPERATING EXPENSES:***						
9	Operations - Production, Fuel	$ (1,053,073)	$ -	$ -	$ -	$ -	$ 59,014,728
10	Operations - Production, Steam	-	-	-	-	-	8,764,555
11	Operations - Production, Other	-	-	-	-	-	1,743,316
12	Operations - Other Pwr Supply, Demand	-	-	-	-	-	5,769,587
13	Operations - Other Pwr Supply - Energy	-	-	-	-	-	12,170,888
14	Operations - Transmission	-	-	-	-	-	8,036,486
15	Operations - Administrative and General	-	(46,241)	(159,891)	-	-	9,525,759
16	Maintenance - Production, Steam	-	-	-	-	-	9,512,257
17	Maintenance - Production, Other	-	-	-	-	-	2,809,881
18	Maintenance - Transmission	-	-	-	-	-	8,828
19	Maintenance - General Plant	-	-	-	-	-	63,958
20	Depreciation and Amortization	-	-	-	-	-	7,539,289
21	ACC Gross Revenue Taxes	-	-	-	(288,752)	-	-
22	Taxes	-	-	-	-	-	3,346,839
23	**Total Operating Expenses**	$ (1,053,073)	$ (46,241)	$ (159,891)	$ (288,752)	$ -	$ 128,306,372
24	**Operating Margin Before Interest on L.T.- Debt**	$ 1,053,073	$ 46,241	$ 159,891	$ 141,606	$ -	**$ 10,981,774**
25	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***						
26	Interest on Long-term Debt	$ -	$ -	$ -	$ -	$ (234,585)	$ 13,313,164
27	Other Interest & Other Dedcutions	-	-	-	-	-	342,390
28	**Total Interest & Other Deductions**	$ -	$ -	$ -	$ -	$ (234,585)	$ 13,655,554
29	***MARGINS (LOSS) AFTER INTERST EXPENSE***	$ 1,053,073	$ 46,241	$ 159,891	$ 141,606	$ 234,585	$ (2,673,780)
30	***NON-OPERATING MARGINS***						
31	Interest Income	$ -	$ -	$ -	$ -	$ -	$ 582,014
32	Other Nonoperating Income	-	-	-	-	-	1,380,437
33	**Total Non-Operating Margins**	$ -	$ -	$ -	$ -	$ -	$ 1,962,451
34	***EXTRAORDINARY ITEMS***	-	-	-	-	-	-
35	***NET MARGINS (LOSS)***	$ 1,053,073	$ 46,241	$ 159,891	$ 141,606	$ 234,585	$ (711,329)

Arizona Electric Power Cooperative, Inc. Schedule CSB-13
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

OPERATING INCOME ADJUSTMENT NO. 1 - POST-TEST YEAR REVENUE AND EXPENSE FOR COAL BLENDING PLANT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	**Revenues**			
2	AEPCO Adjustment No. 5 - Fuel Expense	$ (551,934)	$ 551,934	$ -
3	**Total Revenues**	$ (551,934)	**$ 551,934**	$ -
4	**Expenses**			
5	AEPCO Adjustment No. 5 - Fuel Expense	$ (1,534,274)	$ 1,534,274	$ -
6	AEPCO Adjustment No. 6 - S02 Allowance	$ (167,069)	$ 167,069	$ -
7	AEPCO Adjustment No. 7 - Ash Credit Sales	$ 820,611	$ (820,611)	$ -
8	AEPCO Adjustment No. 8 - Depr and Prop Tax	$ 472,749	$ (472,749)	$ -
9	**Total Operating Expenses**	$ (407,983)	**$ 407,983**	$ -
10	**Operating Margin Before Interest on L.T. Debt**	$ (143,951)	**$ 143,951**	$ -
11	AEPCO Adjustment No. 8 - Interest on L.T.-Debt (see Note)	$ 532,465	$ -	$ 532,465
12	**Operating Margin After Interest on L.T. Debt**	**$ (676,416)**	**$ 143,951**	**$ (532,465)**

13 Note: The $532,465 is included in the Cooperative filed amount for Interest on L.T. Debt.

14 References:

15 Column A: Cooperative Schedule C-2, Pages 5 and 6
16 Column B: Testimony, CSB
17 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-14

OPERATING INCOME ADJUSTMENT NO. 2 - REVENUE AND EXPENSE ANNUALIZATIONS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Class A Member Demand Revenues	$ 36,990,731	$ -	$ 36,990,731
2	Class A Member Energy Revenues	$ 40,285,075	$ -	$ 40,285,075
3	Class A Member ACC Assessment Rev	$ 147,146	$ (147,146)	$ -
4	Class A Member Fixed Charge Revenues	$ 8,262,672	$ (8,262,672)	$ -
5	Total Class A Member Base Rate Revenues	$ 85,685,624	$ (8,409,818)	$ 77,275,806
6	Factor to Annualize Revenues to End of Test Year	0.00%		1.65%
7	**Revenue Annualization Adjustment**	$ -	**$ 1,271,908**	$ 1,271,908
8	Variable Expenses Not Recovered Through Fuel Adj	$ -		$ 16,062,410
9	Factor to Annualize Revenues to End of Test Year	0.00%		1.65%
10	**Adjustment to Expenses**	$ -	**$ 264,376**	$ 264,376

		Calculation of Annualization Factor						
11								
12		Number of Customers						
13		Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
14	2002	3,702	2,446	7,481	31,701	43,113	27,631	116,074
15	2003	3,824	2,484	7,623	32,804	44,431	28,729	119,895
16	Increase	122	38	142	1,103	1,318	1,098	3,821
17	% Increase	3.30%	1.55%	1.90%	3.48%	3.06%	3.97%	3.29%
18	2003 Growth Rate							3.29%
19	Annualization Factor - 2003 Growth Rate divided by 2							1.6459%

	Caculation of Variable Expenses Not Recovered Through Fuel Adjustor			
20–23	Account No.	Description	Amount	
24	500	Operation Supervision and Engineering	$ 1,999,908	
25	501&547	Fuel - Steam Power & Other	$ 59,803,425	
26	502	Steam Expenses	$ 2,710,803	
27	505	Electric Expenses	$ 1,437,524	
28	510	Maintenance Supervision & Engineering	$ 840,774	
29	512	Maintenance of Boiler Plant	$ 6,433,681	
30	513	Maintenance of Electric Plant	$ 264,759	
31	514	Maintenance of Miscellaneous Steam Plant	$ 2,374,961	
32	555	Purchased Power - Demand	$ 5,769,587	
33	555	Purchased Power - Energy	$ 10,085,538	
34		Total Variable Expenses	$ 91,720,960	
35	501&547	Fuel - Steam Power & Other	$ (59,803,425)	Recovered through Fuel Adj
36	555	Purchased Power - Demand	$ (5,769,587)	Recovered through Fuel Adj
37	555	Purchased Power - Energy	$ (10,085,538)	Recovered through Fuel Adj
38			$ 16,062,410	
39		2003 Growth Rate	1.65%	
40		Adjustment to Expenses	$ 264,376	

41 References:
42 Column A: Cooperative Data Request Response CSB 6-1
43 Column B: Testimony, CSB
44 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-15

OPERATING INCOME ADJUSTMENT NO. 3 - ASSET RETIREMENT OBLIGATION

		Effects on Net Margin				
		[A]	[B]	[C]	[D]	[E]
LINE NO.	DESCRIPTION	AEPCO ACTUAL TEST YEAR Sch C-1, Page 1	AEPCO ADJUSTMENTS TO ACTUAL Sch C-1, Page 4	AEPCO ADJUSTED TEST YEAR Sch C-1, Page 4	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Revenue	$ -	$ -	$ -	$ -	$ -
2	Expense - Depreciation	$ 69,446	$ -	$ 69,446	$ (69,446)	$ -
3	Operating Margin Before Interest	$ (69,446)	$ -	$ (69,446)	**$ 69,446**	$ -
4	Interest and Other Deductions, ARO	$ -	$ 381,034	$ 381,034	$ (381,034)	$ -
5	Interest and Other Deductions, Accretion	$ 191,564	$ -	$ 191,564	$ (191,564)	$ -
6	Total Interest	$ 191,564	$ 381,034	$ 572,598	**$ (572,598)**	$ -
7	Extraordinary Items	$ 3,810,335	$ (3,810,335)	$ -	$ -	$ -
8	Net Margin	$ (4,071,345)	$ 3,429,301	$ (642,044)	**$ 642,044**	$ -

9 References:

10 Column A: Cooperative Data Request Response CSB 1-1 and CSB 1-2; Note 19 of 2003 Audited Financial Statements

11 Column B: Direct Testimony; Cooperative Witness, Gary Pierson

12 Column C: Column [A] + Column [B]

13 Column D: Testimony, CSB

14 Column E: Column [C] + Column [D]

Arizona Electric Power Cooperative, Inc. Schedule CSB-16
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

OPERATING INCOME ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	**Base Cost of Power Revenue**			
2	Test Year Sales (In kWhs)	2,025,326,533	-	2,025,326,533
3	Base Cost of Power (Col A, per Dec 58405)	$ 0.017140	$ 0.003240	$ 0.020380
4	**Adjustment to match Coop proposed power expense to revenue**	$ 34,714,097	**$ 6,562,058**	$ 41,276,155
5	Test Year Sales (In kWhs)	2,025,326,533		2,025,326,533
6	Base Cost of Power (Col C, Line 53/Line 5)	$ 0.020380	$ (0.003810)	$ 0.016570
7	**Adjustment to reflect Staff's adjustments to power costs**	$ 41,276,627	**$ (7,716,227)**	$ 33,560,400
8	**Total**	$ 34,714,097	**$ (1,153,697)**	$ 33,560,400
9	**Base Cost of Power Expense**			
10	Coal Fired Steam Plant Costs:			
11	Fuel, Coal ($1,534,274 Coop Adj No. 5 - $1,030,873 legal exp)	$ 42,029,531	$ 503,401	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-
14	**Less:** Fixed Fuel Costs	(549,137)	253,272	(295,865)
15	Subtotal	$ 43,789,748	$ 756,673	$ 44,546,421
16	Internal Combustion Plant Costs:			
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809
19	Less: Fixed Fuel Costs	(1,435,208)	1,435,208	-
20	Subtotal	$ 14,029,332	$ 1,435,208	$ 15,464,540
21	**Total Fuel Costs**	**$ 57,819,080**	**$ 2,191,881**	**$ 60,010,961**
22	Purchased Power Energy Costs			
23	Firm Purchases			
24	CRSP	$ 309,547	$ -	$ 309,547
25	Pacificorp	-	-	-
26	Parker Davis	217,629	-	217,629
27	Public Service Company of New Mexico	1,963,061	(250,000)	1,713,061
28	Panda Gila River	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-
30	Subtotal Firm Purchases	$ 3,624,810	$ (250,000)	$ 3,374,810
31	Nonfirm Purchases, Demand	$ -	5,769,587	$ 5,769,587
32	Nonfirm Purchases, Energy	6,460,728	-	6,460,728
33	**Total Purchased Energy Costs**	**$ 10,085,538**	**$ 5,519,587**	**$ 15,605,125**
34	**Firm Wheeling Expenses**	$ -	7,939,635	$ 7,939,635
35	**Non-firm Wheeling Expenses**	77,291	-	77,291
36	**Total Firm and Non-Firm Wheeling Expenses**	**$ 77,291**	**$ 7,939,635**	**$ 8,016,926**
37	**TOTAL FUEL COSTS & PURCHASED ENERGY**	**$ 67,981,909**	**$ 15,651,103**	**$ 83,633,012**
38	**Less:**			
39	Non-tariff Sales Fuel Recovery			
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-
42	City of Mesa (PSA)	2,657,351	(90,879)	2,566,472
43	ED-2 Power Supply	1,376,189	(20,185)	1,356,004
44	SRP	13,039,105	(260,828)	12,778,277
45	Safford	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921
47	Subtotal	$ 18,311,016	$ (371,892)	$ 17,939,124
48	Other Sales Fuel Recovery:			
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,705,282	$ (371,892)	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ -	$ 23,739,222	$ 23,739,222
52	**Total Non-Tariff Sales Fuel Recovery, Energy and Demand**	**$ 26,705,282**	**$ 23,367,330**	**$ 50,072,612**
53	**Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)**	**$ 41,276,627**	**$ (7,716,227)**	**$ 33,560,400**

54 References:
55 Column A: Decision No. 58405, page 29, line 25; Cooperative Application Schedule H-2A
56 Column B: Testimony, CSB
57 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc. Schedule CSB-17
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OPERATING INCOME ADJUSTMENT NO. 5 - OVERHAUL ACCRUAL EXPENSE

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Overhaul Accrual Expense	$4,787,508	**$ (657,788)**	$ 4,129,720

		ST1	ST2	ST3	GT1	GT2*	GT3	GT4**	Total
2		**ST1**	**ST2**	**ST3**	**GT1**	**GT2***	**GT3**	**GT4****	**Total**
3	1996	$ -	$ -	$ 5,180,041	$ -	$ -	$ -	$ -	$ 5,180,041
4	1997	$ -	$ 2,671,333	$ 489,239	$ -	$ -	$ -	$ -	$ 3,160,572
5	1998	$ -	$ -	$ 1,775,453	$ -	$ -	$ -	$ -	$ 1,775,453
6	1999	$ -	$ 3,828,921	$ -	$ -	$ -	$ 2,347,954	$ -	$ 6,176,875
7	2000	$ 94,116	$ 381,564	$ 1,181,848	$ -	$ -	$ -	$ -	$ 1,657,528
8	2001	$ 3,100,357	$ 2,740,233	$ -	$ 3,172,225	$ -	$ -	$ -	$ 9,012,815
9	2002	$ -	$ -	$ 2,868,220	$ -	$ -	$ -	$ -	$ 2,868,220
10	2003	$ -	$ 3,148,905	$ -	$ -	$ -	$ -	$ 57,354	$ 3,206,259
11		$ 3,194,473	$ 12,770,956	$ 11,494,801	$ 3,172,225	$ -	$ 2,347,954	$ 57,354	$ 33,037,763
12								Divided by	8
13									$ 4,129,720

14 * Per response to CSB 1-38, there has been no actual overhaul expense
15 for generating GT2 for the period 1990 to 2004.

16 ** Per response to CSB 1-37, unit GT4 was placed in service in 2002.

17 <u>References:</u>

18 Column A: Cooperative Data Request Response CSB 1-37 and 1-38
19 Column B: Testimony, CSB
20 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-18

OPERATING INCOME ADJUSTMENT NO. 6 - TRANSMISSION EXPENSE ANNUALIZATION FOR CONTRACTS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Contract Billing Units (in kW's)	1,956,000	-	1,956,000
2	Transmission rate per kW (see note below)	$ 3.032	$ (0.010)	$ 3.022
3	AEPCO Firm Transmission Expense	$ 5,930,592	**$ (19,560)**	$ 5,911,032

		Contract Billing Units (in kW's)		
4				
5		Per Cooperative	Adjustments	Per Staff
6	SRP	1,200,000	-	1,200,000
7	City of Mesa	180,000	-	180,000
8	Electric District 2	96,000	-	96,000
9	Apache Mead	480,000	-	480,000
10	Total	1,956,000	-	1,956,000

11 Note
12 The transmission rate is the Southwest Transmission proposed rate.

13 References:

14 Column A: Cooperative work paper "Computation of Adjustment to Annualize Wheeling Contracts"
15 Column B: Testimony, CSB
16 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-19

OPERATING INCOME ADJUSTMENT NO. 7 - NORMALIZED LEGAL EXPENSE

LINE NO.	DESCRIPTION		Normalized Legal Expense Calculation
1	**2003 Legal Expenses excl Rail Transportation Tariff Exp - Per Coop (Data Requ Response CSB 13-5)**	**$**	**903,512**
2	Transferred Rail Trans Tariff legal exp from Fuel Exp (from Operating Income Adj No. 8, Sch CSB-20)	$	1,030,873
3	Subtotal	$	1,934,385
4	Additional Expenses from 2003 Legal Exp Report; Data Requ Resp CSB 1-33 (Line 5-Line1-Line2)	$	761,373
5	Total Legal Expenses Per Cooperative's 2003 Legal Expense Report	$	2,695,758
6	To reflect Staff's normalized Rail Transportation Tariff Exp from Sch CSB-7.1 ($1,792,246-$620,129)	$	(1,172,117)
7	Subtotal	$	1,523,641
8	To reflect Staff's normalized Legal Expense Excluding Rail Transp Tariff Exp from Sch CSB-19.2	$	(80,140)
9	**Normalized Legal Expense - Per Staff**	**$**	**1,443,501**
10	Legal Expense - Per Cooperative (Line 1)	$	903,512
11	**Staff's Adjustment (Line 9 - Line 10)**		**539,989**

12 References:
13 Data Request Responses CSB 13-5 and CSB 1-33; Schedules CSB-19.1 and CSB-19.2

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-19.1

NORMALIZED RAILROAD LEGAL EXPENSES

LINE NO.	DESCRIPTION		NORMALIZED RAILROAD TRANSPORTATION TARIFF LEGAL EXPENSE
1	2002 Railroad Transportation Tariff Legal Expenses	$	209,924
2	2003 Railroad Transportation Tariff Legal Expenses		1,792,246
3	2004 Railroad Transportation Tariff Legal Expenses		1,098,477
4	Total Railroad Transportation Tariff Legal Expenses	$	3,100,647
5	Divided by 5 years (Contract Term)		5
6	Normalized Railroad Transportaion Legal Expense - Per Staff	$	620,129
7	2003 Railroad Transportation Tariff Legal Expenses - Per Coop		1,792,246
8	**Staff's Adjustment**	**$**	**(1,172,117)**

9 References:

10 Cooperative Data Request Response CSB 1-33, CSB 13-1, CSB 14-1, CSB 14-2, and Testimony, CSB

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-19.2

NORMALIZED LEGAL EXPENSE
Excluding Railroad Transportation Tariff Legal Expense

LINE NO.	DESCRIPTION		Normalized Legal Expense Calculation (Excl Rail Transp)
1	**2003 Legal Expenses excl Rail Transportation Tariff Expense - Per Cooperative (CSB 13-5)**	**$**	**903,512**
2	To properly reflect AEPCO's allocation for natural gas related legal expenses [$354,824 x (1-0.8023)]	$	(70,149)
3	To properly reflect legal expenses re: El Paso Electric contract that will be effective 2005-2008	$	(23,182)
4	To properly remove PUHCA related legal expenses (CSB 15-5 b)	$	(15,500)
5	To remove capitalized legal exp (CSB 1-33 & 13-5; Office Prop, Coal Blending Plant)	$	(13,605)
6	To remove costs related to redacted legal invoices	$	(68,412)
7	**Adjusted 2003 Legal Expenses**	**$**	**712,664**
8	**2002 Total Legal Expenses - Per Cooperative**	**$**	**1,101,927**
9	To properly reflect AEPCO's allocation for natural gas related legal expenses [$220,906 x (1-0.8023)]	$	(43,673)
10	To remove Restructuring legal costs	$	(48,834)
11	To remove Rail Transportation Tariff legal costs	$	(209,924)
12	**Adjusted 2002 Legal Expenses**	**$**	**799,496**
13	**2004 Total Legal Expenses - Per Cooperative**	**$**	**2,112,189**
14	To properly reflect AEPCO's allocation for natural gas related legal expenses [$282,030 x (1-0.8023)]	$	(55,757)
15	To remove Rail Transportation Tariff legal costs	$	(1,098,477)
16	**Adjusted 2004 Legal Expenses**	**$**	**957,955**
17	**Total Adjusted 2002, 2003 and 2004 Legal Expenses (Line 7 + Line 12 + Line 16)**	**$**	**2,470,115**
18	**Normalized Legal Expense (Line 17 divided by 3) - Per Staff**	**$**	**823,372**
19	Legal Expense - Per Cooperative (Line 1)	$	903,512
20	**Staff's Adjustment (Line 18 - Line 19)**		**(80,140)**
21	References:		
22	Data Request Responses CSB 13-5 and CSB 1-33; Schedules CSB-19.1 and CSB-19.2		

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-20

OPERATING INCOME ADJUSTMENT NO. 8 - FUEL EXPENSE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
	Summary of Variable Coal Fuel Costs			
1	Before the Burn	$ 64,024,628.18	$ -	$ 64,024,628.18
2	Purchase Dollars	$ 17,677,372.66	$ -	$ 17,677,372.66
2	Sales Tax	$ 1,098,611.58	$ -	$ 1,098,611.58
4	Quality	$ 248,731.33	$ -	$ 248,731.33
5	Transportation	$ 11,995,936.28	$ -	$ 11,995,936.28
6	Est. 151 Accrual	$ -	$ -	$ -
7	Subtotal	$ 95,045,280.03	$ -	$ 95,045,280.03
8	Rail Invoices/Demurrge	$ 634,323.21	$ -	$ 634,323.21
9	**Rail Invoices/Demurrge (Legal)**	**$ 2,346,719.65**	$ (2,346,719.65)	**$ -**
10	Subtotal	$ 2,981,042.86	$ (2,346,719.65)	$ 634,323.21
11	Total $ Available Before the Burn (Line 7 + Line 10)	$ 98,026,322.89	$ (2,346,719.65)	$ 95,679,603.24
12	Tons Before Burn	3,425,374.41	-	3,425,374.41
13	Variable Weighted Average (Line 11 / Line 12)	$ 28.62	$ (0.69)	$ 27.93
14	Steam 2 Tons Burned	719,472.15	-	719,472.15
15	**Steam 2 Dollars Burned (Line 13 x Line 14)**	**$ 20,589,635.13**	$ (492,909.45)	**$ 20,096,725.68**
16	Adjustment to reconcile to actual Steam 2 Dollars Burned	$ (213,586.55)	$ 1,369.95	$ (212,216.60)
17	**Actual Steam 2 Dollars Burned**	**$ 20,376,048.58**	$ (491,539.50)	**$ 19,884,509.08**
18	Steam 3 Tons Burned	786,745.15	-	786,745.15
19	**Steam 3 Dollars Burned (Line 13 x Line 18)**	**$ 22,514,833.38**	$ (538,998.10)	**$ 21,975,835.28**
20	Adjustment to reconcile to actual Steam 3 Dollars Burned	$ (152,978.79)	$ (335.59)	$ (153,314.38)
21	**Actual Steam 3 Dollars Burned**	**$ 22,361,854.59**	$ (539,333.69)	**$ 21,822,520.90**
22	**Total Steam Dollars Burned (Line 17 + Line21)**	**$ 42,737,903.17**	**$ (1,030,873.19)**	**$ 41,707,029.98**
23	**Procurement Costs**	**$ 1,487,755.23**	**$ -**	**$ 1,487,755.23**
24	**Fixed Costs - Interest on L.T. Debt (CSB 3-14)**	**$ 295,864.69**	**$ (22,199.90)**	**$ 273,664.79**
25	**Total Coal Fuel Costs**	**$ 44,521,523.09**	**$ (1,053,073.09)**	**$ 43,468,450.00**

Reference: Data Request Response CSB 3-14

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
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Schedule CSB-21

OPERATING INCOME ADJUSTMENT NO. 9 - ADVERTISING EXPENSE

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Advertising Expense	$ 46,241	**$ (46,241)**	$ -

2 References:

3 Column A: Cooperative Data Request Response CSB 1-35
4 Column B: Testimony, CSB
5 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-22

OPERATING INCOME ADJUSTMENT NO. 10 - CHARITABLE CONTRIBUTIONS & OTHER EXPENSES

LINE NO.	DATA REQUEST RESPONSE	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	CSB 1-41	AEPCO Sponsorships	$ 56,296	$ (56,296)	$ -
2	CSB 1-41	AEPCO Food, Luncheons, Dinners	$ 12,706	$ (12,706)	$ -
3	CSB 1-41	AEPCO - Meals & Entertainment	$ 12,470	$ (12,470)	$ -
4	CSB 3-22	Billings from Affiliates - Charitable Contributions	$ 16,108	$ (16,108)	$ -
5	CSB 3-22	Billings from Affiliates - Sponsorships	$ 1,074	$ (1,074)	$ -
6	CSB 3-22	Billings from Affiliates - Food	$ 15,663	$ (15,663)	$ -
7	CSB 3-22	Billings from Affiliates - Awards	$ 468	$ (468)	$ -
8	CSB 3-22	Billings from Affiliates - Party	$ 5,250	$ (5,250)	$ -
9	CSB 3-22	Billings from Affiliates - Meals & Entertainment	$ 11,769	$ (11,769)	$ -
10	CSB 6-4	Lobbying Costs Included in Memberships	$ 28,087	$ (28,087)	$ -
11		TOTAL	$ 159,891	**$ (159,891)**	$ -

12 References:

13 Column A: Cooperative Data Request Response CSB 1-41, 3-22, and 6-4
14 Column B: Testimony, CSB
15 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-23

OPERATING INCOME ADJUSTMENT NO. 11 - ACC GROSS REVENUE ASSESSMENT

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Revenue - ACC Assessment	$ 147,146	**$ (147,146)**	$ -
2	Expense - ACC Assessment	$ 288,752	**$ (288,752)**	$ -
3	Operating Margin Before Interest	$ (141,606)	**$ 141,606**	$ -

4 References:

5 Column A: Cooperative Schedule C-1, Page 4, Line 41
6 Column B: Testimony, CSB
7 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-24

OPERATING INCOME ADJUSTMENT NO. 12 - INTEREST EXP ON LONG-TERM DEBT

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Interest Expense on L.T.- Debt	$ 13,547,749	$ (234,585)	$ 13,313,164

2 References:

3 Column A: Cooperative Schedule C-1
4 Column B: Testimony, CSB
5 Column C: Column [A] + Column [B]

RAMIREZ

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN)	DOCKET NO. E-01773A-04-0528

DIRECT

TESTIMONY

OF

ALEJANDRO RAMIREZ

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2004

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ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0528

The direct testimony of Staff witness Alejandro Ramirez addresses the following issues:

Operating Income, TIER and DSC Ratios – Staff recommends operating revenues no less than the $146,061,494 proposed by Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Applicant"). AEPCO's proposed revenues would provide a times interest earned ratio ("TIER") of 1.33 and a debt service coverage ("DSC") ratio of 0.91. The Applicant's proposed revenue fails to provide sufficient internally generated cash flow, directly or indirectly through incremental debt financing, for plant replacement, improvement and expansion requirements.

Capital Structure – The Applicant's actual end of test year capital structure was composed by 95.2 percent debt and 4.8 percent patronage equity. This is an excessively leveraged capital structure. This rate case is the appropriate time to address AEPCO's highly leveraged capital structure. The capital structure issue is important because a highly leveraged capital structure has potentially detrimental impacts for service reliability and rates. The Applicant has not demonstrated that its proposed revenue is consistent with the Commission's order (Decision No. 64227, dated November 29, 2001) to establish long-range goals to improve its patronage equity position. Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff further recommends that the Commission restrict the distribution of future patronage dividends by AEPCO until it has achieved a capital structure composed of at least 30 percent patronage equity.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my position as a Public Utilities Analyst, I perform studies to estimate the cost of capital component of the revenue requirement in rate proceedings. I also perform other financial analyses.

Q. Please describe your educational background and professional experience.

A. In 2002, I graduated summa cum laude from Arizona State University, receiving a Bachelor of Science degree in Global Business with a specialization in finance. While attending Arizona State University, I successfully completed the Barrett Honors College curriculum. My course of studies included classes in corporate and international finance, investments, accounting, statistics, and economics. I began employment as a Staff Public Utilities Analyst in 2003. Since that time, I have provided recommendations to the Commission on financings and prepared various studies in the field of cost of capital and econometrics. I have also attended seminars related to general regulatory and business issues.

Q. What is the scope of your testimony in this case?

A. I discuss Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Applicant") current capital structure and provide Staff's recommended operating income. I also provide the times interest earned ("TIER") and debt service coverage ("DSC") ratios resulting from Staff's recommended operating income.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. This testimony is organized in three sections. Section I presents the Applicant's long-term debt and patronage equity balances. Section II discusses AEPCO's capital structure. Finally, Section III discusses Staff's recommended TIER and DSC ratios for the Applicant.

Q. Have you prepared any exhibits to your testimony?

A. Yes. I prepared three schedules (AXR-1 to AXR-3) that support Staff's recommendations.

Q. What is Staff's recommended operating income for the Applicant?

A. Staff recommends an operating income no less than $17,755,094 for AEPCO (which is the operating income that would result from the Applicant's proposed revenues).

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $17,755,094?

A. Operating income of $17,755,094 would produce a 1.33 TIER and a 0.91 DSC.

AEPCO'S LONG-TERM DEBT AND PATRONAGE AND EQUITY BALANCE

Q. What is the amount of AEPCO's long-term debt outstanding?

A. The Applicant had $218,909,935 in long-term debt outstanding as of November 1, 2004, and it is expected to incur $13,313,164 in interest expense related to its long-term debt during the year.

Q. What were AEPCO's patronage equity balances for the years ended 2003, 2002 and 2001?

A. AEPCO's patronage equity balances for the years ended 2003, 2002 and 2001 were $10,754,721, $17,803,568 and $13,904,998, respectively.

AEPCO'S CAPTIAL STRUCTURE

Q. What was AEPCO's actual end of test year capital structure?

A. The Applicant's actual end of test year capital structure was composed by 95.2 percent debt and 4.8 percent patronage equity[1]. Schedule AXR-1 presents the Applicant's capital structures for the years 2001, 2002 and 2003.

Q. Is AEPCO concerned with its current capital structure?

A. Yes. In his direct testimony, the Applicant's witness, Mr. William K. Edwards, has emphasized the importance for AEPCO to develop a stronger patronage equity base. Moreover, Mr. Edwards recognizes and supports the efforts made by both the Commission and AEPCO to establish long-term goals for AEPCO's patronage equity (Decision No. 64227, dated November 29, 2001, and Decision No. 65210, dated September 20, 2002).

[1] Staff has calculated the capital structure by taking into account long-term debt and equity.

Q. How does AEPCO's capital structure compare to other Generation and Transmission ("G&T") utilities' capital structure?

A. Mr. William Edwards has compared AEPCO's capital structure to the Capital structure of 55 G&T utilities' capital structure. As mentioned in his testimony, AEPCO's capital structure is more leveraged than Mr. Edwards' G&T utilities sample (See Mr. Edwards Direct Testimony, Page 8, Line 16-17). Schedule AXR-2 presents the capital structure of some G&T cooperatives that are rated by *Standard & Poor's* ("S&P") and the Applicant's capital structure for the test year ended December 2003. The average capital structure of the G&T cooperatives is composed of 81.0 percent debt and 19.0 percent patronage equity as opposed to the Applicant's capital structure composed of 95.2 percent debt and 4.8 percent patronage equity.

Q. Is Staff concerned with the Applicant's actual end of test year capital structure?

A. Yes. AEPCO's capital structure is highly leveraged as it has remained for several years. The Applicant's capital structure has multiple potential negative effects including: (1) higher debt costs for new issuances; (2) reduced ability to incur new debt and finance capital improvements; and (3) places upward pressure on rates to cover debt service obligations.

Q. Has the Commission shown concern with highly leveraged cooperatives?

A. Yes. In Decision No. 58405 (dated September 3, 1993), the Commission stated that "...there is a balance to be struck between keeping rates competitive and eliminating negative equity, but we fail to see any strong commitment or serious steps taken on AEPCO's part to build its equity (Page 23, lines 6-9)". In addition, the Commission ordered Arizona Electric Power Cooperative ("AEPCO") (Decision No. 64227, dated

November 29, 2001) and SWTCO (Decision No. 64991, dated June 26, 2002) to establish long-range goals to improve their patronage equity positions. In addition, the Commission ordered Trico Electric Cooperative, Inc. ("Trico") to file a capital improvement plan with the Commission (Decision No. 67412, dated November 2, 2004). As discussed previously, highly leveraged capital structures present potentially negative consequences.

Q. Does the Rural Utilities Service ("RUS") have any restrictions in regard to distribution of patronage dividends for highly leverage cooperatives?

A. Yes. AEPCO's audited financial statements for the years ended December 31, 2003 and 2002, state "RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative (See Exhibit GEP-1, note to financial statement 12)".

Q. Does the National Rural Utilities Cooperative Finance Corporation ("CFC") have any restrictions in regard to distribution of patronage dividends for highly leverage cooperatives?

A. Yes. The CFC requires a borrower to have a capital structure composed of at least 30 percent patronage equity to distribute 100 percent of its net earnings as patronage dividends. If the borrower has a capital structure composed of less than 30 percent patronage equity, it would be able to distribute as patronage dividends only 30 percent of its patronage capital or operating margins for the preceding year.

Q. What approach does Staff recommend to improve AEPCO's capital structure?

A. Staff recommends steadily growing the Applicant's patronage equity by setting rates that balance the interest of the ratepayers and AEPCO's long-term financial health. AEPCO has not shown how its proposed rates will improve its highly leveraged capital structure in a reasonable timeframe. Staff anticipates that the Applicant will use the opportunity provided by rebuttal testimony to explain how its proposed rate will adequately satisfy its capital structure deficiency.

OPERATING INCOME, TIER AND DCS RATIOS

Q. What do the times interest earned ("TIER") and the debt service coverage ("DSC") ratios represent?

A. TIER represents the number of times operating income covers interest expense on long-term debt. A TIER greater than 1.0 means that operating income is greater than interest expense.

DSC represents the number of times internally generated cash covers required principal and interest payments on long-term debt. A DSC greater than 1.0 indicates that operating cash flow is sufficient to cover debt obligations.

Q. Do the Applicant's lenders have debt covenants for TIER and DSC?

A. Yes. The Rural Utilities Service ("RUS") requires AEPCO to maintain a minimum TIER of 1.05 and a minimum DSC of 1.0 on an annual average best two of three year basis.

Q. What TIER and DSC level does the Applicant claim will result from its proposed revenues?

A. The Applicant claims its proposed revenues would result in a 1.29 TIER and a 1.05 DSC. AEPCO's witness, Mr. Edwards, states in his direct testimony that "...these are minimum ratios to provide some financial stability and allow for equity improvement (Mr. Edwards Direct Testimony, Page 11, Line 4 & 5)".

Q. What TIER and DSC level does Staff conclude would result from the Applicant's proposed revenues?

A. Staff has calculated that AEPCO's proposed revenues would result in a TIER of 1.33 which also equates to a 0.91 DSC. The Applicant's proposed revenues are not sufficient to service its debt obligations.

Q. Has the Applicant demonstrated that its proposed revenues are sufficient to improve its equity position in a reasonable timeframe?

A. No. The Applicant has provided no support to demonstrate that its proposed revenues are sufficient to provide patronage equity growth to achieve a capital structure of at least 30 percent patronage equity in a reasonable timeframe.

Q. What does Staff recommend in regard to AEPCO's revenues, TIER, and DSC?

A. Staff recommends no reduction to AEPCO's proposed operating revenue. Staff's analysis shows that the Applicant's proposed revenues are inadequate to cover its debt service obligations. The Applicant's current financial situation and proposed revenues would not support additional debt financing such as its November 4, 2004 request for authorization for debt financing (Docket No. E-01773A-04-0793).

CONCLUSION

Q. Please summarize Staff's recommendations.

A. Staff recommends that the Commission adopt operating revenues of no less than those proposed by the Applicant. The Applicant's proposed revenues fail to provide sufficient internally generated cash flow to finance, directly or indirectly through additional future debt financing, plant replacement, improvement and expansion requirements. The Applicant has not demonstrated that its proposed revenue is consistent with the Commission's order (Decision No. 64227, dated November 29, 2001) to establish long-range goals to improve its patronage equity position. Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff also recommends that the Commission restrict the distribution of future patronage dividends by AEPCO until it has achieved a capital structure composed of at least 30 percent patronage equity.

Q. Does this conclude your direct testimony?

A. Yes, it does.

AEPCO'S HISTORICAL CAPITAL STRUCTURE

Year	% Debt	% Patronage Equity
2001	93.6%	6.4%
2002	92.2%	7.8%
2003	95.2%	4.8%

Source: Based on the Applicant's filing

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528

SAMPLE ELECTRIC COOPERATIVES' CAPITAL STRUCTURE

G&T Coops	% Debt[1]	% Patronage Equity[1]
Associated Electric Coop., Inc.	78.0%	22.0%
Arkansas Electric Coop., Inc.	56.6%	43.4%
Old Dominion Electric Cooperative	77.9%	22.1%
Basin electric Power Cooperative	61.1%	38.9%
Central Iowa Power	78.4%	21.6%
Oglethorpe Power	89.2%	10.8%
Seminole Electric Cooperative	90.5%	9.5%
Tri-state Generating & Transmission Assoc.	85.2%	14.8%
Hoosier Energy Rural Electric Coop., Inc.	88.1%	11.9%
Chugach Electric Association	74.4%	25.6%
Alabama Electric Coop., Inc.	91.3%	8.7%
Western Farmer's electric	91.7%	8.3%
Great River Energy	90.8%	9.2%
Average	81.0%	19.0%
Arizona Electric Power Cooperative, Inc.[2]	95.2%	4.8%

[1] Information based on annual reports for the year ended 2003
[2] Based on the Company's rate filing

AEPCOS' TIER and DSC With Staff's Recommended Rates[1]

1	Operating Income	$ 17,755,095	**TIER**	
2	Depreciation & Amort.	$ 7,539,289	[1+3] ÷ [5]	1.33
3	Income Tax Expense	$ -	**DSC**	
4			[1+2+3] ÷ [5+6]	0.91
5	Interest Expense	$ 13,313,164		
6	Repayment of Principal	$ 14,360,494		

[1] The amounts reflect Staff's pro forma adjustments and the Applicant's proposed revenue

KEENE

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF) ARIZONA ELECTRIC POWER COOPERATIVE,) INC. FOR A RATE INCREASE)	DOCKET NO. E-01773A-04-0528

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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ARIZONA ELECTRIC POWER COOPERATIVE/
DOCKET NO. E-01773A-04-0528

Ms. Keene's testimony recommends that a fuel and purchased power cost adjustor be established for AEPCO but only with certain features and conditions. The base cost of fuel and purchased power be set at $0.01659 per kWh.

Ms. Keene's testimony recommends that AEPCO engage in cost-effective DSM programs. AEPCO should be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism. AEPCO should submit annual and quarterly DSM reports to the Commission.

Ms. Keene's testimony recommends new rates for AEPCO in order for AEPCO to recover Staff's recommended revenue requirements. These rates would result in an overall increase for Class A members of 7.8 percent. Mohave Electric's increase would be 15.3 percent, while the increase for the other distribution cooperatives would be 4.1 percent each.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of electric utility special contracts, review of utility tariff filings, assessment of utility demand-side management programs, and analysis of electric utility production costs and marginal costs. A copy of my résumé is provided in the Appendix.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket Nos. E-04100A-04-0527 and E-01773A-04-0528?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony is concerned with a fuel and purchased power cost adjustor, a demand-side management ("DSM") adjustor, and rate design for Arizona Electric Power Cooperative ("AEPCO").

FUEL AND PURCHASED POWER COST ADJUSTOR

Q. What has AEPCO requested in regard to an adjustor?

A. AEPCO (witness Gary Pierson's direct testimony, pages 14-15) has requested that the Commission approve an adjustor mechanism that would enable the recovery of increases and decreases in the fuel and purchased energy costs over which AEPCO has little control, without the time and expense of a rate case.

Q. Does AEPCO currently have a fuel and purchased power cost adjustor?

A. Not currently. AEPCO did have a Purchased Power and Fuel Adjustment Clause ("PPFAC") that was eliminated, at AEPCO's request, in Decision No. 64677 (March 27, 2002). The PPFAC, created in 1982, was a very complicated mechanism without clear understanding about its structure, leading to disagreements between AEPCO and Staff over the years. The PPFAC was discontinued as of August 1, 2001. However, at that time AEPCO indicated it would explore a revised adjustor mechanism in the future.

Q. How does AEPCO propose that the new adjustor mechanism work?

A. Mr. Pierson's direst testimony, page 15, suggests that an adjustor base be established in this rate case and that changes from the base would be tracked monthly and recouped as a positive or negative charge in the next quarter's billing to the Class A members. The base cost (AEPCO's Schedule H-2A) would include fuel costs (less fixed costs), purchased power energy costs , and non-firm wheeling costs. The costs would be offset by the fuel cost recovery portion of non-tariff sales. In response to BEK 16-3, Mr. Pierson has changed the request for a quarterly adjustment to a semi-annual adjustment.

Q. What is Staff's position regarding an adjustor mechanism?

A. Staff is not opposed to the establishment of a Fuel and Purchased Power Cost Adjustor ("FPPCA") with certain features and conditions.

Q. Please describe the structure of the adjustor mechanism that Staff would not oppose.

A. The FPPCA would track changes in the cost of fuel for AEPCO's generating units and power purchased from others. The adjustor rate would be calculated by comparing the rolling 12-month average of actual fuel and purchased power costs to the base cost established in this rate case. The rate would be applied to customer bills as a kilowatt-hour (kWh) charge.

Q. What cost components would be included in the adjustor?

A. The cost components would be the costs recorded in RUS Accounts 501 (fuel costs for steam power generation, less legal fees, less fixed fuel costs except for gas reservation), 547 (fuel costs for other power generation), 555 (purchased power costs, both demand and energy), and 565 (wheeling costs, both firm and non-firm). The prudent direct costs of contracts used for hedging fuel and purchased power costs may also be included. Power supply costs directly assignable to special contract customers would not be included in the calculation. Non-Class A sales for resale (RUS Account 447), less revenue for legal expenses, would be credited against the cost components.

Q. How does Staff's proposal differ from AEPCO's proposal regarding the components in the adjustor?

A. Staff proposes to include gas reservation charges, demand charges for purchased power, firm wheeling costs, and non-energy charge revenue from non-Class A sales for resale that AEPCO did not propose to be included in the adjustor.

Q. Why is Staff proposing that those items be included?

A. Gas reservation charges should be included because they are a part of the cost of obtaining natural gas for operating power plants.

Demand charges for purchased power should be included so that the method of cost recovery does not influence decision making when negotiating contracts. Some contracts in the marketplace are structured with only a per kWh energy charge that would include capacity costs. Other contracts are structured so that capacity costs are recovered through a per kW demand charge. AEPCO should negotiate these contracts so that they obtain the best deal for ratepayers. If only energy charges went into the adjustor, the method of cost recovery could influence the resulting structure of the contracts.

Firm wheeling costs should be included in the adjustor because they should be considered when negotiating purchased power and wheeling contracts. If only non-firm wheeling costs were included in the adjustor, the method of cost recovery could influence the type of contract that AEPCO would negotiate.

Including all revenue from non-Class A sales for resale as an offset to costs allows the Class A members to benefit from the margins of those sales. Since Class A members pay for the costs of the resources, it only seems fair that they benefit from the non-Class A sales.

Q. How often would the adjustor rate be reset?

A. The adjustor rate, initially set at zero, would be reset semi-annually on October 1, 2006, and April 1, 2007, and thereafter on October 1 and April 1 of each subsequent year. AEPCO would submit a publicly available report, with a revised tariff, that shows the calculation of the new rate on September 1, 2006, and March 1, 2007, and thereafter on September 1 and March 1 of each subsequent year. The adjustor rate would become effective with billings for October and April unless suspended by the Commission.

Q. Are the above dates different from those proposed by AEPCO?

A. Yes. Staff changed the dates to have the new rates go into effect before the winter season and before the summer season, taking into account the probable time for a Commission decision in this case.

Q. Would there be a balancing account?

A. Yes. The dollars associated with the calculation of the adjustor rate would be accumulated in a balancing account.

Q. At what amount should the base cost be set?

A. The base cost of fuel and purchased power would be set at $0.01657 per kWh. Derivation of the base costs is shown in Appendix 2.

Q. Would the structure of the FPPCA have the same problems as the old PPFAC?

A. No. The old PPFAC required that individual supply resources be matched to specific customer classes, without a clear-cut method of how to do it. The new FPPCA would not require the matching because all of the costs of resources are added together, and all of the non-Class A member sales are credited against the costs.

Q. Please describe Staff's recommended conditions.

A. Staff is not opposed to an adjustment mechanism with the following conditions:

1. **The FPPCA would expire in five years unless it is extended by the Commission.** AEPCO would file a report that addresses the FPPCA's operation, its merits, and its shortcomings and that provides recommendations as to whether the FPPCA should remain in effect. In order to allow time for review of the adjustor before the five-year expiration date, the report should be filed in its next rate case application or no later than four years from the effective date of implementation of the FPPCA. The Commission would consider whether to continue the FPPCA after AEPCO has filed its FPPCA report or during AEPCO's next rate case, whichever comes first.

2. **The Commission or its Staff would have the right to review the prudence of fuel and power purchases at any time.** Conducting a prudence review involves reviewing the utility's purchasing activities both as individual transactions and as an overall supply portfolio, generating unit performance, and other related issues. Such a review would consider what the utility knew or should have known at the time actions were taken. Prudence reviews can be time consuming. In light of

these issues, the Commission should not be limited as to when it may conduct a prudence review of AEPCO's purchasing practices.

3. **The Commission or its Staff would have the right to review any calculations associated with the FPPCA at any time.** The Commission needs the flexibility to monitor the calculations on a frequent and regular basis to ensure clarity and the correctness of those calculations for the ratepayers.

4. **Any costs flowed through the FPPCA would be subject to refund if the Commission later determines that the costs were not prudently incurred.** This condition would give AEPCO an incentive to minimize costs.

5. **AEPCO would file monthly reports to Staff's Compliance Section detailing all calculations related to the FPPCA.** The first report would be due 60 days from the effective date of a Commission order in this rate case. Thereafter, these reports would be due on the first day of the third month following the end of the reporting month for which the information applies. The reports would be publicly available and would contain, at a minimum, the following items:

   a. bank balance calculation, including all inputs and outputs;
   b. total power and fuel costs;
   c. Class A member sales in both kWh and dollars by member;
   d. a detailed listing of all items excluded from the FPPCA calculations;
   e. a detailed listing of any adjustments to the reports;
   f. non-class A member sales;
   g. system losses in MW and MWh;
   h. monthly maximum demand in MW; and
   i. identification of a contact person and phone number from AEPCO for questions.

6. **AEPCO would file additional monthly reports with Staff providing information on AEPCO's generating units, power purchases, and fuel purchases.** The first report would be due 60 days from the effective date of a

Commission order in this rate case. Thereafter, these reports would be due on the first day of the third month following the end of the reporting month for which the information applies. The reports may be provided confidentially.

The information for each generating unit would include, at a minimum, the following items:

a. net generation, in MWh per month, and 12 months cumulatively;
b. average heat rate, both monthly and 12-month average;
c. equivalent forced outage rate, both monthly and 12-month average;
d. outage information for each month, including event type, start date and time, end date and time, and description;
e. total fuel costs per month;
f. fuel cost per kWh per month;

At a minimum, the information on power purchases would consist of the following items per seller:

a. quantity purchased in MWh;
b. demand purchased in MW to the extent specified in contract;
c. total cost for demand to the extent specified in contract; and
d. total cost for energy.

Information on economy interchange purchases could be aggregated. These reports would also include an itemization of off-system sales.

At a minimum, the information on fuel purchases would consist of the following information:

a. natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge and incremental cost; and

b. natural gas commodity costs, categorized by short-term purchases (one month or less) and long-term purchases, including price per therm, total cost, supply basin, and volume, by contract.

7. **An AEPCO Officer would certify under oath that all information provided in the required reports is true and accurate to the best of his or her information and belief.** The Officer should be high level, either Chief Executive Officer, Chief Operating Officer, or Chief Financial Officer.

8. **AEPCO should file a plan of administration that describes how the FPPCA would operate.** The plan would be filed for Staff review within 30 days of a decision in this rate case.

DEMAND-SIDE MANAGEMENT

<u>Benefits of DSM</u>

Q. What is DSM?

A. DSM is the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner.

Q. Does AEPCO and the rest of society benefit from having DSM programs?

A. Cost-effective DSM programs can meet the demand for electric energy services at a lower cost than purchasing or generating power. Reduced peak demand can delay the need for construction of new generation and transmission facilities. In addition, reducing energy needs reduces the operating costs of current generating facilities. Reduced energy production may also lead to reduced air emissions from power plants, reduced consumption of water by generating unit cooling towers, and reduced degradation of land at mining sites.

Q. Why should AEPCO and Staff consider the benefits and costs of DSM to society rather than just to AEPCO?

A. We are seeking the least cost means of meeting the demand for electric energy services. A program that is not least cost wastes society's resources. Because customer costs and new generation costs may not be part of AEPCO's costs, we need to look beyond AEPCO's costs and benefits. The Commission adopted the use of the societal cost test in its resource planning decision (Decision No. 57589).

Q. What are the societal benefits of a DSM program?

A. From a societal perspective, relevant benefits come from avoiding new generating, transmission, and distribution capacity and avoiding burning of fuel and other variable costs. Because existing power plants have already been built and the associated societal costs have already been incurred, the fixed costs of existing power plants are sunk costs which cannot be avoided by a reduction in the demand for kW and kWh. Therefore, the only costs to society that can be avoided by DSM are those associated with the construction of new capacity and the variable costs associated with the generation of additional electricity.

Q. How can the societal costs of a DSM program be calculated?

A. The costs to society to implement a DSM program are the incremental costs of any equipment, including installation and operating costs, and program administrative costs. Incentives offered to customers to participate are not societal costs, but are transfer payments (transfers of income from one person or organization to another without supplying goods or services for these payments).

Q. Does AEPCO currently have any DSM program?

A. No. According to AEPCO's response to BEK 5-6, AEPCO currently does not administer or coordinate member distribution cooperative DSM programs. Following the

Commission's suspension of most of the Resource Planning rules in 1997, the institution of various DSM programs by some of AEPCO's member distribution cooperatives, and the cancellation of its PPFAC (which included a DSM component), AEPCO phased out its involvement in DSM programs.

Q. What DSM programs should AEPCO pursue?

A. AEPCO should evaluate possible DSM programs, considering the costs and kW and kWh savings associated with each program. AEPCO should then select the most beneficial and cost-effective projects to pursue. Ideally, AEPCO should engage in DSM programs as long as the incremental societal benefits (deferred capacity, avoided fuel costs, and avoided environmental impacts) are greater than the incremental cost of those programs to society.

Because AEPCO is a wholesaler, it should work with its member distribution cooperatives to develop and implement programs as was done in the past.

<u>Cost Recovery of DSM Programs</u>

Q. What cost recovery mechanisms could be used to recover AEPCO's DSM costs?

A. Possible mechanisms include using a deferral account with amortization into base rates, simply putting a level of costs in base rates, recovery through any fuel and purchased power adjustor approved for AEPCO, or setting up a separate DSM adjustment mechanism.

Q. Should AEPCO recover its DSM costs through a deferral account with base rate amortization?

A. No. When a deferral account is used, pre-approved DSM costs are placed in the deferral account and earn interest until the utility's next rate case, when the costs are considered for base rate cost recovery. If there are significant DSM activities taking place, the deferral account balance grows quickly, including the attendant interest, and can become a major cost which has to be dealt with in the utility's next rate case. In addition, a deferral account may not allow for the timely recovery of DSM costs to the same extent as some other cost recovery mechanisms.

Q. Should AEPCO recover its DSM costs directly through base rates with no deferral accounting?

A. No. Placing DSM costs in base rates does not provide the Commission and AEPCO with flexibility to increase or decrease DSM spending, as circumstances dictate. Additionally, a utility could choose to end its DSM activities, and there would be no way to remove the DSM funding from base rates until the next rate case.

Q. Should AEPCO recover its DSM costs through a fuel and purchased power adjustor (if approved for AEPCO)?

A. No. While recovery of DSM costs through a fuel and purchased power adjustor would provide timely and more flexible cost recovery, it would complicate the administration of the fuel and purchased power adjustor.

Q. How should AEPCO recover its costs for DSM programs?

A. Staff recommends that AEPCO be allowed to recover its costs for pre-approved DSM programs through a separate DSM adjustment mechanism. Recovery of pre-approved DSM costs through a DSM adjustment mechanism would provide the flexibility to adjust the level of DSM spending as needed in the future, while also providing timely recovery of pre-approved DSM costs. It would also provide a separate and specific accounting for pre-approved DSM costs.

A DSM adjustment mechanism would allow the costs associated with pre-approved programs to be recovered as the level of expenses associated with those programs changes. In addition, separating these expenses from other expenses included in base rates provides an incentive to initiate programs at any time rather than in the context of a rate case.

Q. How would customers be billed?

A. The DSM adjustment mechanism, as a charge per kWh, would be included on customer bills as a separate line item.

Q. How would the proposed DSM adjustment mechanism work?

A. The proposed DSM adjustment mechanism would consist of an account where the costs for pre-approved DSM programs would be recorded for each program by AEPCO as the costs were incurred. Revenues received through the DSM adjustor would be credited to the account. The per kWh adjustor rate would initially be set at zero. By February 1 of each year, AEPCO would file a request and supporting documentation with Staff to set a new adjustor rate to be effective on March 1. The new rate would be calculated by dividing the account balance by the number of kWh used by customers in the previous calendar year.

Q. What kinds of costs should AEPCO be able to recover?

A. Staff recommends that AEPCO recover the program costs associated with pre-approved DSM projects. Program costs include administrative expenses, monitoring expenses, any incentives such as rebates, promotional expenses, educational program expenses, and the costs of demonstration facilities.

Implementation of DSM Programs

Q. How should AEPCO implement DSM programs?

A. AEPCO should submit proposed programs to the Commission for approval. After a program is approved, AEPCO may begin entering the costs for that program as they are incurred into the DSM adjustment mechanism account.

Q. What should AEPCO include in a DSM program proposal?

A. The proposal should include a description of the program, objectives and rationale for the program, identification of the market segment at which the program is aimed; expected level of program participation, an estimate of the baseline, estimated societal benefits and savings from the program, estimated societal costs of the program, marketing and delivery strategy, utility costs and budget, an implementation schedule, a monitoring and evaluation plan, and any proposed performance incentives.

Staff would consider whether the benefits of the measures to society exceed the costs to society. In addition, Staff would consider the reasonableness of any customer incentives proposed by AEPCO. Staff would then provide the Commission with a recommendation regarding the DSM proposal. New programs could be added or existing programs terminated anytime during the year subject to Commission approval.

Q. Why should each program proposal include a monitoring and evaluation plan?

A. AEPCO should include a monitoring plan in each program proposal because AEPCO needs to monitor and evaluate all DSM programs to reliably ensure that they are cost-effective. Monitoring and evaluation should:

1. determine participation rates, energy savings, and demand reductions;
2. assess the utility's program implementation process;
3. provide information on whether to continue, modify, or terminate a program; and
4. determine the persistence and reliability of DSM.

Q. What are Staff's recommendations regarding monitoring?

A. If the monitoring activity reveals that the program is not working as well as expected, AEPCO should modify or terminate the program. AEPCO should file an application with the Commission about any plans to terminate a program before such termination occurs. AEPCO should provide its plans for notification to potential participants. If a program is terminated, AEPCO would be expected to give proper notice to potential participants as well as honor existing commitments.

Q. How can Staff and the Commission monitor AEPCO's efforts?

A. Staff recommends that AEPCO submit annual reports to the Commission containing, at a minimum, the following information separately for each program: a brief description of the program; predetermined program goals, objectives, and savings targets; the level of customer participation; costs incurred during the reporting period disaggregated by type of cost (such as administrative costs, rebates, and monitoring costs); a description of evaluation and monitoring activities and results; kW and kWh savings; benefits and net benefits in dollars; any program-specific performance incentive calculations; problems encountered and proposed solutions; and proposed program modifications. Findings from all research projects and other significant information should be included. Each annual report would be due on February 1, reporting for the previous calendar year.

Staff also recommends that AEPCO file quarterly reports that consist of a tabular summary of expenditures compared to the budget. Quarterly reports would be due on May 1 (for January through March), August 1 (for April through June), and November 1 (for July through September). Information on the last quarter of the year would be included in the annual report.

In addition, the Commission may review program costs and performance in future rate cases.

RATE DESIGN

Q. What do you recommend as AEPCO's rates for its Class A members?

A. Based on Staff's recommended revenue requirements, the rates should be set as follows:

	Full Requirements
Demand charge	$12.90 per kW of demand coincident with AEPCO monthly peak
Energy charge	$0.02079 per kWh used during billing period
	Partial Requirements
O&M charge	$7.48 per kW of allocated capacity based on coincident AEPCO demand
Energy charge	$0.02079 per kWh used during billing period
Fixed Charge	$707,392 per month for Mohave

These rates would result in an overall increase for Class A members of 7.8 percent. Mohave Electric's increase would be 15.3 percent, while the increase for the other distribution cooperatives would be 4.1 percent each.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A.
1. Staff recommends that a fuel and purchased power cost adjustor be established for AEPCO but only with certain features and conditions.
2. Staff recommends that the base cost of fuel and purchased power be set at $0.01659 per kWh.
3. Staff recommends that AEPCO engage in cost-effective DSM programs.
4. Staff recommends that AEPCO be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism.
5. Staff recommends that AEPCO submit annual and quarterly DSM reports to the Commission.

6. Staff recommends new rates for AEPCO in order for AEPCO to recover Staff's recommended revenue requirements. These rates would result in an overall increase for Class A members of 7.8 percent. Mohave Electric's increase would be 15.3 percent, while the increase for the other distribution cooperatives would be 4.1 percent each.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003; Staff Report on Code of Conduct.

Arizona Public Service Company Rate Case (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004; testimony on demand-side management, system benefits, renewable energy, the Returning Customer Direct Assignment Charge, and service schedules.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

"DSM Workshop Progress Report," Arizona Corporation Commission, 2004.

(with Erin Casper) "Staff Report on Demand Side Management Policy," Arizona Corporation Commission, 2005.

Appendix 2

Base Cost of Fuel and Purchased Power
for AEPCO Adjustor

RUS Account			
501	fuel costs for steam power generation		$46,830,878
	less MEC Schedule A adjustment		-550,220
	less City of Mesa adjustments		-407,498
	less legal fees		-1,030,873
	less fixed fuel costs (except gas reservation)		-295,865
			$44,546,422
547	fuel costs for other power generation		**$15,464,540**
555	purchased power costs (demand & energy)		$16,270,579
	less MEC Schedule A adjustment		-333,790
	less City of Mesa adjustments		-169,803
	plus Purchase Power adjustment		88,139
	less PNM adjustment		-250,000
			$15,605,125
565	wheeling costs (firm & non-firm)		$8,036,486
	plus wheeling contract adjustment		-19,560
			$8,016,926
		Costs	***$83,633,013***
447	non-Class A sales for resale		$51,757,181
	plus MEC Schedule B reclassification		142,921
	less City of Mesa adjustments		-903,664
	less revenue for legal expenses		-923,826
		Revenues	***$50,072,612***
	Base Cost (Costs-Revenues)		**$33,560,401**
	Class A kWh sales		2,025,326,533
		$/kWh	**$0.01657**

J. SMITH

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF) ARIZONA ELECTRIC POWER COOPERATIVE,) INC. FOR A RATE INCREASE)	DOCKET NO. E-01773A-04-0528

DIRECT

TESTIMONY

OF

JERRY D SMITH

ELECTRIC UTILITY ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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EXHIBITS

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE
DOCKET NO. E-01773A-04-0528

Arizona Electric Power Cooperative ("AEPCO") filed a rate application with the Arizona Corporation Commission ("ACC or Commission") on July 23, 2004. The 2003 calendar year was selected by AEPCO as its test-year for all rate making revenues, rate based utility plant, and operating expenses. This testimony solely concerns the rate based utility plant. AEPCO adjusted its 2003 rate based utility plant to include a coal blending facility constructed following the test-year but preceding its July 2004 rate application.

The justification of need for all AEPCO rate based utility plant constructed since October 2002 is addressed in this testimony. Commission witness, Jerry D. Smith, reaffirms the justification of need for such facilities established in prior Commission proceedings. His testimony concludes that all utility plant contained in AEPCO's rate application is used and useful.

WITNESS BACKGROUND AND QUALIFICATION

Q. Please state your name, occupation, and business address.

A. My name is Jerry D. Smith. I am an Electric Utility Engineer employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University in 1977 majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Briefly describe your responsibilities as an Electric Utility Engineer.

A. I joined the Commission's Utilities Division Staff as an electric engineer in 1999. In my capacity as an Electric Utility Engineer, I have investigated the quality of service provided by electric utilities in Arizona and been responsible for three biennial transmission assessments regarding the reliability of existing and planned Arizona transmission facilities. During my employment at the Commission, I have investigated numerous system disturbances on behalf of the Commission. A 1999 blackout of Southern Arizona, a 2001 blackout of Gila Bend, and several extra high voltage ("EHV") disturbances occurring in 2003 and 2004 are among the system disturbances I have investigated. My most recent investigations were of the Westwing and Deer Valley Substation fires.

I chaired a series of Commission Distributed Generation workshops in 1999 and have participated in the revision and application of electric retail competition rules throughout Arizona. I have also inspected physical electric utility plant consisting of generation, transmission and distribution facilities. Such facility inspections were necessary to make a "used and useful" determination for rate case applications and to ascertain the level of security, safety, operational integrity, and maintenance exhibited by such facilities.

Q. Please describe other pertinent work experience.

A. I have over 27 years of experience as an engineer and manager in the electric utility industry. I was employed by the Salt River Project from 1968 through 1995. During that time I: 1) analyzed and planned transmission and distribution system improvements; 2) managed the design and consultation services required for retail customer projects; and 3) served as primary contact for local municipalities regarding siting of facilities and utilizing funds for aesthetic treatment of water and power facilities. I also performed ancillary functions such as development and management of capital improvement budgets; formation and modification of system planning, operational and maintenance policies, procedures and practices; and creation, modification and administration of new contribution in aid of construction charges and tariffs.

Q. Have you previously testified before this Commission?

A. Yes. I have extensive experience testifying before the Commission. I have testified on numerous occasions regarding quality of service to electric customers in the City of Nogales and Santa Cruz County. I was a Staff witness regarding the 2003 competitive wholesale power solicitations required by the Commission. I have provided testimony for over 35 power plant and transmission line applications for a Certificate of Environmental Compatibility. My experience filing engineering reports and providing testimony for the

Commission in rates cases is most applicable to this case. I have provided engineering reports and rate case testimony for Duncan Valley Electric Cooperative, Navapache Electric Cooperative, and the Arizona Public Service Company and an Open Access Transmission Tariff ("OATT") case for Southwest Transmission Cooperative.

PURPOSE AND PREPARATION OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. I am providing testimony concerning the security, safety, operational integrity, and maintenance status of AEPCO's Apache Station power plant. My testimony considers both test-year facilities and *post* test-year facilities filed by the applicant for inclusion in this rate case. This testimony documents the justification of need previously considered by this Commission for all new *post* test-year capital improvements proposed for inclusion in the rate base by AEPCO. Finally my testimony determines to what degree the test-year and post test-year AEPCO facilities are "used and useful."

Q. How have you prepared for your testimony?

A. I have reviewed information on file, issued data requests to AEPCO, inspected AEPCO's Apache Station generating plant and talked with AEPCO, Southwest Transmission Cooperative ("SWTC") and Sierra Southwest Cooperative Services ("Sierra Southwest") personnel.

Q. When did you inspect AEPCO's facilities?

A. I inspected AEPCO's Apache Station and all on-site facilities appurtenant to the power plant during a December 9, 2004 site visit. A summary report of my findings is attached as Exhibit JS-3.

Q. What AEPCO, SWTC and Sierra Southwest personnel have you talked with concerning this docket?

A. I have talked with Mr. Dirk Minson, Chief Financial Officer; Mr. Gary Pierson, Financial Services Manager; Mr. Larry Huff, General Manager; Mr. Gary Grim, Transmission Engineering Manager; Mr. Mark Schwirtz, Plant Manager; and Mr. Charles Walling, Generation Engineering Manager.

Q. What documentation have you reviewed in preparing your testimony?

A. I have reviewed all rate application material filed by the applicant and numerous responses to Staff data requests. I also reviewed testimony and ACC engineering reports filed for two prior AEPCO power plant financing applications[1]. ACC engineering reports for the two respective financing cases are attached as Exhibit JS-1 and Exhibit JS-2.

Q. Is your testimony herein based upon the aforementioned facility site observations, conclusions drawn from review of available documentation, information gathered by talking with applicant personnel and your educational background and work experience as a utility professional?

A. Yes it is.

FACILITIES CONSIDERED IN TESTIMONY

Q. Have you reviewed AEPCO's application and testimony regarding facilities it proposes to include in rate base for this case?

A. Yes. I reviewed AEPCO's Schedule E-5 that provides a detailed account of utility plant. AEPCO witness, Mr. Dirk Minson's testimony indicates that the addition of a new

[1] Docket No. E-01773A-01-0701 and Docket No. E-01773A-02-0112.

Combustion Turbine Unit 4 ("CT4") in October 2002 and the addition of a coal blending facility are among the primary reasons for requesting a rate increase.

Q. What other facilities are considered in your testimony?

A. AEPCO's Schedule E-5 also includes other recent capital improvements contained in AEPCO's 2001-2004 Construction Work Plan. ACC Engineering Staff reviewed AEPCO's construction plans at the time of its 2001 and 2002 financing applications with this Commission. Those facilities include four key capital improvements:

1. Consolidation and upgrade of controls in a common control room for Apache Steam Turbine Units 1, 2 and 3,
2. A deluge fire protection system for Steam Turbine Units 2 and 3 cooling towers,
3. A new coal blending system, and
4. A deep well system upgrade to replace the well displaced by the new coal blending system.

The Combustion Turbine Unit 4 construction was completed in October of 2002. All of other capital improvements, with the exception of the coal blending system, were constructed in 2002 and 2003. The coal blending facility was completed in April of 2004.

JUSTIFICATION OF NEED FOR RECENT IMPROVEMENTS

Q. Briefly describe how AEPCO established with the Commission a justification of need for Combustion Turbine Unit 4.

A. AEPCO filed a financing application with the Commission in 2001 for funds to construct Combustion Turbine Unit 4.[2] Exhibit JS-1 is a copy of the Engineering Report filed by Staff in that case. That report offers numerous citations that document the need for the

[2] Docket No. E-01773A-01-0701.

new 38 Megawatt ("MW") generator. AEPCO's inability to meet its generating reserve requirements beginning in 2001 were first exposed to the Commission at an Energy Workshop held on February 16, 2001. The generator did not become operational until October 2002. This means APCO was deficient in generating reserves for a period of two years.

AEPCO provided further justification of need for the CT4 generator via Sections 8, 17, 18 and 19 of Rural Utility Service ("RUS") and Capital Financing Corporation ("CFC") financing materials. AEPCO filed those materials in support of its financing application with the Commission. ACC Staff concluded in an Engineering Report[3] that "AEPCO was pursuing the only option available to meet its short-term generation reserve requirements." The report also noted the $30 million estimated cost of the proposed project was consistent with costs of similar facilities constructed by others. The Commission approved the requested financing for this project.

Q. Briefly describe how AEPCO established with the Commission a justification of need for other recent major capital improvements.

A. AEPCO filed a financing application with the Commission in 2002 for funds to construct its other recent capital improvements.[4] Exhibit JS-2 is a copy of the Engineering Report filed by Staff in that case. The report determined that the proposed improvements would favorably impact the reliability, plant efficiency and operational economics of Apache Station. Upgrades of Apache Station controls would improve combustion efficiencies, reduce spare parts and increase unit reliability. Installing a fire deluge protection system for Steam Turbine Unit 2 and 3 cooling towers would reduce the risk of fires. The coal blending system would provide the capability to blend coal from three sources to achieve

[3] Exhibit JS-1.
[4] Docket No. E-01773A-02-0112.

an optimal fuel blend from both an economic performance and an emissions standpoint. The deep well system improvements were necessary to replace a well displaced by the coal blending project and gain access to the aquifer at a greater depth. ACC Engineering Staff found the proposed Apache Station improvements to be appropriate and necessary given the age and operational status of the existing facilities. Nevertheless, Staff deferred a "used and useful" determination *until* such time that AEPCO filed for a rate adjustment[5]. The Commission approved the requested financing authority for these capital improvement projects.

USED AND USEFUL DETERMINATION

Q. Please describe how you determined if all of the capital improvements addressed by your testimony were used and useful.

A. On December 9, 2004, I toured the Apache Station power plant. I observed all of the AEPCO capital improvements for which justification of need had been previously established with the Commission and for which the Commission had approved financing authority. Photos were taken to document my observations and are attached to the Engineering Report of the site visit. This report is attached as Exhibit JS-3.

Q. Please summarize your observations of the Apache Station facilities.

A. I observed each of the 7 generating units, the natural gas and coal fuel supply facilities, the power plant water facilities and the emergency equipment and supplies. The power plant complies with National Electric Safety Code ("NESC") security and safety requirements. All of the generating units were operational. All natural gas and coal facilities were observed to be operational and well maintained. The associated fuel was secure and safely managed. The new coal blending facilities appeared well designed and effectively

[5] Exhibit JS-2.

integrated into the pre-existing infrastructure. With the exception of an inactive ash pond, all plant water facilities were observed to be operational, in use and adequately maintained. The inactive ash pond is to be retired at some future date once financing is authorized.

During my tour of the plant, I observed that personnel seemed well trained to respond to both operational and emergency events. The improved control room SCADA equipment, operational controls, informational displays, computers, and communication equipment enabled operating personnel to quickly respond to a boiler feed pump problem while I toured the control room. The plant has appropriate and sufficient emergency medical and fire fighting equipment and sufficient supplies to effectively manage emergency events as well. Furthermore, the site is being managed with a primary focus on personnel safety and operational safety.

Q. Has Staff determined if the capital improvements made by AEPCO are "used and useful?"

A. Yes. All facilities observed during my December 9, 2004 tour of Apache Station were operational and well maintained. The inactive ash pond is planned for retirement. The new CT4 generator, new control room and controls for Steam Turbine Units 1, 2 and 3, the new coal blending facilities, the fire protection upgrades, and deep well system for plant water needs all appear well designed and constructed to comply with current industry standards. Therefore, the subject AEPCO power plant facilities are found to be used and useful.

SUMMARY OF TESTIMONY CONCLUSIONS

Q. Please summarize the conclusions of your testimony.

A. Utility plant improvements constructed by AEPCO between October 2002 and July 2004 were appropriate and necessary to maintain reliable, efficient and cost effective service to its members and the wholesale market. The justifications of need for such facilities were established before the Commission in prior proceedings. All utility plant contained in AEPCO's rate application is "used and useful" in supplying the energy needs of existing retail customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit JDS-1

Memorandum

To: Jim Johnson, Auditor III, Utilities Division
From: Jerry D. Smith, Electric Utilities Engineer, Utilities Division
Thru: Del Smith, Engineering Supervisor, Utilities Division
Subject: AEPCO Financing Application, Docket No. E-01773A-01-0701
Date: October 2, 2001

Arizona Electric Power Cooperative ("AEPCO") filed an application on September 4, 2001, for authority to incur debt and secure liens on its property for the financing of a new Combustion Turbine Unit 4. AEPCO proposes to borrow an amount not to exceed $30 million from either the National Rural Utilities Cooperative Finance Cooperative and/or the Rural Utilities Service. Engineering Staff (Engineering) has reviewed the most recent AEPCO financing application and AEPCO's response to Commission Staff data requests. Engineering offers the following assessment.

AEPCO first documented its inability to meet it generating reserve requirements beginning in 2001 at the ACC Energy Workshop 2001-2002 held on February 16, 2001. The generating reserves deficiency is further substantiated by Section 8 of AEPCO's Fast Track A Materials for RUS/CFC. AEPCO has documented the need for the proposed 38 MW combustion turbine generator very effectively in Section 3 of the same RUS/CFC material. In fact, AEPCO documents that it was unable to arrange cost-effective purchase power alternatives from the new Calpine South Point Power plant or the new Griffith Power Plant because of their intent to sell only at the commodity price (spot market).

AEPCO also provided excellent documentation in Sections 17 and 18 of its RUS/CFC material of its fuel supply / delivery arrangements and its commitment to appropriate emission control technology. In Section 19, AEPCO documents the various transmission line constraints that impede its ability to purchase or deliver to others. Engineering concludes AEPCO is pursuing the only option available to meet its short-term generation reserve requirements. AEPCO's documentation serves as a good model of what Engineering would appreciate seeing in large power plant Certificate of Environmental Compatibility applications regarding project need, adequate and reliable transmission capacity and fuel supply / delivery capability.

Engineering finds no technical flaws in AEPCO's application for financing of a 38 MW combustion turbine generator. The cost estimate of the proposed project is consistent with cost of similar facilities constructed by others.

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JDS

CC: Steve Olea, Acting Director, Utilities Division
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Memorandum

To: Jim Johnson, Auditor III, Utilities Division
From: Jerry D. Smith, Electric Utilities Engineer, Utilities Division
Thru: Del Smith, Engineering Supervisor, Utilities Division
Subject: AEPCO Financing Application, Docket No. E-01773A-02-0112
Date: August 2, 2002

Arizona Electric Power Cooperative ("AEPCO") filed an application on February 11, 2002, for authority to incur debt and secure liens on its property for the financing of necessary improvements at the Apache Generating Station. AEPCO proposes to borrow interim funds not to exceed $30,588,576 from the National Rural Utilities Cooperative Finance Corporation ("CFC") and $26,764,000 to repay the interim CFC loan when permanent loan funds are available from the Rural Utilities Service ("RUS") guaranteed Federal Financing Bank ("FFB"). Engineering Staff ("Engineering") has reviewed the most recent AEPCO financing application and offers the following technical assessment.

Engineering has reviewed AEPCO's revised 2001-2004 Construction Work Plan filed with its financing application. The work plan contains all power plant related improvements for which the loan is requested. The bulk of the loan is for four key improvements as depicted in the table below:

Table 1: Summary of Work Plan

RUS 740c Code	Project Name	Amount
1200.4	Apache Controls Upgrades	6,896,380.
1200.7	ST2&3 CT Fire Protection Upgrade	1,064,330.
1200.11	Coal Blending System	9,952,618.
1200.27	Deep Well System Upgrades and Land Purchase	3,687,836.
	Other Miscellaneous Items	5,163,157.
	TOTAL	$26,764,321.

The improvements address reliability, plant efficiency and operational economics of the existing Apache Station. The Apache Controls Upgrades will improve combustion efficiency, reduce spare parts inventory and increase reliability. The Fire Protection Upgrade for ST2&3 cooling towers will reduce the risk of cooling tower fires by installing a deluge fire protection system to replace the existing inoperative fire protection system. The Coal Blending System will provide the capability to blend coal from three sources to achieve a fuel blend that is optimal from both a performance and an emission standpoint. The Deep Well System Upgrade establishes a new well to replace the deep well that will be displaced by the Coal Blending Facility and gives access to the aquifer at a greater depth.

The remaining $5 million of improvements result in fuel diversity and delivery capability, improved emissions performance, unit efficiency improvements, and safety improvements. Oil burning capability for Combustion Turbine 2 is being re-established and a second fuel pipeline is being installed at the site to deliver fuel, backing up the gas obtained via El Paso Natural Gas under a full requirements contract. Coupling these improvements with the Coal Blending Facility assures AEPCO greater flexibility in negotiating fuel and delivery contracts to assure a reliable supply of fuel. This added flexibility is particularly of value in the existing economic climate where gas has been curtailed and is being reallocated on the El Paso pipeline. Many of the efficiency and emission improvements are likely to be viewed favorably during the air permitting process for the new Combustion Turbine 4 project which is not included in this loan package.

The Apache Station site has been experiencing uniform subsidence accompanied by some fissures at the periphery of the site. Similarly, the local aquifer is being depleted and the water table has been dropping at a rate of approximately 4-5 feet annually for the last five years. AEPCO indicates that neither of these conditions is unusual or problematic for the plant. Nevertheless, water and subsidence monitoring systems are in place.

Conclusion

Engineering finds the power plant improvements proposed for Apache Station in AEPCO's financing application to be appropriate and necessary given the age and operational status of the facilities. The cost estimates of the proposed projects are reasonable and are consistent with cost of similar facility improvements made by others in the power plant industry. However, Engineering defers judgement of all proposed improvements as "used and useful" until such time that AEPCO applies for a rate adjustment. A more thorough review of facilities will be undertaken at that time.

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JDS

CC: Steve Olea, Assistant Director, Utilities Division
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Memorandum

Date: February 11, 2005
To: File
From: Jerry D. Smith, Electric Utility Engineer
Subject: AEPCO Site Visit – December 9, 2004
Docket No. E-01773A-04-0528

I visited with Arizona Electric Power Cooperative ("AEPCO") and Southwest Transmission Cooperative ("SWTC") personnel on December 9, 2004. The purpose of the visit was to tour the Apache Power Plant, the Apache Substation, the new Winchester Substation, and a new Apache to Winchester 230 kV line to ascertain the operational status of new capital improvements contained in financing and rate application cases pending before the Arizona Corporation Commission ("ACC" or "Commission"). Gary Grim served as my host throughout the entire visit. We were joined by Mark Schwirtz and Charles Walling for the Apache Power Plant segment of the tour.

The following documents my observations of AEPCO's generation facilities during the site visit. It documents safety, security, and operation of the Apache Power Plant, new control room, coal blending facilities, new combustion turbine unit 4, ash ponds and fire protection equipment. Photos taken during this visit are attached as exhibits to document what was observed in the field regarding the subject power plant facilities.

Apache Station

The Apache Station power plant is located on highway 191 approximately 10 miles south of its intersection with the I-10 interstate highway. The entrance to the power plant is depicted in Figure 1 of Exhibit 1. The same figure depicts the three steam turbine units. Steam Turbine Unit 1, Combustion Turbine Unit 3 and the new Combustion Turbine Unit 4 are depicted respectively in Figures 3 through 6. Security personnel maintain security and access to the plant site on a twenty four hours per day basis. Figure 2 depicts the location of security personnel at the entrance gate. The entire site has perimeter chain link fencing topped with barbed wiring. The chain-link fence is 8 feet in height, the plant entrance gate is properly secured, and proper signage is displayed in both English and Spanish as observed in Figure 2. These power plant security features comply with National Electric Safety Code ("NESC") requirements.

Fuel Supply Facilities

Exhibit 2 contains photos depicting facilities that supply fuel for the various Apache Station generators. Figures 7 and 8 provide views of the natural gas facilities. The natural gas substation depicted in Figure 7 is properly enclosed by a chain link fence and the substation site is secured with a locked gate. The natural gas pipeline, owned and operated by El Paso Gas, is located to the south of the plant site and gas substation and runs in both an easterly and westerly direction. The pipeline corridor east of the plant is depicted in Figure 8.

Figures 9 through 12 depict the on-site coal facilities. The plant's coal stockpile is depicted in Figure 9 while the railcar coal dump conveyors and fuel blending facilities are depicted in Figure 10. The conveyors

for moving the blended coal to the respective generating units are depicted in Figure 11. The new coal blending addition is depicted in Figure 12.
All natural gas and coal facilities were observed to be operational and well maintained. The associated fuel was secure and safely managed. The new coal blending facilities were well designed, were effectively integrated into the pre-existing infrastructure and are operational, and well maintained.

Plant Water Facilities

Exhibit 3 depicts all of the major water facilities appurtenant to operation of a power plant. Figure 13 depicts a combustion waste disposal facility ("CWDF") or cooling water evaporation pond constructed north of the plant site in 1995. Meanwhile, Figure 14 shows the location of the old inactive CWDF or ash pond east of the plant site. Cooling towers in operation and use for the plant are depicted in Figures 15 through 17. A water supply tank and tower is also depicted in Figure 15. With the exception of the inactive ash pond, all water facilities were observed to be operational, in use and adequately maintained.

Emergency Readiness

Apache Station has a trained and certified emergency response team that can attend to medical emergencies, chemical spills or fires. The photos contained in Exhibit 4 depict facilities that enable effective on-site emergency and operational responses. The fire station depicted in Figure 17 stores all emergency vehicles and supplies. Emergency vehicles depicted in Figure 18 include a fire truck, a hazardous response truck, and a medical evacuation van. Figure 19 documents an ample supply of F-500 fire retardant stored in the fire house for use with electric fires. Fire fighting water is available from three sources: the water tower depicted in Figure 15, the well house containing a water feed pump depicted in Figure 20 or the Fire Truck storage tank.

Personnel operating and maintaining the power plant also exhibited an attention to details that is also indicative of their emergency readiness. The new control room for steam turbine units 1, 2 and 3 is depicted in Figure 21. While touring the control room I observed operating personnel respond to a boiler feed pump problem that tripped unit 3. The personnel appeared properly trained in responding to the event. Necessary Supervisory Control And Data Acquisition ("SCADA"), controls, informational displays, computers and communication equipment were available to enable other units to be timely ramped up in response to loss of unit 3.

It was evident that the lessons learned by the Westwing transformer fires of July 4, 2004 were being applied at this plant site. Figures 22 and 23 depict the step-up transformers that connect steam turbine units 1 and 2 to the Apache Substation. These transformers have foundations setting in a cement oil spill cache basin. The basins were clean and maintenance personnel were replacing soil containing combustible coal dust with new soil and gravel around the transformer foundations.

During tour of the plant facilities I observed that personnel are properly trained to respond to operational or emergency events. They have appropriate and sufficient equipment and supplies to effectively manage such events. Furthermore, the site is being maintained with a focus on personnel and operational safety as a priority.

Conclusions

Personnel were well trained and demonstrated operational safety and personnel safety were a priority. With the exception of the inactive ash pond, all facilities observed during the December 9, 2004 tour of AEPCO's Apache Station were operational and well maintained. The inactive ash pond is planned for retirement. The new Combustion Turbine Unit 3, new control room and controls for Steam Turbine Units 1, 2 and 3, the new coal blending facilities, the Fire Protection upgrades, and deep wells for power plant water needs all appear to be designed and constructed to comply with industry standards. Therefore, I conclude the subject AEPCO power plant facilities are "used and useful."

JDS/rdp

Attachment: Exhibits 1-4
cc: Ernest Johnson, Utilities Director
Steve Olea, Assistant Utilities Director
Del Smith, Engineering Supervisor

EXHIBIT 1
Apache Station Power Plant

Figure 1. Site Entrance

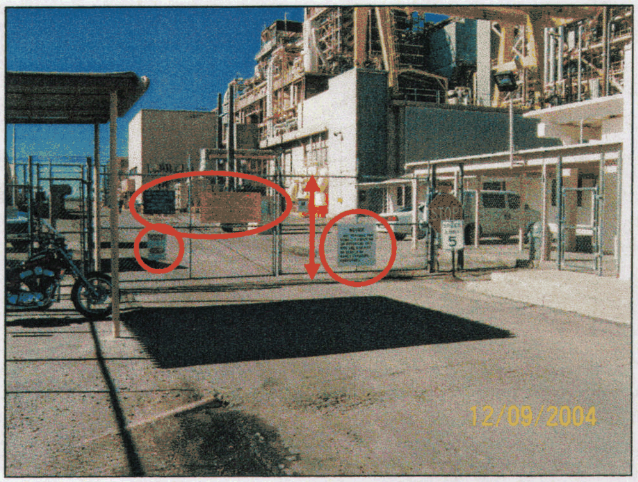

Figure 2. Gate and Signage

Figure 3. Steam Turbine Unit 1

Figure 4. Combustion Turbine Unit 3

Figure 5. Combustion Turbine Unit 4

Figure 6. Combustion Turbine Unit 4

EXHIBIT 2
Fuel Supply Facilities

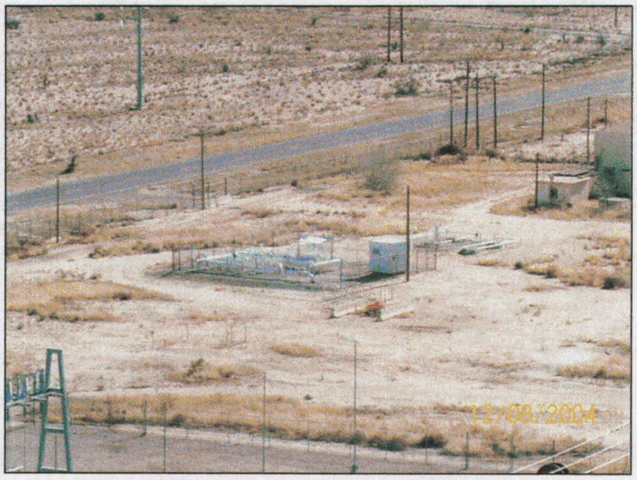

Figure 7. Natural Gas Substation

Figure 8. Natural Gas Pipeline Corridor

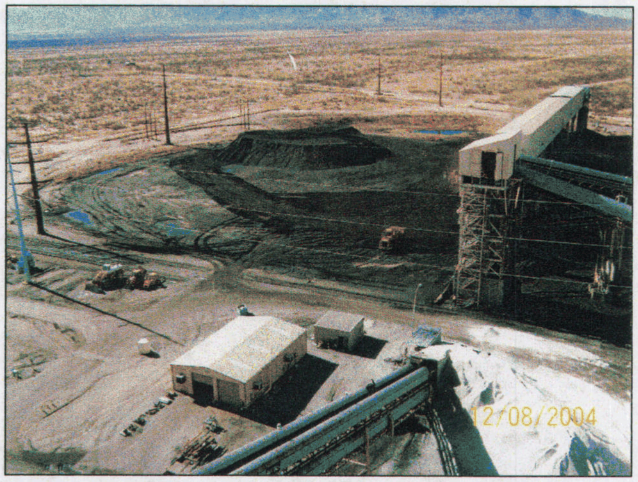

Figure 9. Coal Facilities

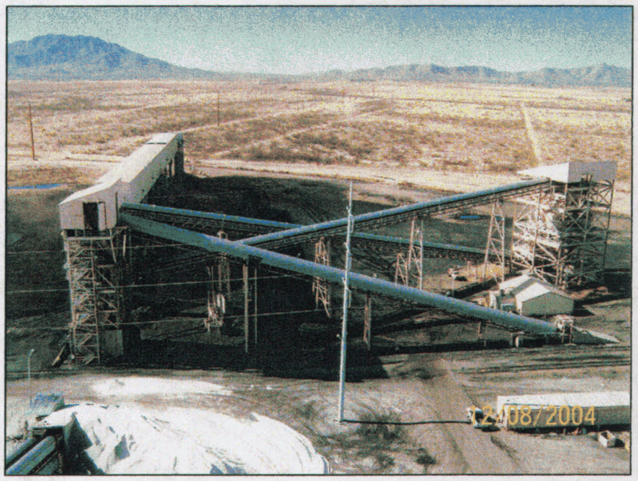

Figure 10. Coal Dump Conveyors

Figure 11. Coal Conveyors to Plant

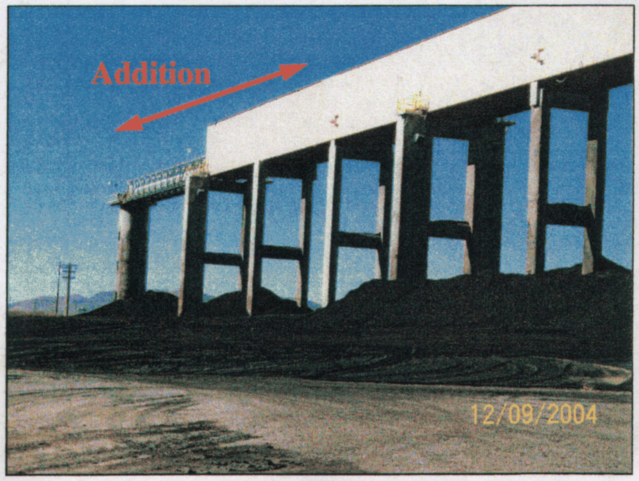

Figure 12. Coal Blending Facilities

EXHIBIT 3
Water Facilities

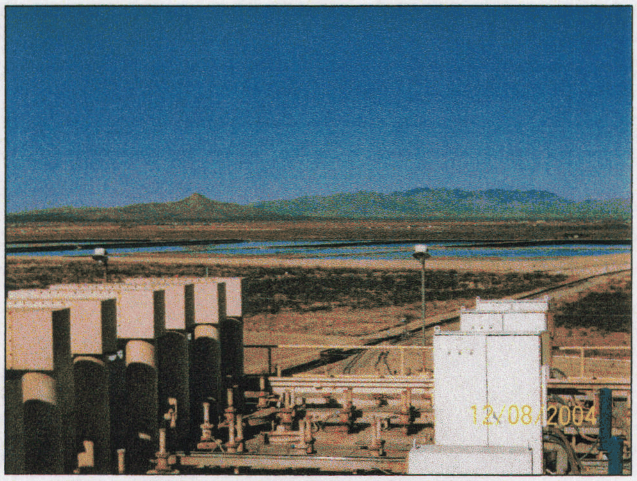

Figure 13. New Cooling Water Ponds

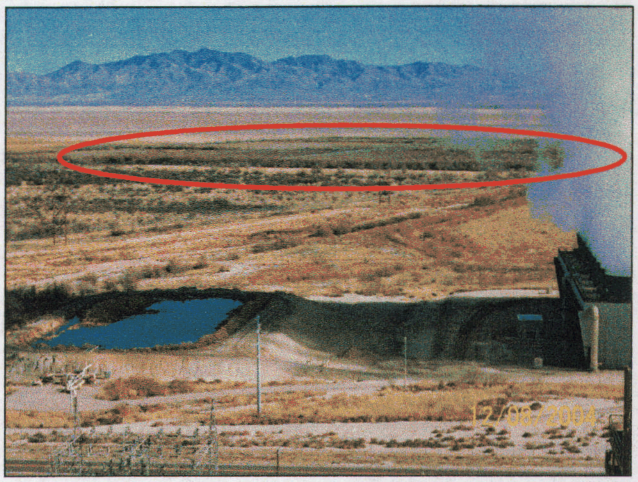
Figure 14. Inactive Ash Pond

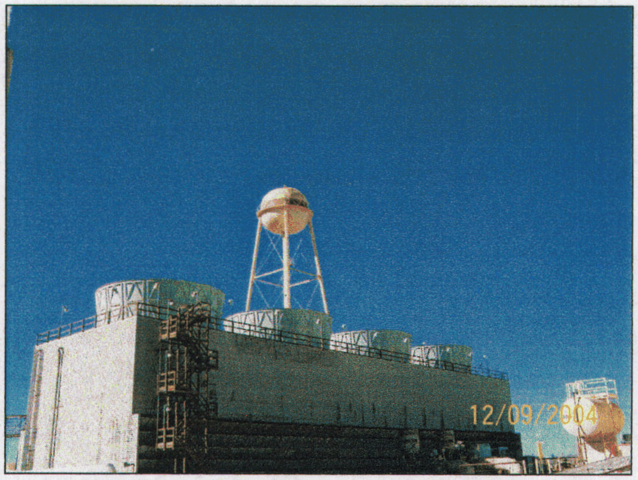

Figure 15. Water Supply Tank

Figure 16. Pair of Cooling Towers East of Plant

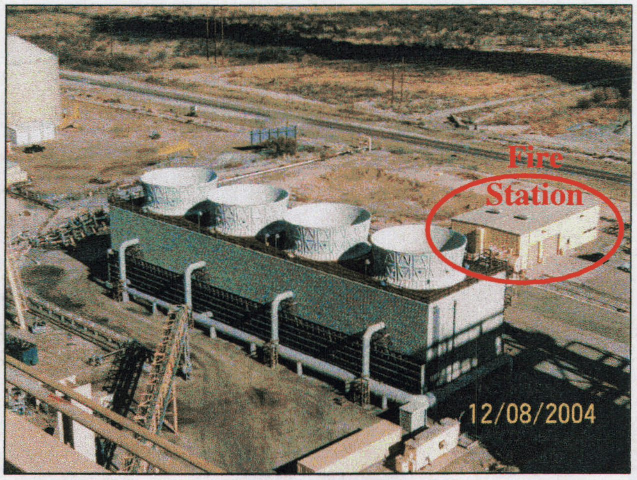

Figure 17. New Cooling Tower

EXHIBIT 4
Emergency and Fire Fighting Facilities

Figure 18. Fire Truck / Emergency Vehicles

Figure 19. F-500 Fire Retardant

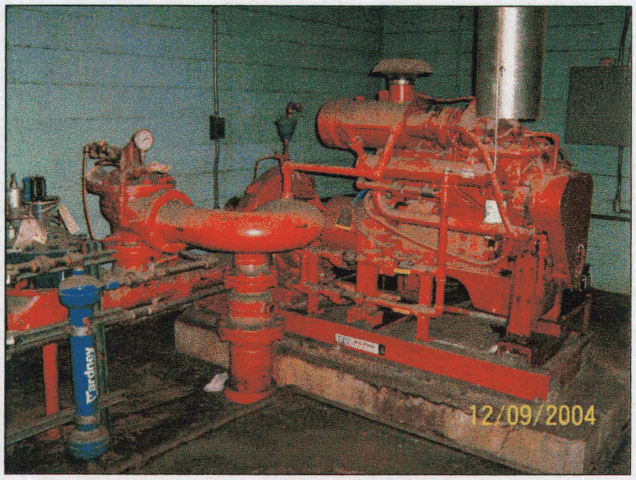

Figure 20. Fire Fighting Water Feed Pumps

Figure 21. Control Room

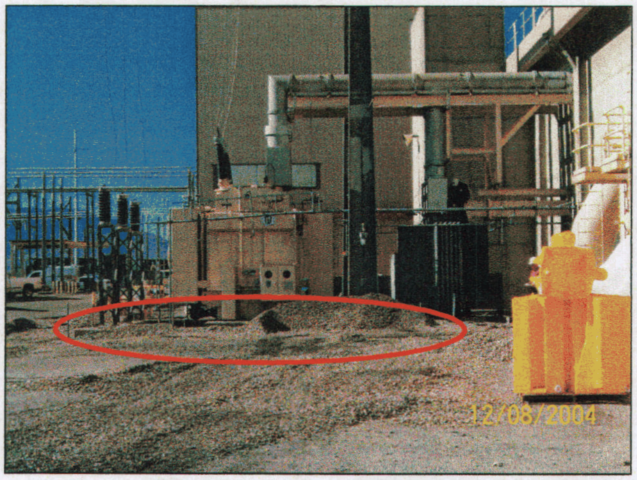

Figure 22. ST #1 Step-up Transformer

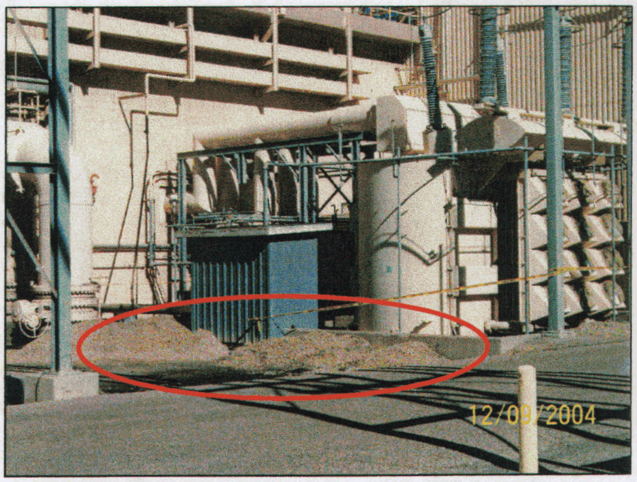

Figure 23. ST #2 Step-up Transformer

BROWN

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-04100A-04-0527

DIRECT TESTIMONY OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-04100A-04-0527

The direct testimony of Staff witness Crystal S. Brown addresses the following issues:

Background - Southwest Transmission Cooperative, Inc. ("Southwest Transmission" or "Cooperative") is a certificated electric transmission cooperative that supplied transmission service to six Class A members during 2003.

On July 23, 2004, Southwest Transmission filed an application for a permanent rate increase. The primary reason stated by the Cooperative for the rate increase is the anticipated loss of approximately $2.8 million in revenues due to Morenci Water and Electric's ("MW&E) planned bypass of Southwest Transmission's system.

Southwest Transmission's application, as filed, proposes a $3,666,668, or 13.16 percent, revenue increase from $27,855,318 to $31,521,986 [including the temporary Regulatory Asset Charge ("RAC") authorized in Decision No. 62758]. The proposed revenue increase would produce an operating margin of $5,891,477 for a 7.42 percent rate of return on an original cost rate base of $79,392,886. Southwest Transmission requests a 1.15 times interest earned ratio ("TIER").

Revenue Requirement – Staff recommends operating revenues of no less than that proposed by the Cooperative. Staff's recommended revenue would produce a $3,666,668, or 14.58 percent, revenue increase from Staff adjusted Test Year revenues of $25,148,196 to $28,814,864. Staff's recommended revenue (excluding normalized annual RAC collections of $2,559,926) would produce an operating margin of $3,439,610 for a 4.51 percent rate of return on a Staff adjusted original cost rate base of $76,345,655. Staff's recommended revenue provides a 0.65 times interest earned ratio ("TIER") and a 0.81 debt service coverage ratio ("DSC"). Including the RAC, the TIER and DSC improve to 1.13 and 1.02, respectively.

Test Year Operating Margin – Staff made five (5) adjustments that reduced the operating margin by $2,451,867 from $2,224,809 to ($227,058). Staff's adjustments included reclassification and normalization of a Regulatory Asset Charge, normalization of legal and employee expenses and removal of costs unrelated to the provision of utility service.

Rate Base – Staff made six (6) adjustments that reduced rate base by $3,047,230 from $79,392,885 to $76,345,655. Staff's adjustments included removal of working capital, plant held for future use, member advances, deferred debits, acquisition costs and retirement work in progress.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Business Administration from the University of Arizona and a Bachelor of Science Degree in Accounting from Arizona State University.

Since joining the Commission, I have participated in numerous rate cases and other regulatory proceedings involving large electric, gas, telecommunications, and water utilities. I have testified on matters involving regulatory accounting and auditing. During the past six years, I have attended utility-related seminars on regulation, accounting, finance and income taxes designed to provide continuing and updated education in these areas. Various professional and industry organizations sponsored these seminars.

I have been employed by the Commission as a regulatory auditor and a rate analyst since August 1996. Prior to joining the Commission, I was employed by the Department of Revenue as a Senior Internal Auditor and by the Office of the Auditor General as a Financial Auditor. I was a Cost Center Review Specialist for Blue Cross Blue Shield of Arizona prior to my employment in state government.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating income, and revenue requirement regarding Southwest Transmission Cooperative, Inc.'s ("Southwest Transmission" or "Cooperative") application for a permanent rate increase. Staff witness Alejandro Ramirez is presenting Staff's times interest earned ratio ("TIER") and debt service coverage ("DSC") ratio analysis and recommendations. Staff witness Erin Casper is presenting Staff's recommendations regarding the rate design. Staff witness Jerry Smith is presenting Staff's engineering analysis and recommendations.

Q. What is the basis of your recommendations?

A. I performed a regulatory audit of Southwest Transmission's application to determine whether sufficient, relevant, and reliable evidence exists to support the Company's requested rate increase. The regulatory audit consisted of examining and testing the financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission adopted National Rural Utilities Service ("RUS") Uniform System of Accounts ("USOA").

BACKGROUND

Q. Please review the background of this application.

A. Southwest Transmission was formed as a result of the restructuring of Arizona Electric Cooperative, Inc. ("AEPCO"). Prior to August 2001, AEPCO provided both generation and transmission services to its customers. Pursuant to Decision No. 59943, dated December 26, 1996, the Commission approved a phased-in transition to electric competition. In 2001, AEPCO received Commission approval to restructure into three separate affiliated cooperatives: AEPCO, Southwest Transmission, and Sierra Southwest Cooperative ("Sierra Southwest").

AEPCO became a generation cooperative. Southwest Transmission became a transmission cooperative. Sierra Southwest became a cooperative that provides wholesale marketing and support services, including staffing of non-core positions to AEPCO and Southwest Transmission.

Decision No. 63868 required that the Cooperatives provide the Director of the Utilities Division with "an informational submission" that was required within "35 months of the date of closing"[1] for the restructuring. Decision No. 65367, dated November 5, 2002, modified this requirement to include full Arizona Administrative Code R14-2-103 information and set the rate filing date at July 1, 2004. On July 23, 2004, Southwest Transmission filed an application for a permanent rate increase. On August 27, 2004, Staff filed a Letter of Sufficiency.

Southwest Transmission is a certificated Arizona-based transmission cooperative that provided electric transmission service to six Class A members as well as certain other

[1] Decision No. 63868, Page 14, Finding of Fact No. 74

customers during the Test Year. Southwest's current rates were authorized in Decision No. 65367, dated November 5, 2002 and Decision No. 62758, dated July 27, 2000. Decision No. 65367 authorized total revenues of $29,129,952 to provide a 7.99 percent rate of return on a $65,856,223 original cost rate base. Decision No. 62758 authorized the transfer of the Regulatory Asset Charge ("RAC") from AEPCO to Southwest Transmission.

Q. What is the primary reason for the Cooperative's requested permanent rate increase?

A. The primary reason indicated by the Cooperative for the rate increase is the anticipated loss of approximately $2.8 million in revenues due to Morenci Water and Electric's ("MW&E") planned bypass of Southwest Transmission's system.

CONSUMER SERVICE

Q. Please provide a brief history of customer complaints received by the Commission regarding Southwest Transmission.

A. Staff reviewed the Commission's records and found no formal complaints from its members from 2001 to 2004. Five opinions against the rate increase have been received from retail customers of the distribution member cooperative in Mohave County as of February 8, 2005.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Company's filing.

A. The Cooperative's application, as filed, proposes total annual operating revenue of $31,521,986, an increase of $3,666,668, or 13.16[2] percent, over claimed Test Year

[2] The Cooperative's Schedule A-1, line 10 reports a 13.70 percent increase; however, mathematically, $3,666,668 divided by $27,855,318 is 13.16 percent.

revenue of $27,855,318. Southwest Transmission's operating revenues include $2,707,122 of RAC revenues.

Q. **Please summarize Staff's recommended revenue.**

Staff recommends total annual operating revenue of $28,814,864, an increase of $3,666,668, or 14.58 percent, over Staff adjusted Test Year revenues of $25,148,196. Staff recognizes $2,559,926 of non-operating RAC cash flow.

Staff recommends operating revenue no less than that proposed by the Cooperative which (excluding normalized RAC collections of $2,559,926) would produce an operating margin of $3,439,610 for a 4.51 percent rate of return rate return on a Staff adjusted original cost rate base of $76,345,655 to provide a 0.65 times interest earned ratio ("TIER") and a 0.81 debt service coverage ratio ("DSC"). Including the RAC, the TIER and DSC improve to 1.13 and 1.02, respectively.

Q. **What Test Year did Southwest Transmission use in this filing?**

A. Southwest Transmission's rate filing is based on the twelve months ended December 31, 2003 ("Test Year").

Q. **Please summarize the rate base and operating income recommendations and adjustments addressed in your testimony for Southwest Transmission.**

A. My testimony addresses the following issues:

<u>Plant Acquisition Adjustment</u> – This adjustment decreases Plant in Service by $4,413 to properly reflect the original cost rate base and to be consistent with Decision No. 65367.

Accumulated Depreciation – This adjustment increases Accumulated Depreciation by $25,756 to remove retirement work in progress.

Member Advances – This adjustment decreases rate base by $228,188. This adjustment recognizes that the interest paid to the Members is recovered through operating expense, and consequently, the advances which are directly related to the interest expense should be removed from rate base to prevent double recovery.

Working Capital – This adjustment decreases Working Capital by $2,265,954 to reflect Staff's different calculation of certain Working Capital components and to eliminate the Cooperative's selective recognition of components.

Plant Held for Future Use – This adjustment decreases rate base by $377,214 to reflect land that will be liquidated.

Deferred Debit – This adjustment decreases rate base by $145,705 to remove items that are not generally included in rate base.

Regulatory Asset Charge ("RAC") Revenue – This adjustment decreases operating margin by $2,707,122 and increases non-operating revenue by $2,559,926. This adjustment recognizes that RAC collections will cease once the deferred asset has been fully amortized. This adjustment also normalizes the revenues expected from the RAC.

Normalized Legal Expense – This adjustment decreases operating expenses by $83,799 to remove legal expenses that provided no benefit to Members.

<u>Employee Vacancy Level Normalization Adjustment</u> – This adjustment decreases operating expenses by $113,684 to normalize the level of employee vacancies.

<u>Food and Other Expense</u> – This adjustment decreases operating expenses by $57,773 to remove expenses that were not needed to provide safe and reliable service.

<u>Interest Expense on Long-term Debt</u> – This adjustment decreases net margin by $133,675 to reflect Staff's recommended interest on long-term debt.

RATE BASE

Fair Value Rate Base

Q. Did the Company prepare a Schedule showing the elements of Reconstruction Cost New Rate Base ("RCND")?

A. No, the Company did not. Therefore, Staff evaluated the original cost rate base as the fair value rate base ("FVRB").

Rate Base Summary

Q. Please summarize Staff's adjustments to Southwest Transmission's rate base shown on Schedules CSB-2.

A. Staff's adjustments to Southwest Transmission's rate base resulted in a net decrease of $3,047,230, from $79,392,885 to $76,345,655. This decrease was primarily due to reducing the working capital requirement.

Rate Base Adjustment 1 – Plant Acquisition Adjustment

Q. What is Southwest Transmission proposing for its Plant Acquisition Adjustment?

A. Southwest Transmission is proposing $4,413 for the Plant Acquisition Adjustment as shown on Schedule CSB-4.

Q. The $4,413 Plant Acquisition Adjustment is not material to rate base. Why is Staff proposing that it be removed from rate base for rate making purposes?

A. In Decision No. 65367, dated November 5, 2002, Staff recommended that the plant acquisition adjustment be removed because the adjustment was questionable and Staff had not audited the adjustment.[3] The Commission adopted Staff's recommendation to remove Southwest Transmission's acquisition adjustment from rate base (Page 4 at line 23).

Q. Did Staff audit the plant acquisition adjustment in this rate proceeding?

A. Yes, Staff audited the plant acquisition adjustment and found that the Cooperative did not have sufficient documentation to support the adjustment.

Q. Should the plant acquisition adjustment be included in rate base?

A. No, it should not. Original cost rate base is calculated using the original cost of plant assets. An acquisition adjustment, by definition, is not the original cost of an asset because it is the difference between the original cost of an asset and the purchase price. Staff found no sufficient evidence to support the adjustment. Therefore, non-recognition of the acquisition adjustment in rate base is the normal rate-making treatment.

[3] Decision No. 65367, page 4, lines 6 through 9

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $4,413 as shown on Schedules CSB-3 and CSB-4.

Rate Base Adjustment 2 – Accumulated Depreciation

Q. What is Southwest Transmission proposing for Accumulated Depreciation?

A. Southwest Transmission is proposing $54,763,401 for Accumulated Depreciation. That amount is composed of $54,789,157 in accumulated depreciation of plant in service and a $25,756 reduction of accumulated depreciation for a retirement work in progress as shown on Schedule CSB-5.

Q. Is retirement work in progress normally a component of rate base?

A. No. Retirement work in progress should reflect a coordinated treatment of the plant to be retired, accumulated depreciation, salvage value and disposal cost. The retirement should be completed before rate base is adjusted.

In Decision No. 65367[4], dated November 5, 2002, Staff recommended that a retirement work in progress be removed because the amount was questionable and unaudited.[5] The Commission adopted Staff's recommendation. In the instant case, Staff audited the retirement work in progress and determined that it should be removed.

Q. What is Staff recommending?

A. Staff recommends increasing Accumulated Depreciation by $25,756, from $54,763,401 to $54,789,157 to remove retirement work in progress from rate base as shown on Schedules CSB-3 and CSB-5.

[4] Page 24 at line 23
[5] Decision No. 65367, page 4, lines 6 through 9

Rate Base Adjustment 3 – Member Advances

Q. What programs does Southwest Transmission have that result in Member Advances?

A. Southwest Transmission has two types of programs that result in member advances: member investments and member prepaid transmission bills. The member investment program allows members to invest funds with the Cooperative and the Cooperative pays interest on those funds. The prepaid transmission program allows members to make prepayments on their monthly transmission bills and the Cooperative pays interest on those prepaid bills.

Q. How does the Cooperative treat the balance of Member Advances and the interest paid on those funds in its filing?

A. The Cooperative did not deduct Member Advances of $228,188[6] in its rate base calculation but it included the $3,281[7] of interest paid to members for use of their funds as an operating expense. An inequity is created by the Cooperative's proposal because it provides for recovery of Southwest Transmission's Member Advances costs by treating the related interest as an operating expense without also recognizing that AEPCO has use of the fund advanced by members.

Q. What is the effect of the Cooperative's proposed treatment?

A. The effect of the Cooperative's proposed treatment is to provide double recovery. The Cooperative pays interest to the members that provide the advances and recovers that interest cost by including it in operating expenses. Failure to deduct Member Advances overstates rate base by not recognizing the Cooperative's use of the advanced funds and has the effect, theoretically, of providing a return on the advanced funds.

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[6] Per data request response CSB 2-28
[7] Per data request response CSB 6-1

Q. Did the Commission deduct Member Advances in the rate base calculation of the prior rate proceeding in which Southwest Transmission and AEPCO were one cooperative?

A. Yes. The Commission, in Decision No. 58405[8], deducted Member Advances in the rate base calculation.

Q. What is Staff recommending?

A. Consistent with Decision No. 58405, Staff recommends that $228,188 in Member Advances be deducted from rate base as shown on Schedules CSB-3 and CSB-6.

Rate Base Adjustment 4 – Working Capital

Q. What is Southwest Transmission proposing for Working Capital?

A. Southwest Transmission is proposing $3,122,117 for Working Capital. That amount is composed of $858,420 for materials and supplies, $908,046 for prepayments, and $1,355,651 for CFC Certificates and Bonds as shown on Schedule CSB-7.

Q. Did Staff make any adjustments to the Cooperative's Working Capital?

A. Yes. Staff discusses its adjustments to materials and supplies, prepayments, CFC Certificates and Bonds separately.

<u>Working Capital - Materials and Supplies</u>

Q. What amount did Southwest Transmission include for Materials and Supplies in its proposed Working Capital calculation?

A. Southwest Transmission included $858,420 for Materials and Supplies inventory in its working capital calculation.

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[8] Page 6, at line 9

Q. How did Southwest Transmission calculate the Materials and Supplies balance proposed in rate base?

A. Southwest Transmission calculated the Materials and Supplies balance using a 13-month average. This method adds together the December 31, 2002, ending Materials and Supplies balance with the Test Year month-end balances and divides by 13.

Q. Does use of the 13-month average calculation proposed by Southwest Transmission measure the average monthly balance for each month of the Test Year?

A. No. Therefore, the Cooperative's proposed method could over- or under- state the materials and supplies balance.

Q. What method provides a more accurate measurement of the average balance each month?

A. A 12-month average based on the average inventory balance for each month of the Test Year. To illustrate, the average monthly balance for January is calculated by adding the beginning balance on January 1st (i.e., the ending balance on December 31st of prior year) to the ending balance on January 31st, and dividing the total by two. The 12 monthly averages are totaled and divided by 12 to obtain an average balance.

Q. What does Staff recommend for the Materials and Supplies balance in the Working Capital calculation?

A. Staff recommends $856,163 for Materials and Supplies as shown on Schedule CSB-7.

Working Capital - Prepayments, CFC Certificates and Bonds

Q. Is Southwest Transmission proposing to include Prepayments, CFC Certificates and Bonds in the Working Capital calculation?

A. Yes. Southwest Transmission is proposing $908,046 for prepayments and $1,355,651 in CFC Certificates and Bonds.

Q. Does Southwest Transmission's proposal to include Prepayments, CFC Certificates and Bonds in the Working Capital calculation represent an inequitable, selective adjustment to increase rate base?

A. Yes. The Cooperative has ignored the large component of Working Capital (i.e., cash working capital) represented by revenues received and expenses paid. The impact on Working Capital of revenues and expenses can be calculated using a lead-lag study. A lead-lag study is recognized as the most accurate method to calculate cash working capital.

The Cooperative chose not to conduct a lead-lag study, and accordingly, omitted a major component of Working Capital. It is inequitable to ignore a major component of the Working Capital analysis and selectively recognize other components. Had a lead-lag study been conducted, it might have shown that Working Capital is a negative component of rate base.

Q. What factors imply that a lead-lag study could result in Working Capital being a negative component of rate base?

A. Interest and property tax expenses are components of a lead-lag study. The Cooperative has approximately $5 million in interest expense and $2 million in property taxes. The Cooperative collects cash used to make interest and property tax expense payments prior to the dates payment is due. For the period that Southwest Transmission holds these funds before payment, they are a source of cost-free capital. If a lead-lag study were performed, this source of cost-free cash would be a significant negative factor in calculation of the net working capital.

Q. Does the Cooperative receive interest on the CFC Certificates and Bonds?

A. Yes. In response to CSB 2-23, the Cooperative stated that it received approximately $67,782[9]. Therefore, including the CFC certificates and bonds in rate base would provide a second return on these investments.

Q. Did the Commission remove Prepayments and CFC Certificates and Bonds from rate base of the prior rate proceeding in which Southwest Transmission and AEPCO were one cooperative?

A. The Commission removed prepayments in Decision No. 58405[10]. The Cooperative had not included CFC Certificates and Bonds in the rate base of that proceeding, therefore, it was not addressed in Decision No. 58405.

Q. What is Staff recommending for Prepayments and CFC Certificates and Bonds?

A. Consistent with Decision No. 58405, Staff recommends removal of Prepayments. Staff also recommends removal of CFC Certificates and Bonds from Working Capital as shown on Schedules CSB-3 and CSB-7.

Q. What is Staff's recommended adjustment to Working Capital?

A. Staff recommends decreasing Working Capital by $2,265,954 from $3,122,117 to $856,163 as shown on Schedules CSB-3 and CSB-7.

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[9] Per response to CSB 2-23, the $1.355 million Equity Term Certificates accrues interest at 5.00 % annually.
[10] Page 6, at line

Rate Base Adjustment 5 – Plant Held for Future Use

Q. What amount in Plant Held for Future Use is Southwest Transmission proposing to include in rate base?

A. Southwest Transmission is proposing to include $377,214 of land classified as Plant Held for Future Use in rate base.

Q. Does Southwest Transmission have a plan for future use of the land?

A. No, it does not. In response to CSB 2-29, the Cooperative indicated that the land was purchased for a substation site's right-of-ways. The location of the substation changed, the land was no longer needed and will likely be liquidated.

Q. What is Staff recommending?

A. Staff recommends removal of the $377,214 in Plant Held for Future Use from Rate Base as shown on Schedules CSB-3 and CSB-8.

Rate Base Adjustment 6 – Deferred Debit

Q. What amount in Deferred Debits is Southwest Transmission proposing to include in Rate Base?

A. Southwest Transmission is proposing $145,705 for Deferred Debits as shown on Schedule CSB-9. The amount is composed of $193 for preliminary survey and investigation charges, $57,657 for Job Tickets, and $87,855 for unamortized losses on reacquired debt.[11]

[11] Per response to CSB 2-22

Q. Should these Deferred Debits be included in rate base?

A. No, they should not. The Deferred Debits balance consists of items that are not generally included in rate base. Preliminary survey and investigation charges and job tickets are a type of construction work in progress. Construction work in progress by definition is not used and useful.

Unamortized losses on reacquired debt present no future cash requirements for the Cooperative. Since Staff recommends a revenue requirement dependent on cash flow needs, there is no revenue requirement directly related to the carrying balance. Moreover, to the extent that losses on reacquired debt were refinanced with new debt, Staff is recommending recovery of these costs via operating and RAC revenue that provides TIER and DSC ratios exceeding 1.0. Including the unamortized loss on reacquired debt in rate base would be inequitable and serve only as a selective adjustment to augment rate base in the same manner as prepayments, CFC Bonds and Certificates.

Q. Did the Commission remove the deferred debit from the rate base of the prior rate proceeding in which Southwest Transmission and AEPCO were one cooperative?

A. Yes, the Commission, in Decision No. 58405[12], removed the Deferred Debit from rate base.

Q. What is Staff recommending?

A. Consistent with Decision No. 58405, Staff recommends removal of the Deferred Debit from Rate Base as shown on Schedules CSB-3 and CSB-9.

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[12] Page 6, at line 8 ½

OPERATING INCOME

Operating Income Summary

Q. What are the results of Staff's analysis of Test Year revenues, expenses, and operating income?

A. As shown on Schedules CSB-10 and CSB-11, Staff's analysis resulted in Test Year revenues of $25,148,196, expenses of $25,375,254, and operating income before interest expense on long-term debt of ($227,058).

Operating Income Adjustment No. 1 – Regulatory Asset Charge

Q. What is the source and purpose of the regulatory asset charge?

A. In Decision No. 62758, the Commission transferred the regulatory asset charge ("RAC") from AEPCO to Southwest Transmission. The initial purpose of the RAC was to recover deferred debt refinancing costs and costs associated with the buy-out of the Carbon Coal all-requirements contract. The RAC, as authorized by the Commission, is scheduled to decrease each year over the amortization term until the deferred cost is fully recovered.

Q. Did Staff make an adjustment to the revenue generated by regulatory asset charge in the Test Year?

A. Yes, Staff reclassified the RAC collections from operating revenue and recognized it as a separate source of cash flow since it will cease when the regulatory asset is fully recovered. Staff also reduced the amount of RAC revenue from the actual Test Year amount of $2,707,122 to $2,559,926. Staff's lower amount represents a three-year normalization to recognize the known, scheduled decreasing RAC level as shown on Schedule CSB-12.

Q. What is Staff recommending?

A. Staff recommends reducing operating revenue by $2,707,122 and recognizing $2,559,926 of RAC cash flow as shown on Schedules CSB-11 (lines 6 and 32) and CSB-12 (lines 5 and 9).

Operating Income Adjustment No. 2 – Normalized Legal Expense

Q. What is Southwest Transmission proposing for Outside Services, Legal expenses?

A. Southwest Transmission is proposing $316,875[13] for Outside Services, Legal expenses as shown on Schedule CSB-13, line 4. Staff discusses the components of its legal expense normalization adjustment separately.

<u>ACC Jurisdiction Related Legal Expense</u>

Q Does the Cooperative propose to include legal expenses that provide no benefit to ratepayers in its revenue requirement?

A. Yes. Southwest Transmission incurred and requests recovery of legal expenses related to its filing that requested that the Cooperative not be subject to ACC regulation (Decision No. 66835, dated March 12, 2004).

Q. What is Staff recommending?

A. Staff recommends reducing Outside Services, Legal Expense by $77,936 as shown on Schedule CSB-13, line 2 to eliminate the legal expenses related to the ACC jurisdictional filing.

[13] Per data request response to CSB 2-40.

Redacted Minutes and Legal Invoices

Q. Did Southwest Transmission fail to support any of its legal expenses?

A. Yes. Southwest Transmission objected to the release of certain portions of the Minutes of the Executive Session of the Board of Directors and legal invoices citing the attorney-client privilege. Therefore, the appropriateness of the certain legal costs could not be substantiated.

Q. Did Staff inform Southwest Transmission of the likely consequence of not providing the requested information?

A. Yes, in a letter dated September 29, 2004, addressed to both Southwest Transmission and AEPCO, Staff indicated that failure to provide complete legal invoices will result in a disallowance of such costs.

Q. What was the total amount of expenses related to the redacted legal invoices and minutes that Staff recommends to be disallowed?

A. The total amount was $5,863[14] as shown on Schedule CSB-13 line 3.

Q. Did the Commission find it appropriate to disallow legal expenses from AEPCO prior to Southwest Transmission's spinoff?

A. Yes. In AEPCO's prior rate proceeding before Southwest Transmission was spunoff, Staff recommended that $464,000[15] in legal expenses paid to a law firm should be disallowed because it was imprudent for Southwest Transmission to have entered into the fee arrangements with the law firm. The Commission adopted Staff's recommendation.

[14] Staff estimated the majority of expenses related to the redacted issues based upon the number of general groups of issues on an invoice. The total amount billed on the invoice was divided by the number of general groups.
[15] Decision No. 58405, page 12, lines 5-12 and lines 21-23.

Q. Does Southwest Transmission's denial of access to records provide concerns beyond whether these legal costs are related to the provision of utility service and recoverable?

A. Yes. Beyond the issue of whether the legal costs were incurred for utility purposes, the lack of access to records raises a question as to whether other significant issues related to the revenue requirement went undiscovered.

Q. Does Staff have any other recommendations regarding redacted issues?

A. Yes. In this case Staff was unable to quantify and remove payroll costs of all employees, outside services staff, and members of the Board of Directors who spent time working on the redacted issues. Staff recommends that in future rate proceedings Southwest Transmission be required to quantify all payroll costs of employees, outside services staff, and members of the Board of Directors fees related to time spent on redacted issues.

Operating Income Adjustment No. 3 – Employee Vacancy Level

Q. What is an employee vacancy level?

A. An employee vacancy level reflects the number of employee positions that are not occupied.

Q. What were the Cooperative's vacancy levels for the years 2001, 2002, and 2003?

A. The Cooperative's vacancy levels for the years 2001, 2002, and 2003 were 5, 3, and 1[16], respectively, as shown on Schedule CSB-14.

[16] Per data request response to CSB 2-37

Q. What is an appropriate way to recognize the year-to-year variances in the employee vacancy rate and associated costs to provide an average level of costs?

A. The employee vacancy rate can be normalized by recognizing the average vacancy rate. Staff averaged the employee vacancy rates for the years 2001, 2002 and 2003 to calculate a normalized vacancy rate. Then, Staff calculated the difference between the Test Year rate and the normalized rate and multiplied that difference by the average salary level for those years to determine an adjustment to reflect salaries at the normalized levels. This calculation is shown on Schedule CSB-14.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $113,684 as shown on Schedules CSB-11 and CSB-14.

Operating Income Adjustment No. 4 – Food and Other Expenses

Q. What is Southwest Transmission proposing for food, entertainment, and similar expenses?

A. Southwest Transmission is proposing $57,773 for food, entertainment, and similar expenses as shown on Schedule CSB-15.

Q. Are these expenses necessary for the provision of safe and reliable service?

A. No, these costs are not necessary for the provision of safe and reliable service.

Q. What ratemaking treatment does Staff recommend for these types of expenses?

A. Since these costs are not necessary to provide service, Staff recommends that they be recognized as non-operating expenses and excluded from the revenue requirement.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $57,773 as shown on Schedules CSB-11 and CSB-15.

Non-Operating Income Adjustment No. 5 – Interest Expense on Long-term Debt

Q. What is the Cooperative proposing for Interest Expense on Long-term Debt?

A. Southwest Transmission is proposing $5,168,413 for Interest Expense on Long-term Debt as shown on Schedule CSB-16.

Q. Did Staff accept the proposed Interest Expense on Long-term Debt amount?

A. No, Staff did not. As discussed in the testimony of Staff Witness, Alejandro Ramirez, Staff determined that the appropriate amount of interest expense on long-term debt is $5,302,088.

Q. What is Staff recommending?

A. Staff recommends increasing the Interest Expense on Long-term Debt by $133,675 as shown on Schedules CSB-11 and CSB-16.

Arizona Corporation Commission Gross Revenue Assessment

Q. What came to Staff's attention during the course of the audit concerning the ACC assessment?

A. Southwest Transmission's application did not report collecting any amount for an ACC assessment. This is consistent with the Cooperative's annual report filed with the Commission for the year 2003. The Commission did not assess the Cooperative because the Cooperative reported $0 for intra-state revenues in its 2003 utilities annual report. In a letter addressed to the Utilities Division Compliance section, dated December 10, 2004, Southwest Transmission stated, "SWTransco did not pay any annual assessment amounts in 2003 pursuant to A.R.S. §40-401 because it did not have any "gross operating revenues derived from intrastate operations during the preceding calendar year."

Q. Is Staff currently investigating this matter?

A. Yes.

Q. What does Staff recommend pending the outcome of this investigation?

A. If the Commission determines that Southwest Transmission should be assessed, Staff recommends that the assessment be flowed through similar to sales taxes. This flow-through was authorized by the Commission in Decision No. 58405, prior to the restructuring of Southwest Transmission and AEPCO. On footnote 9, page 17, of that decision, the Commission states that "The gross revenue tax will in the future be recovered through a bill add-on." Therefore, the assessment should not be included in the cost of service.

Jurisdictional Separation

Q. Did Southwest Transmission maintain separation between Commission jurisdiction and non-jurisdiction revenues and expenses ?

A. No, it did not. The Cooperative serves a California member for which separate revenues and expenses were not maintained.

Q. Is the Cooperative required to maintain separation of the revenues and expenses for the California member?

A. Yes. The Arizona Administrative Code R14-2-103 B4 states the following:

> Separation of nonjurisdictional properties, revenues and expenses associated with the rendition of utility service not subject to the jurisdiction of the Commission must be identified and properly segregated in a recognized manner when appropriate.

Q. Can Staff identify some cooperatives that provided jurisdictionally separated information in their rate filings?

A. Yes. Duncan Valley Electric Cooperative, Inc. and Garkane Power Association, Inc. provide jurisdictionally separated information in compliance with the Administrative Code. These cooperatives generate much smaller revenues than Southwest Transmission. The jurisdictionally separated financial information helps to verify that Arizona ratepayers are not paying more than their fair share of the cost of providing service.

Q. What is Staff recommending?

A. Staff recommends that the Cooperative comply with Arizona Administrative Code R14-2-103(B)(4) in its next rate filing.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL COST With RAC	[B] COMPANY ORIGINAL COST Without RAC	[C] STAFF ORIGINAL COST With RAC	[D] STAFF ORIGINAL COST Without RAC
1	Adjusted Operating Income (Loss)	$ 2,224,809	$ (482,313)	$ (227,058)	$ (227,058)
2	Depreciation and Amortization	$ 6,852,107	$ 6,852,107	$ 6,852,107	$ 6,852,107
3	Income Tax Expense	-	-	-	-
4	Interest Expense on Long-term Debt	$ 5,168,413	$ 5,168,413	$ 5,302,088	$ 5,302,088
5	Principal Repayment	$ 6,349,686	$ 6,349,686	$ 7,358,610	$ 7,358,610
6	**Recommended Increase in Operating Revenue**	$ 3,666,668	$ 3,666,668	$ 3,666,668	**$ 3,666,668**
7	Percent Increase (Line 6 / Line 10)	13.16%	14.58%	14.58%	**14.58%**
8	Network Service and Other Revenue	$ 25,148,196	$ 25,148,196	$ 25,148,196	$ 25,148,196
9	Regulatory Asset Charge ("RAC")[1]	$ 2,707,122	$ -	$ -	$ -
10	Adjusted Test Year Operating Revenue	$ 27,855,318	$ 25,148,196	$ 25,148,196	$ 25,148,196
11	**Total Annual Operating Revenue**	$ 31,521,986	$ 28,814,864	$ 28,814,864	**$ 28,814,864**
12	**Operating Margin**	$ 5,891,477	$ 3,184,355	$ 3,439,610	**$ 3,439,610**
13	Net Margin	$ 771,906	$ (1,935,216)	$ 746,290	$ 746,290
14	Normalized RAC Revenue, Non-operating	N/A	N/A	$ 2,559,926	$ -
15	Total Operating Revenue and RAC Revenue			$ 5,999,536	$ 3,439,610
16	Cooperative Net TIER (L4+L13) / L4	1.15	0.63	N/A	N/A
17	**Staff Operating TIER (L3+L12+L14) / L4**	N/A	N/A	1.13	**0.65**
18	Cooperative DSC (L2+L4+L13)/(L4+L5)	1.11	0.88	N/A	N/A
19	**Staff DSC (L2+L3+L12+L14)/(L4+L5)**	N/A	N/A	1.02	**0.81**
20	**Adjusted Rate Base**	$ 79,392,885	$ 79,392,885	$ 76,345,655	**$ 76,345,655**
21	Rate of Return (L12 / L20)	7.42%	4.01%	4.51%	4.51%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [D]: Staff Schedules CSB-2, CSB-10, Testimony Alejandro Ramirez

(1) Southwest Transmission classified Regulatory Asset Charge as Operating Revenue.
Accordingly, Staff's recommended Operating Revenue is not comparable to the SWT's.

RATE BASE - ORIGINAL COST

LINE NO.		(A) COMPANY AS FILED	(B) STAFF ADJUSTMENTS	REF	(C) STAFF AS ADJUSTED
1	Plant in Service	$131,520,683	$ (4,413)		$ 131,516,270
2	Less: Accumulated Depreciation	(55,772,833)	(25,756)		(55,798,589)
3	Net Plant in Service	$ 75,747,850	$ (30,169)		$ 75,717,681
	LESS:				
4	Advances in Aid of Construction (AIAC)	$ -	$ -		$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -		$ -
6	Less: Accumulated Amortization	-	-		-
7	Net CIAC	-	-		-
8	Total Advances and Contributions	$ -	$ -		$ -
9	Member Advances	$ -	$ (228,188)		$ (228,188)
	ADD:				
10	Working Capital	$ 3,122,116	$ (2,265,954)		$ 856,162
11	Plant Held for Future Use	$ 377,214	$ (377,214)		$ -
12	Deferred Debits	$ 145,705	$ (145,705)		$ -
13	**Total Rate Base**	$ 79,392,885	$ (3,047,230)		$ 76,345,655

References:
Column [A], Company Schedule B-1, Page 1;
Column [B]: Schedule CSB-4
Column [C]: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-3

SUMMARY OF RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] Plant Acquisition Adjustment ADJ No. 1	[C] Accumulated Depreciation ADJ No. 2	[D] Member Advances ADJ No. 3	[E] Working Capital ADJ No. 4	[F] Plant Held For Future Use ADJ No. 5	[G] Deferred Debits ADJ No. 6	[H] STAFF ADJUSTED
	PLANT IN SERVICE:								
1	Intangible Plant	$ 2,160,171	$ (4,413)	$ -	$ -	$ -	$ -	$ -	$ 2,155,758
2	Transmission Plant - Structures & Improvements	4,139,476	-	-	-	-	-	-	4,139,476
3	Transmission Plant - Station Equipment	44,271,948	-	-	-	-	-	-	44,271,948
4	Transmission Plant - Towers & Fixtures	8,220,075	-	-	-	-	-	-	8,220,075
5	Transmission Plant - Poles & Fixtures	23,837,071	-	-	-	-	-	-	23,837,071
6	Transmission Plant - Overhead Conductors	15,874,087	-	-	-	-	-	-	15,874,087
7	Transmission Plant - All Other Plant	1,783,828 [1]	-	-	-	-	-	-	1,783,828
8	General Plant - Transportation Equipment	1,253,412	-	-	-	-	-	-	1,253,412
9	General Plant - Power Operated Equipment	2,207,359	-	-	-	-	-	-	2,207,359
10	General Plant - Communication Equipment	12,219,399	-	-	-	-	-	-	12,219,399
11	General Plant - All Other Plant	899,545 [2]	-	-	-	-	-	-	899,545
12	Completed Construction - Unclassified	604,312	-	-	-	-	-	-	604,312
13	Total Plant in Service - Actual	117,470,683	(4,413)	-	-	-	-	-	$ 117,466,270
14	Pro-forma Adjustment, Trans Plant - Station Equip	5,084,058	-	-	-	-	-	-	$ 5,084,058
15	Pro-forma Adjustment, Trans Plant - Towers & Fix	8,457,902	-	-	-	-	-	-	8,457,902
16	Pro-forma Adjustment, Communication Equipment	508,040	-	-	-	-	-	-	508,040
17	Total Plant in Service - Pro-forma	14,050,000	-	-	-	-	-	-	$ 14,050,000
18	Total Plant in Service - Actual and Proforma	$ 131,520,683	$ (4,413)	$ -	$ -	$ -	$ -	$ -	$ 131,516,270
19	Less: Accumulated Depreciation - Actual	$ (54,763,401)	$ -	$ (25,756)	$ -	$ -	$ -	$ -	$ (54,789,157)
20	Less: Accumulated Amortization - Actual	(1,009,432)	-	-	-	-	-	-	(1,009,432)
21	Total Accumulated Depreciation & Amortization	$ (55,772,833)	$ -	$ (25,756)	$ -	$ -	$ -	$ -	$ (55,798,589)
22	Net Plant in Service	$ 75,747,850	$ (4,413)	$ (25,756)	$ -	$ -	$ -	$ -	$ 75,717,681
	LESS:								
23	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Contributions in Aid of Construction (CIAC)	$ -	-	-	-	-	-	-	$ -
25	Less: Accumulated Amortization	-	-	-	-	-	-	-	-
26	Net CIAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Advances and Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Member Advances	$ -	$ -	$ -	$ (228,188)	$ -	$ -	$ -	$ (228,188)
	ADD:								
29	Working Capital Allowance	$ 3,122,116	$ -	$ -	$ -	$ (2,265,954)	$ -	$ -	$ 856,162
30	Plant Held For Future Use	377,214	-	-	-	-	(377,214)	-	-
31	Deferred Debits	145,705	-	-	-	-	-	(145,705)	-
32	**Total Rate Base**	$ 79,392,885	$ (4,413)	$ (25,756)	$ (228,188)	$ (2,265,954)	$ (377,214)	$ (145,705)	$ 76,345,655

Footnote Explanations
[1] Includes account nos. 350 and 359
[2] Includes account nos. 389,390,393,394,395,398, & 399

ADJ No.		References:
1	Plant Acquisition Adj	Schedule CSB-4
2	Accumulated Deprec	Schedule CSB-5
3	Member Advances	Schedule CSB-6
4	Working Capital	Schedule CSB-7
5	Plant Held for Future Use	Schedule CSB-8
6	Deferred Debits	Schedule CSB-9

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-4

RATE BASE ADJUSTMENT NO. 1 - ACQUISITION ADJUSTMENT

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED (Sch E-5)	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Intangible Plant (Excluding Acquisition Adj)	$ 2,155,758	$ -	$ 2,155,758
2	Intangible Plant, Acquisition Adjustment	$ 4,413	$ (4,413)	$ -
	Total Intangible Plant	**$ 2,160,171**	**$ (4,413)**	**$ 2,155,758**

3 To remove unauthorized acquistion adjustment from plant in service.

4 References:
5 Column [A]: Cooperative Schedule E-5, Page 1
6 Column [B]: Testimony, CSB
7 Column [C]: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-5

RATE BASE ADJUSTMENT NO. 2 - ACCUMULATED DEPRECIATION

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Accumulated Depreciation	$ (54,789,157)	$ -	$ (54,789,157)
2	Accumulated Depr, Retirement Work In Progress	$ 25,756	$ (25,756)	$ -
3	**Total Accumulated Depreciation** (Line 1+Line 2)	**$ (54,763,401)**	**$ (25,756)**	**$ (54,789,157)**

References:

Column A: Cooperative Schedules B-2, Page 1

Column B: Testimony, CSB, Company Data Request Responses CSB 3-18 and CSB 3-19

Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-6

RATE BASE ADJUSTMENT NO. 3 - MEMBER ADVANCES

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Member Advances	$ -	$ (228,188)	$ (228,188)
2				
3				
4				
5		Ending Balance		
6		(Per CSB 2-28)		Average Balance
7	Dec-02	$ 56,105.00		
8	Jan-03	$ (56,105.00)		$ -
9	Feb-03	$ (470,000.00)		$ (263,052.50)
10	Mar-03	$ (578,615.00)		$ (524,307.50)
11	Apr-03	$ (146,720.00)		$ (362,667.50)
12	May-03	$ (115,079.00)		$ (130,899.50)
13	Jun-03	$ (82,308.00)		$ (98,693.50)
14	Jul-03	$ (199,185.00)		$ (140,746.50)
15	Aug-03	$ (225,000.00)		$ (212,092.50)
16	Sep-03	$ (277,487.00)		$ (251,243.50)
17	Oct-03	$ (245,312.00)		$ (261,399.50)
18	Nov-03	$ (214,362.00)		$ (229,837.00)
19	Dec-03	$ (184,193.00)		$ (199,277.50)
20		$ (2,738,261.00)		$ (2,674,217.00)
21				/ 12
22				$ (228,188.42)

References:

Column [A]: Cooperative Schedule B-5, Page 1 and 3
Column [B]: Column C - Column A
Column [C]: Example calculation: Jan-03 = (Dec-02 + Jan-03) / 2; CSB 1-21

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-7

RATE BASE ADJUSTMENT NO. 4 - WORKING CAPITAL

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Cash Working Capital	$ -	$ -	$ -
2	Materials and Supplies	$ 858,420	$ (2,257)	$ 856,163
3	Prepayments	$ 908,046	$ (908,046)	$ -
4	CFC Certificates and Bonds	$ 1,355,651	$ (1,355,651)	$ -
5	**Total Working Capital**	**$ 3,122,117**	**$ (2,265,954)**	**$ 856,163**

6 References:

7 Column A: Cooperative Schedule E-5, Page 1

8 Column B: Testimony, CSB, Company Data Request Responses CSB 2-9

9 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-7.1

MATERIALS AND SUPPLIES BALANCE CALCULATION

LINE NO.	END OF MONTH BALANCE	[A] COMPANY AS FILED 13-Month Avg	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED 12-Month Avg
1	Dec-02	$ 839,883	$ (839,883)	$ -
2	Jan-03	$ 845,237	$ (2,677)	$ 842,560
3	Feb-03	$ 845,435	$ (99)	$ 845,336
4	Mar-03	$ 860,498	$ (7,532)	$ 852,967
5	Apr-03	$ 849,761	$ 5,369	$ 855,130
6	May-03	$ 844,738	$ 2,512	$ 847,250
7	Jun-03	$ 845,081	$ (172)	$ 844,910
8	Jul-03	$ 861,774	$ (8,347)	$ 853,428
9	Aug-03	$ 866,317	$ (2,272)	$ 864,046
10	Sep-03	$ 864,534	$ 892	$ 865,426
11	Oct-03	$ 852,361	$ 6,087	$ 858,448
12	Nov-03	$ 852,730	$ (185)	$ 852,546
13	Dec-03	$ 931,106	$ (39,188)	$ 891,918
14		$ 11,159,455	$ (885,495)	$ 10,273,961
15	Divided by	13		12
16		$ 858,420	$ (2,257)	$ 856,163

17 References:
18 Column [A]: Cooperative Schedule B-5, Pages 1 and 3
19 Column [B]: Testimony, CSB; Column C - Column A
20 Column [C]: Example calculation: Jan-03 = (Dec-02 + Jan-03) / 2

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-8

RATE BASE ADJUSTMENT NO. 5 - PLANT HELD FOR FUTURE USE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	**Plant Held For Future Use**	**$ 377,214**	**$ (377,214)**	**$ -**

2 References:

3 Column A: Cooperative Data Request Response CSB 2-29
4 Column B: Testimony, CSB
5 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-9

RATE BASE ADJUSTMENT NO. 6 - DEFERRED DEBITS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (CSB 3-1)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Preliminary Survey & Investigation Charges	$ 193	$ (193)	$ -
2	Job Tickets	$ 57,657	$ (57,657)	$ -
3	Unamortized Losses on Reacquired Debt	$ 87,855	$ (87,855)	$ -
4	Total Deferred Debits	**$ 145,705**	**$ (145,705)**	**$ -**

5 References:
6 Column [A]: Cooperative Schedule B-1, CSB 2-22
7 Column [B]: Testimony, CSB
8 Column [C]: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-10

OPERATING INCOME - TEST YEAR AND STAFF PROPOSED

LINE NO.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED
1	*REVENUES:*					
2	Network Transmission Serv & Other Revenue	$ 25,148,196	$ -	$ 25,148,196	$ 3,666,668	$ 28,814,864
3	Regulatory Asset Charge	2,707,122	(2,707,122)	-	-	-
4	Total Electric Transmission Revenue	$ 27,855,318	$ (2,707,122)	$ 25,148,196	$ 3,666,668	$ 28,814,864
5	*EXPENSES:*					
6	Energy	$ 2,541,334	$ -	$ 2,541,334	$ -	$ 2,541,334
7	Transmission	$ 7,649,597	$ (113,684)	$ 7,535,913	-	7,535,913
8	Administrative and General	$ 3,872,157	$ (141,571)	$ 3,730,586	-	3,730,586
9	Maintenance	$ 2,429,390	$ -	$ 2,429,390	-	2,429,390
10	Maintenance - General Plant	$ 79	$ -	$ 79	-	79
11	Depreciation and Amortization	$ 6,852,107	$ -	$ 6,852,107	-	6,852,107
12	ACC Gross Revenue Taxes	$ -	$ -	$ -	-	-
13	Property Taxes	$ 2,285,845	$ -	$ 2,285,845	-	2,285,845
14	Income Taxes	$ -	$ -	$ -	-	-
15	**Total Operating Expenses**	$ 25,630,509	$ (255,255)	$ 25,375,254	$ -	$ 25,375,254
16	**Operating Margin Before Interest on L.T.- Debt**	$ 2,224,809	$ (2,451,867)	$ (227,058)	$ 3,666,668	$ 3,439,610
17	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
18	Interest on Long-term Debt	$ 5,168,413	$ 133,675	$ 5,302,088	$ -	$ 5,302,088
19	Other Interest & Other Dedcutions	232,030	-	232,030	-	232,030
20	**Total Interest & Other Deductions**	$ 5,400,443	$ 133,675	$ 5,534,118	$ -	$ 5,534,118
21	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (3,175,634)	$ (2,585,542)	$ (5,761,176)	$ 3,666,668	$ (2,094,508)
22	***NON-OPERATING MARGINS***					
23	Interest Income	$ 172,901	$ -	$ 172,901	$ -	$ 172,901
24	Other Non-operating Income	107,971	-	$ 107,971	$ -	$ 107,971
25	**Total Non-Operating Margins**	$ 280,872	$ -	$ 280,872	$ -	$ 280,872
26	***REGULATORY ASSET CHARGE***	$ -	$ 2,559,926	$ 2,559,926	$ -	$ 2,559,926
27	***NET MARGINS (LOSS)***	$ (2,894,762)	$ (25,616)	$ (2,920,378)	$ 3,666,668	$ 746,290

25 References:
26 Column (A): Company Schedule C-1, Page 2
27 Column (B): Schedule CSB-9
28 Column (C): Column (A) + Column (B)
29 Column (D): Schedules CSB-1 and CSB-2
30 Column (E): Column (C) + Column (D)

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-11

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1 Regulatory Asset Charge Revenue	[C] ADJ #2 Normalized Legal Expense	[D] ADJ #3 Employee Vacancy Level Normalization	[E] ADJ #4 Food & Other Expenses	[F] ADJ #5 Interest on Long Term Debt	[G] STAFF ADJUSTED
			Ref: Sch CSB-12	Ref: Sch CSB-13	Ref: Sch CSB-14	Ref: Sch CSB-15	Ref: Sch CSB-16	
	REVENUES:							
1	Network Transmission Service	$ 13,104,192	$ -	$ -	$ -	$ -	$ -	$ 13,104,192
2	Point to Point	7,617,540	-	-	-	-	-	7,617,540
3	Total Electric Revenue	$ 20,721,732	$ -	$ -	$ -	$ -	$ -	$ 20,721,732
4	Load Dispatch and System Control	$ 2,824,224	$ -	$ -	$ -	$ -	$ -	$ 2,824,224
5	Direct Access Facilities	515,580	-	-	-	-	-	515,580
6	Regulatory Asset Charge	2,707,122	(2,707,122)	-	-	-	-	-
7	Other Operating Revenue	413,318	-	-	-	-	-	413,318
8	Ancilliary Services From AEPCO	-	-	-	-	-	-	-
9	Special Contracts	673,342	-	-	-	-	-	673,342
10	**Total Revenues**	$ 27,855,318	$ (2,707,122)	$ -	$ -	$ -	$ -	$ 25,148,196
	OPERATING EXPENSES:							
11	Energy	$ 2,541,334	$ -	$ -	$ -	$ -	$ -	$ 2,541,334
12	Transmission	7,649,597	-	-	(113,684)	-	-	7,535,913
13	Administrative and General	3,872,157	-	(83,799)	-	(57,773)	-	3,730,586
14	Maintenance	2,429,390	-	-	-	-	-	2,429,390
15	Maintenance - General Plant	79	-	-	-	-	-	79
16	Depreciation and Amortization	6,852,107	-	-	-	-	-	6,852,107
17	ACC Gross Revenue Taxes	-	-	-	-	-	-	-
18	Other Taxes	2,285,845	-	-	-	-	-	2,285,845
19	Income Taxes	-	-	-	-	-	-	-
20	**Total Operating Expenses**	$ 25,630,509	$ -	$ (83,799)	$ (113,684)	$ (57,773)	$ -	$ 25,375,254
21	**Operating Margin Before Interest on L.T.- Debt**	$ 2,224,809	$ (2,707,122)	$ 83,799	$ 113,684	$ 57,773	$ -	$ (227,058)
23	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***							
24	Interest on Long-term Debt	$ 5,168,413	$ -	$ -	$ -	$ -	$ 133,675	$ 5,302,088
25	Other Interest & Other Dedcutions	232,030	-	-	-	-	-	232,030
26	**Total Interest & Other Deductions**	$ 5,400,443	$ -	$ -	$ -	$ -	$ 133,675	$ 5,534,118
27	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (3,175,634)	$ (2,707,122)	$ 83,799	$ 113,684	$ 57,773	$ (133,675)	$ (5,761,176)
28	***NON-OPERATING MARGINS***							
29	Interest Income	$ 172,901	$ -	$ -	$ -	$ -	$ -	$ 172,901
30	Other Non-operating Income	107,971	-	-	-	-	-	107,971
31	**Total Non-Operating Margins**	$ 280,872	$ -	$ -	$ -	$ -	$ -	$ 280,872
32	***REGULATORY ASSET CHARGE***	$ -	$ 2,559,926	$ -	$ -	$ -	$ -	$ 2,559,926
33	***NET MARGINS (LOSS)***	$ (2,894,762)	$ (147,196)	$ 83,799	$ 113,684	$ 57,773	$ (133,675)	$ (2,920,378)

Southwest Transmission Cooperative, Inc. Schedule CSB-12
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

OPERATING INCOME ADJUSTMENT NO. 1 - REGULATORY ASSET CHARGE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Revenue	$ 25,148,196	$ -	$ 25,148,196
2	Regulatory Asset Charge	$ 2,707,122	$ (2,707,122)	$ -
3	Total Revenue	$ 27,855,318	$ (2,707,122)	$ 25,148,196
4	Expense	$ 25,630,509	$ -	$ 25,630,509
5	Operating Margin Before Interest	$ 2,224,809	$ (2,707,122)	$ (482,313)
6	Total Interest	$ 5,400,423	$ -	$ 5,400,423
7	Margins After Interest Expense	$ (3,175,614)	$ (2,707,122)	$ (5,882,736)
8	Non-Operating Margins	$ 280,872		$ 280,872
9	Normalized Regulatory Asset Charge Rev	$ -	$ 2,559,926	$ 2,559,926
10	Net Margin	$ (2,894,742)	$ (147,196)	$ (3,041,938)

CALCULATION OF NORMALIZED REGULATORY ASSET CHARGE

	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
11		Total kWhs		Total kWhs
12	Anza	44,660,813	-	44,660,813
13	Duncan	26,782,590	-	26,782,590
14	Graham	136,552,300	-	136,552,300
15	Mohave 1	611,433,890	-	611,433,890
16	Sulphur	662,992,990	-	662,992,990
17	TRICO (See Note Below)	437,521,797	-	437,521,797
18		1,919,944,380		1,919,944,380
19	Regulatory Asset Charge	$ 0.00141	$ (0.00008)	$ 0.00133
20	**Regulatory Asset Charge (L8 x L9)**	$ 2,707,122	(147,196)	$ 2,559,926

21			RAC
22			Decision No.62758
23		2004 RAC	$ 0.00137
24		2005 RAC	$ 0.00133
25	**Note:**	2006 RAC	$ 0.00130
26	The Cooperative filed 437,520,942 kWhs.		$ 0.00400
27	Staff used the Cooperative's actual kWhs	Divided by	3
28	of 437,521,797 to reconcile to the $2,707,122		$ 0.00133
29	in RAC revenue shown on Schedule C1, Page 3, Line 6		

30 References:
31 Column A: Cooperative Schedule C1, Page 3, Line 6
32 Column B: Testimony, CSB
33 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-13

OPERATING INCOME ADJUSTMENT NO. 2 - NORMALIZED LEGAL EXPENSE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	2003 Legal Expenses	$ 233,076	**$ -**	$ 233,076
2	ACC Jurisdiction Adjudication Related Legal Exp	77,936	**(77,936)**	-
3	Redacted Legal Invoices Expense	5,863	**(5,863)**	-
4	Total	$ 316,875	**$ (83,799)**	$ 233,076

LINE NO.	Firm Name	Date	Invoice No.	Amount
5	ACC Jurisdiction Adjudication Related Legal Expenses			
6	Firm Name	Date	Invoice No.	Amount
7	Intentionally Left Blank	1/14/2003	227857	$ 10,685.38
8	Intentionally Left Blank	2/18/2003	230060	$ 9,094.48
9	Intentionally Left Blank	3/13/2003	231756	$ 1,196.12
10	Intentionally Left Blank	4/14/2003	233950	$ 2,381.67
11	Intentionally Left Blank	5/13/2003	236060	$ 7,048.99
12	Intentionally Left Blank	6/12/2003	238034	$ 2,784.83
13	Intentionally Left Blank	7/11/2003	240029	$ 2,085.00
14	Intentionally Left Blank	8/7/2003	241860	$ 6,330.52
15	Intentionally Left Blank	9/12/2003	243996	$ 11,122.36
16	Intentionally Left Blank	10/9/2003	245988	$ 15,816.34
17	Intentionally Left Blank	11/11/2003	248029	$ 9,390.04
18			Total	$ 77,935.73

LINE NO.	Firm Name	Date	Invoice No.	Amount
19	Redacted Legal Invoices			
20	Firm Name	Date	Invoice No.	Amount
21	Intentionally Left Blank	10/7/2003	250-0903C	$ 2,918.75
22	Intentionally Left Blank	2/14/2003	250-0103C	$ 1,706.92
23	Intentionally Left Blank	1/16/2003	250-1202C	$ 1,237.50
24			Total	$ 5,863.17

25 References:
26 Column A: Company Data Request Response CSB 2-40
27 Column B: Testimony, CSB
28 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-14

OPERATING INCOME ADJUSTMENT NO. 3 - EMPLOYEE VACANCY LEVEL NORMALIZATION

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Employee Vacancy Level Normalization	$ -	**$ (113,684)**	$ (113,684)

2		
3	2001 Employee Vacancy Level	(5)
4	2002 Employee Vacancy Level	(3)
5	2003 Employee Vacancy Level	(1)
6	Total	(9)
7	Division Factor	3
8	Normalized Vacancy Level	(3)
9	Less: Test Year Vacancy Level	(1)
10	Amount to Adjust Test Year Vacancy Level	(2)
11	Multiplied by:	$ 56,842
12	**Adjustment to Normalize Employee Vacancy Level**	**$ (113,684)**

13 References:

14 Column A: Company Data Request Response CSB 2-37
15 Column B: Testimony, CSB
16 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-15

OPERATING INCOME ADJUSTMENT NO. 4 - FOOD & OTHER EXPENSES

LINE NO.	DATA REQUEST RESPONSE	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	CSB 2-44	Southwest Trans - Food, Luncheons, Dinners	$ 23,387	$ (23,387)	$ -
2	CSB 6-6	Billings from Affiliates - Charitable Contributions	$ 2,751	$ (2,751)	$ -
3	CSB 6-6	Billings from Affiliates - Sponsorships	$ 187	$ (187)	$ -
4	CSB 6-6	Billings from Affiliates - Food	$ 6,537	$ (6,537)	$ -
5	CSB 6-6	Billings from Affiliates - Awards	$ 201	$ (201)	$ -
6	CSB 6-6	Billings from Affiliates - Party	$ 2,211	$ (2,211)	$ -
7	CSB 6-6	Billings from Affiliates - Meals & Entertainment	$ 4,814	$ (4,814)	$ -
8	CSB 6-8	Lobbying Costs Included in Memberships	$ 17,685	$ (17,685)	$ -
9		TOTAL	$ 57,773	$ (57,773)	$ -

10 References:

11 Column A: Cooperative Data Request Response CSB 2-44, 6-6, and 6-8
12 Column B: Testimony, CSB
13 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-16

OPERATING INCOME ADJUSTMENT NO. 5 - INTEREST EXPENSE ON LONG-TERM DEBT

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Interest Expense on Long-term Debt	$ 5,168,413	**$ 133,675**	$ 5,302,088

2 References:

3 Column A: Cooperative Schedule C-1
4 Column B: Testimony, CSB
5 Column C: Column [A] + Column [B]

RAMIREZ

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-04-0527

DIRECT

TESTIMONY

OF

ALEJANDRO RAMIREZ

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2004

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SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0527

The direct testimony of Staff witness Alejandro Ramirez addresses the following issues:

Operating Income, TIER and DSC Ratios – Staff recommends operating revenues no less than the $28,814,864 (excluding regulatory asset charge ("RAC") collections) proposed by Southwest Transmission Cooperative, Inc. ("SWTCO" or "Applicant") Staff calculates that the proposed revenues would provide a times interest earned ratio ("TIER") of 0.65 and a debt service coverage ("DSC") ratio of 0.81. Staff has also calculated a TIER of 1.13 and a DSC of 1.02 when including the RAC. The Applicant's proposed revenue fails to provide sufficient internally generated cash flow, directly or indirectly through incremental debt financing, for plant replacement, improvement and expansion requirements.

Capital Structure – The Applicant's actual end of test year capital structure was composed by 95.3 percent debt and 4.7 percent patronage equity. This is an excessively leveraged capital structure. This rate case is the appropriate time to address SWTCO's highly leveraged capital structure. The capital structure issue is important because a highly leveraged capital structure has potentially detrimental impacts for service reliability and rates. The Applicant has not demonstrated that its proposed revenue is consistent with the Commission's order (Decision No. 64991, dated June 26, 2002) to establish long-range goals to improve its patronage equity position. Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff further recommends that the Commission restrict the distribution of future patronage dividends by SWTCO until it has achieved a capital structure composed of at least 30 percent equity.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my position as a Public Utilities Analyst, I perform studies to estimate the cost of capital component of the revenue requirement in rate proceedings. I also perform other financial analyses.

Q. Please describe your educational background and professional experience.

A. In 2002, I graduated summa cum laude from Arizona State University, receiving a Bachelor of Science degree in Global Business with a specialization in finance. While attending Arizona State University, I successfully completed the Barrett Honors College curriculum. My course of studies included classes in corporate and international finance, investments, accounting, statistics, and economics. I began employment as a Staff Public Utilities Analyst in 2003. Since that time, I have provided recommendations to the Commission on financings and prepared various studies in the field of cost of capital and econometrics. I have also attended seminars related to general regulatory and business issues.

Q. What is the scope of your testimony in this case?

A. I discuss Southwest Transmission Cooperative, Inc.'s ("SWTCO" or "Applicant") current capital structure and provide Staff's recommended operating income. I also provide the times interest earned ("TIER") and debt service coverage ("DSC") ratios resulting from Staff's recommended operating income.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. This testimony is organized in three sections. Section I presents the Applicant's long-term debt and patronage equity balances. Section II discusses SWTCO's capital structure. Finally, Section III discusses Staff's recommended operating income, TIER and DSC ratios for the Applicant.

Q. Have you prepared any exhibits to your testimony?

A. Yes. I prepared three schedules (AXR-1 to AXR-3) that support Staff's recommendations.

Q. What is Staff's recommended operating income for the Applicant?

A. Staff recommends an operating income no less than $3,439,610 for SWTCO (which is the operating income that would result from the Applicant's proposed revenues).

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $3,439,610?

A. Staff has calculated that an operating income of $3,439,610 would allow SWTCO to achieve a TIER of 0.65 which also equates to a 0.81 DSC. Staff has also calculated a TIER of 1.13 and a DSC of 1.02 when including the Regulatory Asset Charge ("RAC") (Schedule AXR-4). Only by taking the RAC into account does the Applicant have the capacity to meet its debt service obligations.

SWTCO'S LONG-TERM DEBT AND PATRONAGE EQUITY BALANCE

Q. What is the amount of SWTCO's long-term debt outstanding?

A. The Applicant had $94,164,787 in long-term debt outstanding as of November 1, 2004, and it is expected to incur $5,302,088 in interest expense related to its long-term debt during the year.

Q. What were SWTCO's patronage equity balances for the years ended 2003, 2002 and 2001?

A. SWTCO's patronage equity balances for the years ended 2003, 2002 and 2001 were $4,240,180, $2,218,235 and $1,812,664, respectively.

SWTCO'S CAPTIAL STRUCTURE

Q. What was SWTCO's actual end of test year capital structure?

A. The Applicant's actual end of test year capital structure was composed by 95.3 percent debt and 4.7 percent patronage equity[1]. Schedule AXR-1 presents the Applicant's capital structures for the years 2001, 2002 and 2003.

Q. Is SWTCO concerned with its current capital structure?

A. Yes. In his direct testimony, the Applicant's witness, Mr. William K. Edwards, has emphasized the importance for SWTCO to develop a stronger equity base. Moreover, Mr. Edwards recognizes and supports the efforts made by both the Commission and SWTCO to establish long-term goals for SWTCO's patronage equity (Decision No. 64991, dated June 26, 2002).

[1] Staff has calculated the capital structure by taking into account long-term debt and equity.

Q. How does SWTCO's capital structure compare to other G&T utilities' capital structure?

A. Mr. William Edwards has compared SWTCO's capital structure to the Capital structure of 55 G&T utilities' capital structure. As mentioned in his testimony, SWTCO's capital structure is more leveraged than Mr. Edwards' G&T utilities sample (See Mr. Edwards Direct Testimony, Page 10, Line 18-21). Schedule AXR-2 presents the capital structure of some G&T cooperatives that are rated by *Standard & Poor's* ("S&P") and the Applicant's capital structure for the test year ended December 2003. The average capital structure of the G&T cooperatives is composed of 81.0 percent debt and 19.0 percent patronage equity as opposed to the Applicant's capital structure composed of 95.3 percent debt and 4.7 percent patronage equity.

Q. Is Staff concerned with the Applicant's actual end of test year capital structure?

A. Yes. SWTCO's capital structure is highly leveraged as it has remained for several years. The Applicant's capital structure has multiple potential negative effects including: (1) higher debt costs for new issuances; (2) reduced ability to incur new debt and finance capital improvements; and (3) places upward pressure on rates to cover debt service obligations.

Q. Has the Commission shown concern with highly leveraged cooperatives?

A. Yes. The Commission ordered SWTCO (Decision No. 64991, dated June 26, 2002) and Arizona Electric Power Cooperative ("AEPCO") (Decision No. 64227, dated November 29, 2001) to establish long-range goals to improve their patronage equity positions. In addition, the Commission ordered Trico Electric Cooperative, Inc. ("Trico") to file a capital improvement plan with the Commission (Decision No.67412, dated November 2, 2004). As discussed previously, highly leveraged capital structures present potentially negative consequences.

Q. Does the Rural Utilities Service ("RUS") have any restrictions in regard to distribution of patronage dividends for highly leverage cooperatives?

A. Yes. SWTCO's audited financial statements for the years ended December 31, 2003 and 2002, state "RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative (See Exhibit GEP-1, note to financial statement 7)".

Q. Does the National Rural Utilities Cooperative Finance Corporation ("CFC") have any restrictions in regard to distribution of patronage dividends for highly leverage cooperatives?

A. Yes. The CFC requires a borrower to have a capital structure composed of at least 30 percent patronage equity to distribute 100 percent of its net earnings as patronage dividends. If the borrower has a capital structure composed of less than 30 percent patronage equity, it would be able to distribute as patronage dividends only 30 percent of its patronage capital or operating margins for the preceding year.

Q. What approach does Staff recommend to improve SWTCO's capital structure?

A. Staff recommends steadily growing the Applicant's patronage equity by setting rates that balance the interest of the ratepayers and SWTCO's long-term financial health. SWTCO has not shown how its proposed rates will improve its highly leveraged capital structure in a reasonable timeframe. Staff anticipates that the Applicant will use the opportunity provided by rebuttal testimony to explain how its proposed rate will adequately satisfy its capital structure deficiency.

III. OPERATING INCOME, TIER AND DSC RATIOS

Q. What do the times interest earned ratio ("TIER") and debt service coverage ratio ("DSC") represent?

A. TIER represents the number of times operating income covers interest expense on long-term debt. A TIER greater than 1.0 means that operating income is greater than interest expense.

DSC represents the number of times internally generated cash covers required principal and interest payments on long-term debt. A DSC greater than 1.0 indicates that operating cash flow is sufficient to cover debt obligations.

Q. Do the Applicant's lenders have debt covenants for TIER and DSC?

A. Yes. The Rural Utilities Service ("RUS") requires SWTCO to maintain a minimum TIER of 1.05 and a minimum DSC of 1.0 on an annual average best two of three years basis.

Q. What TIER and DSC level does the Applicant claim will result from its proposed revenues?

A. The Applicant claims its proposed revenues would result in a 1.15 TIER and a 1.11 DSC. SWTCO's witness, Mr. Edwards, states in his direct testimony that "...these are minimum ratios to provide some financial stability and *modest progress* toward equity goals [emphasis added] (Mr. Edwards Direct Testimony, Page 11, Line 4 & 5)". Moreover, Mr. Edwards recognizes that SWTCO has a long way to go towards improved financial strength.

Q. What TIER and DSC level does Staff conclude would result from the Applicant's proposed revenues?

A. Staff has calculated that SWTCO's proposed increase in revenues would result in a TIER of 0.65 which also equates to a 0.81 DSC. Staff has also calculated a TIER of 1.13 and a DSC of 1.02 when including the Regulatory Asset Charge ("RAC") (Schedule AXR-4). Only by taking the RAC into account does the Applicant have the capacity to meet its debt service obligations.

Q. Has the Applicant demonstrated that its proposed revenues are sufficient to improve its equity position in a reasonable timeframe?

A. No. The Applicant has provided not support to demonstrate that its proposed revenues are insufficient to provide patronage equity growth to achieve a capital structure of at least 30 percent patronage equity in a reasonable timeframe.

Q. What operating revenues does Staff recommend?

A. Staff recommends operating revenues no less than what SWTCO is proposing ($28,814,864 without taking into account the RAC or 31,374,790 including the RAC). Staff recognizes that the Applicant's proposed revenues barely allow the Applicant to cover its debt service. Staff also recognizes that to improve its equity position in a reasonable timeframe, higher rates are needed.

CONCLUSION

Q. Please summarize Staff's recommendations.

A Staff recommends that the Commission adopt a revenue requirement no less than that proposed by the Applicant. The Applicant's proposed revenues fail to provide sufficient internally generated cash flow to finance, directly or indirectly through additional future debt financing, plant replacement, improvement and expansion requirements. The Applicant has not demonstrated that its proposed revenue is consistent with the Commission's order (Decision No. 64991, dated June 26, 2002) to establish long-range goals to improve its patronage equity position. Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff also recommends that the Commission restrict the distribution of future patronage dividends by SWTCO until it has achieved a capital structure composed of at least 30 percent patronage equity.

Q. Does this conclude your direct testimony?

A. Yes, it does.

SWTCO'S HISTORICAL CAPITAL STRUCTURE

Year	Debt	Equity
2001	98.1%	1.9%
2002	97.5%	2.5%
2003	95.3%	4.7%

Source: Based on the Applicant's filing

SAMPLE G&T COOPERATIVES' CAPITAL STRUCTURE

G&T Coops	% Debt[1]	% Patronage Equity[1]
Associated Electric Coop., Inc.	78.0%	22.0%
Arkansas Electric Coop., Inc.	56.6%	43.4%
Old Dominion Electric Cooperative	77.9%	22.1%
Basin electric Power Cooperative	61.1%	38.9%
Central Iowa Power	78.4%	21.6%
Oglethorpe Power	89.2%	10.8%
Seminole Electric Cooperative	90.5%	9.5%
Tri-state Generating & Transmission Assoc.	85.2%	14.8%
Hoosier Energy Rural Electric Coop., Inc.	88.1%	11.9%
Chugach Electric Association	74.4%	25.6%
Alabama Electric Coop., Inc.	91.3%	8.7%
Western Farmer's electric	91.7%	8.3%
Great River Energy	90.8%	9.2%
Average	81.0%	19.0%
Southwest Transmission Cooperative, Inc.[2]	95.3%	4.7%

[1] Information based on annual reports for the year ended 2003
[2] Based on the Company's rate filing

SWTCO'S TIER and DSC With Staff's Recommended Rates[1]

1	Operating Income	$ 3,439,610	**TIER Without RAC**	
2	Regulatory Asset Charge ("RAC")	$ 2,559,926	[1+5] ÷ [7]	0.65
3	Total Regulated Revenues	$ 5,999,536	**TIER With RAC**	
4	Depreciation & Amort.	$ 6,852,107	[3+5] ÷ [7]	1.13
5	Income Tax Expense	$ -		
6				
7	Interest Expense	$ 5,302,088	**DSC Without RAC**	
8	Repayment of Principal	$ 7,358,610	[1+4+5] ÷ [7+8]	0.81
			DSC With RAC	
			[3+4+5] ÷ [7+8]	1.02

[1] The amounts reflect Staff's pro forma adjustments and Staff's minimum recommended revenue

CASPER

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE	))))	DOCKET NO. E-04100A-04-0527

DIRECT

TESTIMONY

OF

ERIN CASPER

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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SCHEDULES

EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-04100A-04-0527

Southwest Transmission Cooperative, Inc. ("Southwest" or "The Cooperative") provides transmission service to its six Class A Member distribution cooperatives including Anza Electric Cooperative, Inc., Duncan Valley Electric Cooperative, Inc., Graham County Electric Cooperative, Inc., Mohave Electric Cooperative, Inc., Sulphur Springs Valley Electric Cooperative, Inc., and Trico Electric Cooperative, Inc. Southwest also provides transmission service to its Class B Members including AEPCO and Morenci Water & Electric Company. Finally, Southwest provides wholesale transmission service to non-members through its open access transmission tariff ("OATT") and through pre-OATT contracts.

On July 23, 2004, Southwest filed an Application for a Rate Increase. The Cooperative requested an increase in revenue of $3,666,668 resulting in an increase of 13.7 percent to overall revenues. The Cooperative's proposed rates are designed to recover its proposed revenue requirement of $28,814,864 net of revenues collected through the regulatory asset charge.[1] Southwest proposed an increase in the firm and non-firm point-to-point rates of 7.8 percent and an increase in the firm network service revenue requirement of 26.2 percent. The Cooperative requested that it be allowed to pass through an increase in rates charged by AEPCO for generation-related ancillary services provided by AEPCO. Finally, Southwest proposed a decrease to its Schedule 1: System Control and Load Dispatch of 37.9 percent. Southwest has proposed no changes to the structure of its rates or its service offerings.

Staff has recommended a revenue requirement net of revenues collected through the regulatory asset charge equal to $28,814,864. Staff's recommended rates are designed to recover Staff's recommended revenue requirement. Staff recommends an increase in the rates for firm and non-firm point-to-point service of 7.45 percent and an increase in the network service revenue requirement of 26.30 percent. Staff recommends an increase in the cost-based ancillary service rates commensurate with Staff's recommendations for the associated costs and plant balances. Finally, Staff recommends a decrease in the rate for Schedule 1: System Control and Load Dispatch of 37.86 percent. Staff recommends no changes to the structure of Southwest's rates or its service offerings.

Staff's recommended rate design is intended to recover revenues equal to Staff's recommended revenue requirement. Staff has designed rates consistent with standard FERC embedded cost ratemaking methods. Staff proposes no changes to the structure of Southwest's rates or its service offerings.

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[1] Southwest's proposed revenue includes revenues from the regulatory asset charge and is equal to $28,814,864 + $2,707,122 = $31,521,986.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Erin Casper. I am a Public Utility Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Avenue, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utility Analyst.

A. In my capacity as a Public Utility Analyst, I provide recommendations to the Commission on energy and telecommunications issues. My current energy-related responsibilities include review and evaluation of demand-side management issues, utility rate-case filings, and rate design.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Wisconsin in 2001, receiving a Bachelor of Science degree in Economics and Music. From May, 2001 to May, 2004, I was a Staff Economist with the economic consulting firm of Laurits R. Christensen Associates in Madison, Wisconsin. As a Staff Economist, I worked on projects in the electric and gas utilities industry and in patent infringement and antitrust litigation cases. Among my duties as a Staff Economist, I prepared rate-case filing schedules and analysis for both electric and gas utilities including revenue requirement, cost of capital, cost of service, and rate design. Since joining the Arizona Corporation Commission in June of 2004, I have attended various seminars and classes on general energy industry and regulatory issues.

Q. What is the scope of your testimony in this case?

A. I will address the cost allocation and rate recommendations for Southwest Transmission Cooperative's ("Southwest" or "Southwest Transmission" or "Cooperative") application for a general rate increase. In particular, I will explain the calculation of the point-to-point and network transmission rates, ancillary service rates, and adjustments to recognize certain grandfathered and discounted point-to-point contracts. I will also describe the process by which ancillary services are offered to customers by Southwest via Arizona Electric Power Cooperative ("AEPCO"). Staff witnesses Crystal Brown, Alejandro Ramirez, and Jerry Smith will provide testimony covering other aspects of Southwest's rate application.

SUMMARY OF RECOMMENDATIONS

Q. Briefly summarize the important concepts in transmission ratemaking.

A. The Federal Energy Regulatory Commission ("FERC") has established that transmission providers must offer transmission service on a non-discriminatory open access basis. FERC Order No. 888 requires that a transmission company file an open access transmission tariff ("OATT") that offers firm and non-firm point-to-point service, firm network service, and six ancillary services. In that order, FERC indicated that it would consider alternative pricing methodologies, but that embedded cost-based rates would remain acceptable. Additionally, FERC indicated that while developing point-to-point rates using the annual system peak ("1 CP") is the standard methodology, it would no longer summarily reject firm point-to-point rates based on different cost allocations such as the average of the twelve monthly peaks ("12 CP"). With respect to network service, FERC concluded that the load ratio allocation method would remain the standard methodology but that it would consider rates based on different cost allocation methods on a case by case basis. FERC Order No. 888 also established that transmission providers must offer six ancillary services including (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve-Spinning; and (6)

Operating Reserve-Supplemental. The pro forma OATT sets forth standard rate design methodologies for point-to-point, network, and ancillary services.

Q. Please explain how Transmission Cooperatives are treated differently than Investor Owned Utilities both at the Federal and State levels.

A. Southwest is financed by the Rural Utility Service ("RUS") Fund and therefore claims status as a non-FERC jurisdictional entity. FERC Order No. 888 established that non-public or non-jurisdictional utilities that own, operate, or control transmission facilities must provide reciprocal transmission service as a condition of receiving open access transmission service from public utilities. One method of satisfying the reciprocity requirement is for the non-public utilities to voluntarily file a "safe harbor" OATT with FERC. The "safe harbor" tariff filings are subject to less regulatory scrutiny on the federal level than the tariffs filed by public utilities. FERC generally finds the OATT appropriate for "safe harbor" status if the tariff is substantially similar to the pro forma OATT set forth in Order No. 888. On May 10, 2004, FERC issued an order clarifying the "safe harbor" status of the OATT filed by Southwest.

The Arizona Corporation Commission has jurisdiction over the rates and charges assessed by Southwest. The Commission also has jurisdiction over Southwest's tariff. The Commission approved the rates and charges contained in Southwest's current OATT in Decision No. 65367.

Q. Please identify the different types of transmission rates included in the rate design.

A. Southwest Transmission offers firm and non-firm point-to-point transmission service, firm network transmission service, and six ancillary services (1) Scheduling, System Control and Dispatch Service ("Schedule 1"); (2) Reactive Supply and Voltage Control ("Schedule

2"); (3) Regulation and Frequency Response Service ("Schedule 3"); (4) Energy Imbalance Service ("Schedule 4"); (5) Operating Reserve-Spinning ("Schedule 5"); and (6) Operating Reserve-Supplemental ("Schedule 6").

Q. In general, how did Staff calculate the recommended rates?

A. Staff calculated rates based on embedded costs for firm and non-firm point-to-point service, firm network service, and the six required ancillary services. The Total Transmission Revenue Requirement ("TTRR") is equal to Staff's recommended Total Revenue Requirement for Southwest Transmission less revenues from Schedule 1: Load Dispatching and System Control, Direct Assignment Facilities, Special Contracts, and Other Revenues. Point-to-point rates are calculated using the TTRR and the annual coincident peak demand. The monthly network transmission service revenue requirement is equal to the TTRR less the point-to-point revenues divided by twelve. Rates for the six ancillary services are cost-based and explained later in my testimony.

Q. What is the Cooperative's proposed rate design?

A. Southwest Transmission has proposed the following changes to its rates:

Transmission Service	Present Rate	Cooperative Proposed Rate	% Change From Present
Firm Point-to-Point ($ / kW)	$2.805	$3.032	7.78%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.032	7.78%
Firm Network Service - Annual Rev. Req.	$13,104,193	$17,021,676	26.16%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,418,473	26.16%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.051	-9.35%
Schedule 2 – Network ($ / kW)	$0.065	$0.064	-1.55%
Schedule 3 ($ / kW)	$0.518	$0.411	-23.14%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$20.71	-10.49%
Schedule 5 ($ / kW)	$0.685	$0.621	-9.83%
Schedule 6 ($ / kW)	$0.343	$0.411	18.09%

Q. Did Staff adopt the ratemaking methodology used by Southwest Transmission in its proposed rate design?

A. In general, Staff employed the methods of cost allocation and rate design used by Southwest in its rate calculations. Staff has accepted Southwest's use of the annual system peak demand in the calculation of point-to-point rates. Staff has accepted the Cooperative's method of allocating the network service monthly revenue requirement based on its customers' load ratio shares. Staff has also utilized Southwest's cost allocation methodology for the purpose of determining the ancillary service rates (Schedules 1-6).

Q. What is Staff's recommended rate design?

A. Based on Staff's overall revenue requirement, Staff recommends the following rates for Southwest Transmission Cooperative.

Transmission Service	Present Rate	Staff	% Change From Present	% Change From Cooperative Proposed
Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	-0.33%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	-0.33%
Firm Network Service - Annual Rev. Req.	$13,104,193	$17,046,503	26.30%	0.15%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,420,542	26.30%	0.15%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%	0.00%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.064	13.35%	22.71%
Schedule 2 – Network ($ / kW)	$0.065	$0.080	20.76%	22.31%
Schedule 3 ($ / kW)	$0.518	$0.428	-19.09%	4.05%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$20.32	-12.39%	-1.90%
Schedule 5 ($ / kW)	$0.685	$0.646	-5.80%	4.11%
Schedule 6 ($ / kW)	$0.343	$0.417	19.54%	1.45%

Q. Explain the differences in Staff's recommended rate design versus the Cooperative's proposed rate design.

A. Staff's recommended revenue requirement net of regulatory asset revenues is equal to Southwest's $28,814,864 proposed revenue requirement net of regulatory asset revenues. Staff's recommended revenue requirement is discussed in detail in the testimony of Staff witness Brown.

As explained in greater detail below, the calculations of point-to-point and network service rates are largely based on the transmission revenue requirement and billing kW. However, where rate base, operating expenses, and/or the operating margin are used explicitly to calculate rates, Staff's recommendations are used. For example, several point-to-point customers have discounts that are based, in part, on rate base, operating expenses, and operating margin. The cost-based ancillary service rates are also based in part on rate base, operating expenses, and operating margin. To the extent that Staff's recommendations for those items deviate from the Cooperative's proposed adjusted test year numbers, Staff's proposed rates will differ from the rates proposed by Southwest.

Q. Please discuss the billing KW and kWh Staff has used in your rate design.

A. In its original filing, Southwest provided both 2003 test year and forecasted 2004 billing data for network customers. Southwest provided annualized 2003 test year loads for its point-to-point customers. In its rate calculations, the Cooperative utilized the forecasted 2004 demands for its network customers along with the annualized 2003 contracted loads for its point-to-point customers. Staff has accepted the annualization adjustments made by Southwest for its point-to-point loads, and has used these billing units in the rate design. The adjustments recognize the termination of a 17.5 MW contract with the City of Mesa, a change in the contract with the Town of Thatcher. Staff believes these adjustments to contracted point-to-point loads are reasonable because they are known and measurable. However, it is Staff's general practice to use test year billing data. As such, Staff does not accept the 2004 forecasted load data for the Cooperative's network customers. Staff has used the 2003 test year billing data for network loads. Schedule EEC-1 shows the differences in billing data utilized by Southwest and Staff in the rate design.

Q. How does Staff's use of the 2003 test year billing kW for network loads affect the rate calculation?

A. As is discussed below, the calculation of the point-to-point rate is dependent on the annual system coincident peak demand. Using the 2003 test year billing kW rather than the forecasted 2004 demand increases the annual system coincident peak demand slightly. The slight increase in annual system peak demand results in a slightly lower point-to-point rate.

In addition, the actual 2003 test year billing units yield different load ratio shares and subsequently, a different estimated allocation of the network service revenue requirement among Southwest's network customers than do the forecasted billing units. However, this estimated allocation is for informational purposes only. When new rates take effect, the actual 12-month rolling average load ratio shares will be used to allocate the network service revenue requirement among Southwest's network service customers.

POINT-TO-POINT TRANSMISSION SERVICE

Q. Please explain point-to-point transmission service.

A. Point-to-point transmission service is the reservation and transmission of capacity and energy on either a firm or non-firm basis from designated point(s) of receipt to designated point(s) of delivery. Points of receipt are points of interconnection between the transmission provider and the customer or a 3rd party at which power is received onto the transmission provider's system. Points of delivery are points at which power is delivered by the transmission provider to the receiving party.

Q. Please describe the calculation of the firm point-to-point transmission service rates.

A. Firm point-to-point ("PTP") rates are calculated by dividing the Total Transmission Revenue Requirement ("TTRR") by the Annual Coincident Peak Demand ("1 CP") of Southwest's system. Please see Schedule EEC-2 for the calculation of the PTP rate. The TTRR equals the Total Revenue Requirement less revenues from Schedule 1: Load Dispatching and System Control, Direct Assignment Facilities, Special Contracts, and

Other Revenues. The TTRR represents the amount of revenue that must be collected by point-to-point and network transmission service customers. Based on Staff's recommended overall revenue requirement and the system 1 CP, the recommended point-to-point rate is $3.022/kW. This represents an increase of 7.45 percent over Southwest's present rate.

Q. Please explain why the Annual Coincident Peak Demand is used to calculate the firm point-to-point transmission rate.

A. In Order No. 888, FERC allowed transmission providers more flexibility in setting rates as it did not mandate the use of a particular cost allocation methodology. FERC stated that it would no longer "summarily reject a firm point-to-point transmission rate developed by using the average of the 12 monthly system peaks."[2] However, using the annual system peak remains as a standard methodology. The use of 1 CP yields a lower PTP rate than the use of the twelve monthly system peaks ("12 CP") because the TTRR is divided by a larger denominator using the 1 CP. Southwest explained its rationale for using 1 CP to set point-to-point rates in its response to Staff's Ninth Set of Data Requests. The Cooperative stated that the use of the 1 CP in setting PTP rates reflects its need to remain competitive with neighboring utilities' point-to-point service rates. In addition, Southwest recognized that point-to-point transmission service is a less valuable service than network service and rates should reflect that fact.[3]

Staff acknowledges that point-to-point service is a less valuable transmission service than network service which allows a customer to integrate and economically dispatch its resources. As such, it is appropriate for pricing to reflect the relative value of the services. In addition, Southwest's transmission system was primarily built to serve its network

[2] FERC Order No. 888 page 301.
[3] Response to Staff's ninth set of data requests: 9-1.

customers, and it is the network customers that have priority with respect to the available transmission capacity. Southwest is entitled to recover its entire revenue requirement even if it is only serving network customers. To the extent there is available capacity, it is in the interest of the network customers for Southwest to offer and provide point-to-point service to non-member customers. Revenues from PTP service directly offset the network service revenue requirement that is allocated among the network customers. Staff concludes that it is in the interest of Southwest's members for the point-to-point rate to remain competitive. Using the 1 CP to set the PTP rate yields a lower and more competitive rate than the 12 CP.

Q. Did Staff consider any grandfathered contracts between Southwest and any of its customers in its recommended rate design?

A. Yes. The total transmission revenue requirement must be recovered through point-to-point and network services. To the extent that Southwest is contractually obligated to provide service on a discounted basis to certain point-to-point customers, those discounts must be considered when setting rates that are designed to recover the total transmission revenue requirement. Therefore, the total revenue recovered from point-to-point transmission service reflects revenues collected from the standard point-to-point rates as well as the discounted rates for Morenci Water & Electric and the Town of Thatcher.

Q. Briefly describe the discount applied to the point-to-point rate for Morenci Water & Electric.

A. Under its firm PTP service agreement with Southwest, Morenci Water & Electric ("MW&E") receives a discount based on the revenue requirement associated with the Greenlee 345/230 kV Transformer. The discount reflects MW&E's bypass of the Greenlee transformer. Whereas the standard PTP rate is calculated by dividing the TTRR by the Annual Coincident Peak Demand ("1 CP"), the MW&E discounted PTP rate is calculated by dividing the TTRR less the revenue requirement associated with the Greenlee Transformer by the 1 CP. See Schedule EEC-3 for the calculation of the discount applied to the PTP rate for MW&E. Staff's recommended point-to-point rate for MW&E is $3.007/kW. This represents a discount of $0.015/kW from the recommended standard point-to-point rate.

Q. Briefly describe the discount applied to the point-to-point rate for the Town of Thatcher.

A. Under its firm PTP service agreement with Southwest, the Town of Thatcher ("Thatcher") receives a discount based on the expenses associated with Southwest's wheeling contract with the Western Area Power Administration ("WAPA"). The discount reflects Thatcher's use of its own WAPA rights that allow it to avoid using Southwest's system from the Westwing Substation to the Apache Substation. Whereas the standard PTP rate is calculated by dividing the TTRR by the Annual Coincident Peak Demand ("1 CP"), the Thatcher discounted PTP rate is calculated by dividing the TTRR less the expenses associated with the WAPA wheeling contract by the 1 CP. See Schedule EEC-4 for the calculation of the discount applied to the PTP rate for Thatcher. Staff's recommended point-to-point rate for the Town of Thatcher is $2.605/kW. This represents a discount of $0.417/kW from the recommended standard point-to-point rate.

Q. Please describe the calculation of the non-firm point-to-point transmission service rates.

A. FERC Order No. 888 established that the non-firm rate for point-to-point service should be capped at the firm rate. FERC concluded that pricing flexibility for non-firm service is acceptable but that any discounts given for non-firm point-to-point service must be offered to all similarly situated customers. In its current OATT, Southwest sets forth its rate for non-firm PTP transmission service. The current rate for non-firm PTP service is equal to the firm PTP rate. Southwest has indicated that it provides non-firm PTP service on a limited and non-discriminatory basis.[4] The Cooperative's proposed non-firm rate for point-to-point service is set equal to the firm rate. Consistent with current practice, Staff's recommended non-firm point-to-point transmission rate is set equal to the recommended firm rate of $3.022/kW. Please see Schedule EEC-2 for the calculation of the firm and non-firm point-to-point rates.

NETWORK TRANSMISSION SERVICE

Q. Please explain network transmission service.

A. Network transmission service allows a customer to efficiently and economically dispatch and regulate its network resources to serve its network load within the area served by the transmission provider. Essentially, a customer taking service under Southwest's network transmission service tariff may inject power at any point on the system for delivery to any point on the system so long as those delivery points are designated as "network load." Network service allows a transmission customer to use Southwest's transmission system in a comparable manner to the way in which a vertically integrated utility uses its own transmission system.

Q. Please describe the calculation of the firm network transmission service rates.

A. Network transmission service is priced differently than point-to-point in that the average dollar per kW may change from month to month for a given customer. The pro forma OATT established by FERC Order No. 888 allows a transmission utility to set an annual network service transmission revenue requirement ("NSRR") to be allocated among all

[4] Southwest Transmission's Responses to Staff's Ninth Set of Data Requests: STF 9-3.

network transmission customers. The annual network service transmission revenue requirement is equal to the Total Transmission Revenue Requirement less the point-to-point revenues. Please see Schedule EEC-5 for the total revenues from point-to-point customers. The annual NSRR is divided by twelve to obtain the monthly NSRR. Schedule EEC-6 presents the calculation of the network service revenue requirement. Staff's recommended monthly NSRR is $1,420,542. The monthly NSRR is allocated among Southwest's network service customers using each customer's load ratio share. Each customer's load ratio share is equal to that customer's twelve-month rolling average network transmission service demand (measured in kW) divided by the total of all network service customers' twelve-month rolling average demand. Each customer's load ratio share is computed monthly. Each customer pays its monthly load ratio share times the monthly NSRR. Schedule EEC-7 shows the estimated allocation of the network service revenue requirement among Southwest's network service customers. Load Ratios used in revenue allocation shown in Schedule EEC-7 are based on 2002 and 2003 billing kW. When new rates take effect, actual rolling 12-month average Load Ratio Shares will be used to allocate the Network Service Revenue Requirement.

ANCILLARY SERVICES

Q. Please explain the six ancillary services that Southwest is required to offer.

A. Ancillary services are those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission provider's transmission system. FERC requires that transmission providers offer six ancillary services. Scheduling, System Control and Dispatch Service ("Schedule 1") is required to schedule the movement of power through, out of, within, or into a control area. Reactive Supply and Voltage Control ("Schedule 2") is the provision of reactive power needed to maintain transmission voltage on the transmission facilities within acceptable limits. Regulation and Frequency Response Service ("Schedule 3") provides the continuous balancing of resources and load to maintain scheduled interconnection frequency at sixty cycles per second. Energy Imbalance Service ("Schedule 4") is provided when a difference occurs between scheduled and actual delivery of energy to a load located within a control area over an hour. Operating Reserve-Spinning ("Schedule 5") provides reserve power needed to serve load immediately to maintain reliability in the event of a system contingency. Operating Reserve-Supplemental ("Schedule 6") provides reserve power needed to serve load within fifteen minutes to maintain reliability in the event of a system contingency.

Of these services, FERC determined that the transmission provider is required to provide and the customer must purchase from the provider the first two services (Schedules 1-2). The remaining four services (Schedules 3-6) must be offered by the transmission provider but the customer has the option to acquire the services from the transmission provider, a third party, or self-provide.

Q. Please explain the calculation of the rate for Schedule 1: System Control and Load Dispatch.

A. The rate for Schedule 1 is based on Southwest's costs to schedule the movement of power through, out of, within, or into its control area. The rate is based on the system control and load dispatching expenses incurred by Southwest less the payment from AEPCO for the use of the Energy Management System owned by Southwest divided by the average capacity of the generation dispatched by Southwest. Schedule EEC-8 shows the calculation of the rate for Schedule 1. Staff's recommended rate for Schedule 1 is equal to Southwest's proposed rate of $0.289/kW which represents a decrease of 37.86 percent from the present rate. Southwest explained that the proposed decrease in the rate for

Schedule 1 is a result of the reclassification of revenue credits including the Energy Management System payment from AEPCO and an increase in generating capacity.[5]

Q. Is Southwest capable of providing all of the ancillary services using its own facilities?

A. As a stand-alone transmission provider, Southwest does not have its own source of generation resources with which to provide the generation-related ancillary services including Reactive Supply and Voltage Control, Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental ("Schedules 2-6"). In order to fulfill its obligation to offer these five generation-related ancillary services, the Cooperative procures them from AEPCO. The rates charged to Southwest by AEPCO for its ancillary services are based on AEPCO's embedded costs to provide these services. Southwest passes the cost-based rates directly on to its transmission customers.

Q. Do the rates for the generation-related ancillary services reflect Southwest's costs?

A. Indirectly, the rates that Southwest has proposed for Schedules 2-6 reflect its costs to provide those services in that they are the rates they will pay AEPCO to provide those services to its customers. However, the costs included in the "cost-based" rates for Schedules 2-6 are costs that AEPCO incurs to provide those services.

Q. Did Staff use AEPCO's costs to calculate the rates for the generation-related ancillary services?

A. Yes. Although Schedules 2-6 are included in Southwest's open access transmission tariff, the costs to provide these generation-related services are incurred by AEPCO and passed on to Southwest. Therefore, Staff's recommended expenses, plant balances, and revenue

[5] Southwest Transmission's Responses to Staff's Ninth Set of Data Requests: STF 9-12.

requirements for AEPCO were used to calculate the rates for Schedules 2–6. Schedules 9, 10, and 11 show the derivation of the generation-related ancillary services.

Q. Is Southwest earning a rate of return on Schedules 2-6?

A. No. When a customer buys any generation-related ancillary services from Southwest, Southwest purchases those services from AEPCO at cost-based rates and passes AEPCO's cost-based rates on to the customer. The rate the customer pays for generation-related ancillary services is the same cost-based rate that Southwest pays to AEPCO for the provision of the generation-related ancillary services.

REGULATORY ASSET CHARGE

Q. Please explain the Regulatory Asset Charge.

A. Pursuant to Decision No. 62758, Southwest was authorized to collect a Regulatory Asset Charge ("RAC") to be assessed against all kWh sold to Southwest's Class A members according to the schedule set forth in the order. The RAC is to remain in effect until the full amount of regulatory assets assumed by Southwest is recovered. The initial total regulatory assets to be recovered was equal to $21,849,000. The RAC is to be collected over an eleven year period from December, 1999 through December, 2012 and is adjusted downward on an annual basis as set forth in the order. The RAC rate for 2005 is equal to $0.00133 per kWh as specified in Decision No. 62758 and Southwest's current OATT.

Q. What is Staff's recommendation with respect to the Regulatory Asset Charge?

A. Staff recommends that the Commission require Southwest to provide annual status reports that detail how much revenue has been collected through the RAC since December, 1999. The report should detail the billing kWh, RAC rate, and revenues collected through the

EXHIBIT 1
Location and Orientation of Photos

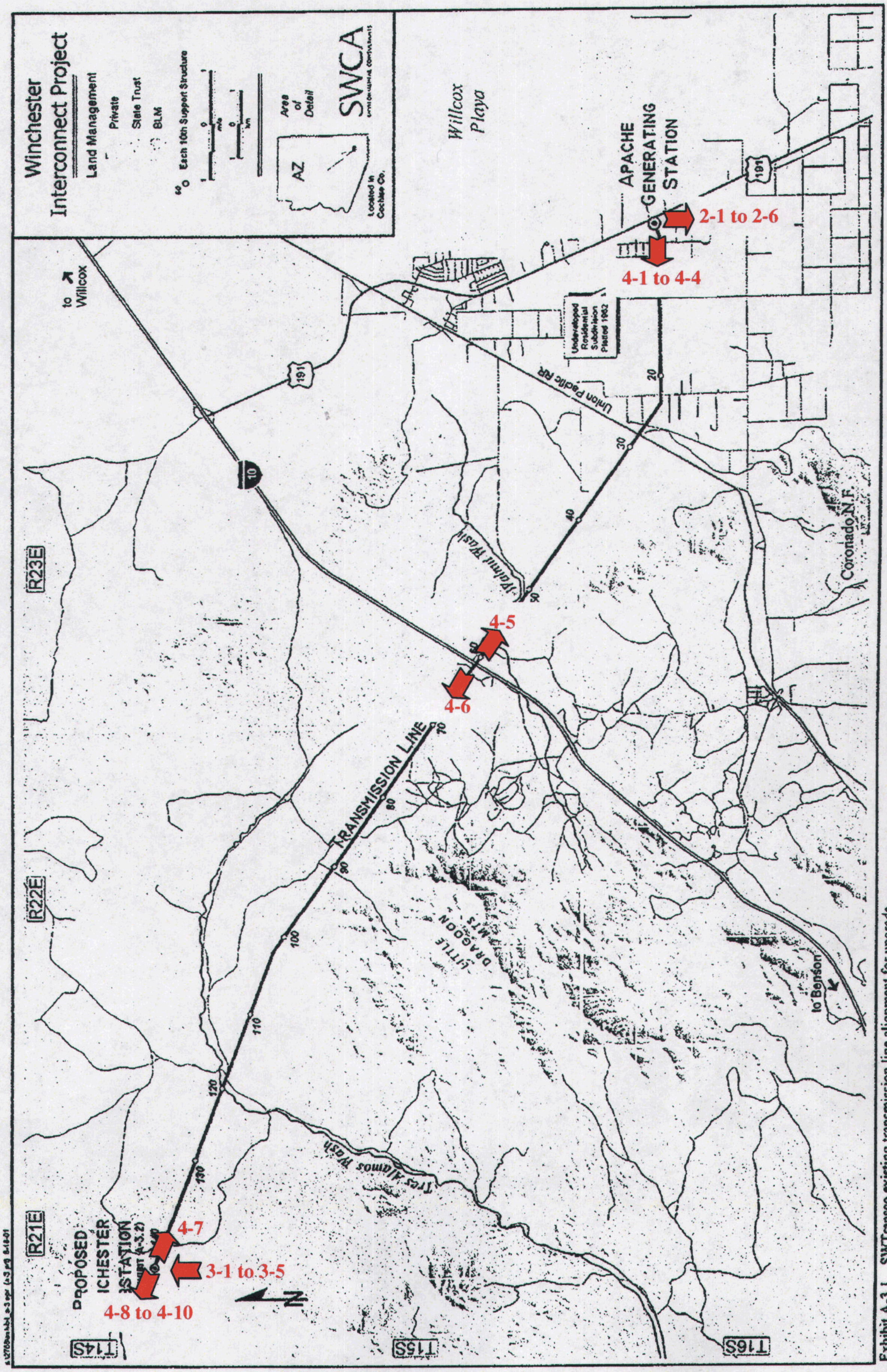

Exhibit A-3.1. SWTransco existing transmission line alignment for upgrade.

EXHIBIT 2
Apache Substation

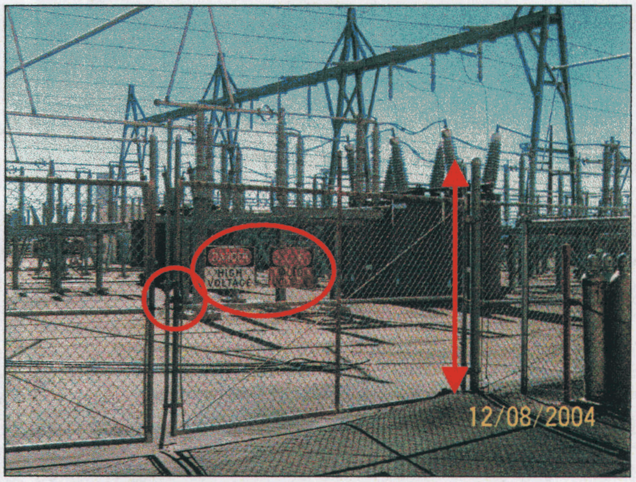

Figure 2-1. Gate and Fence

Figure 2-2. Signage

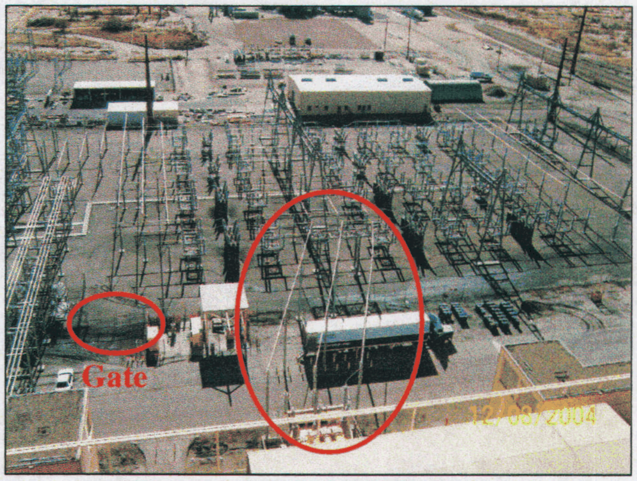

Figure 2-3. 230 kV Switchyard

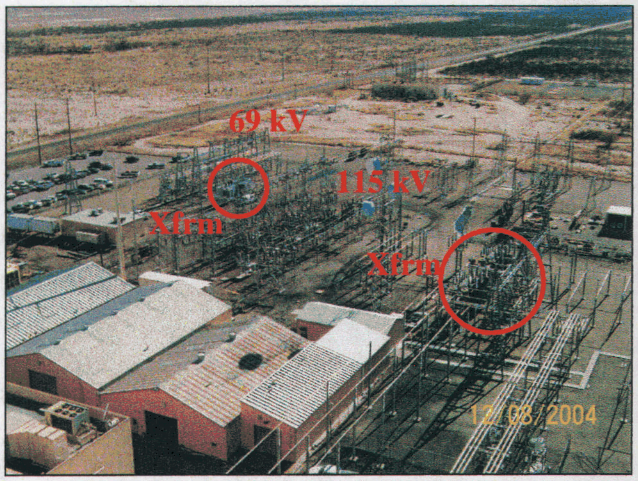

Figure 2-4. 115 kV & 69 kV Switchyards

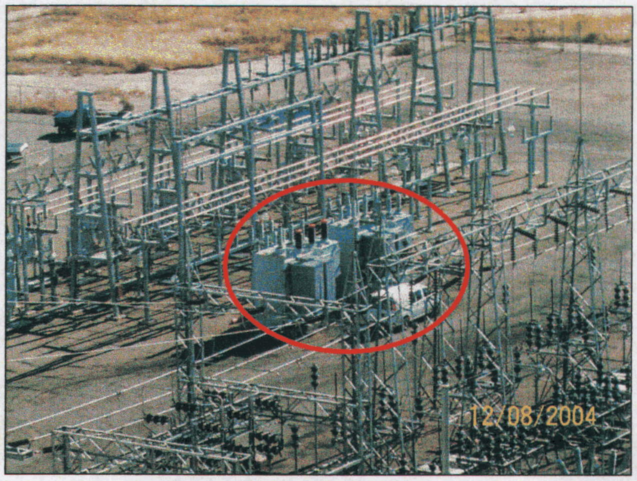

Figure 2-5. 115/69 kV Transformers

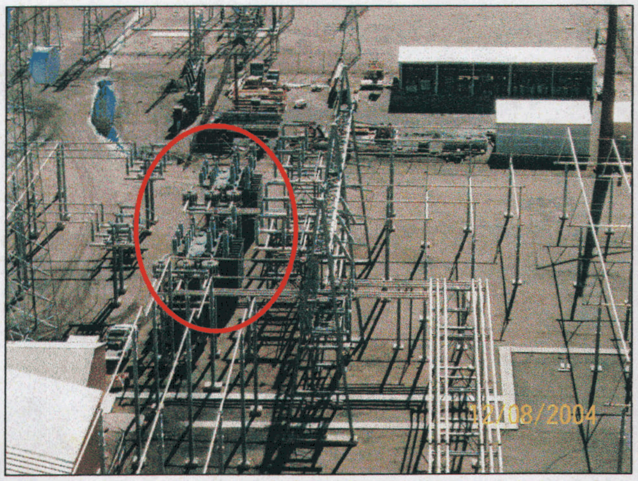

Figure 2-6. 230/115 kV Transformers

EXHIBIT 3
Winchester Substation

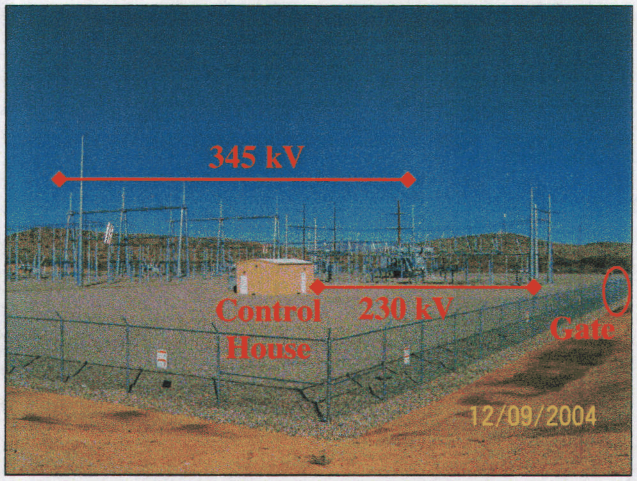

Figure 3-1. Winchester Site and Fencing

Figure 3-2. Gate and Signage

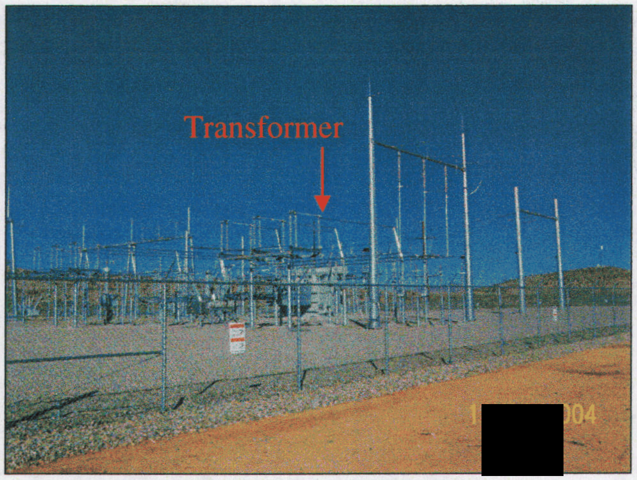

Figure 3-3. 230 kV Switchyard

Figure 3-4. SCADA and Relays

Figure 3-5. 345/230 kV Transformer Nameplate

EXHIBIT 4
Apache to Winchester 230 kV Line

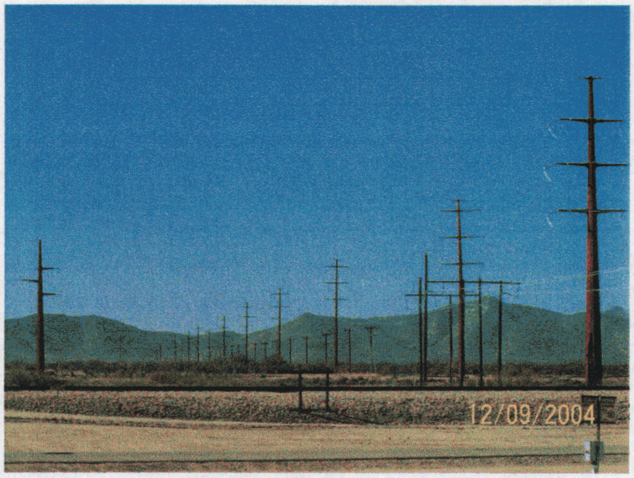

Figure 4-1. Westerly Egress from Apache

Figure 4-2 Railroad Crossings at Apache

Figure 4-3. Westerly 230 kV Corridor at Apache

Figure 4-4. 230 kV Corridor West of Apache

Figure 4-5. 230 kV Line SE of I-10 Crossing

Figure 4-6. 230 kV Line NW of I-10 Crossing

(EXHIBIT 4 continued)

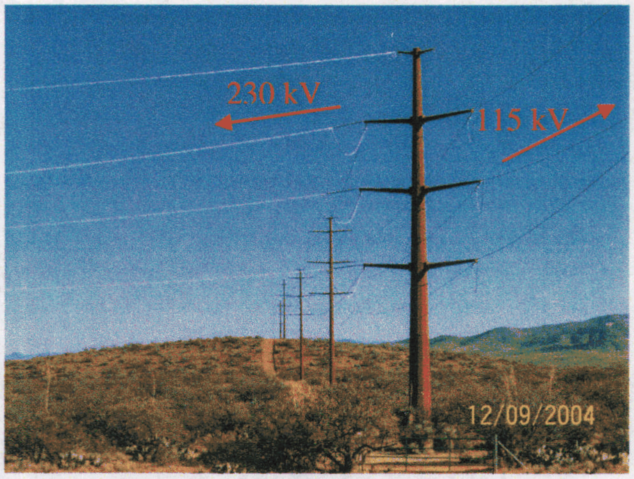

Figure 4-7. Southerly 230 kV Winchester Ingress Egress

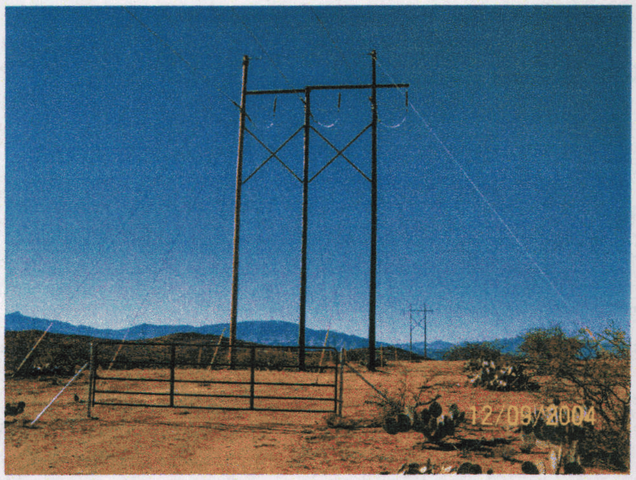

Figure 4-8. Northerly 115 kV Winchester

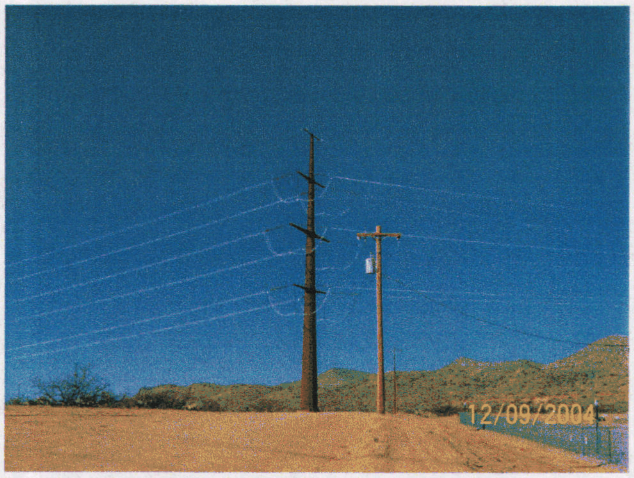

Figure 4-9. NE 345 kV Winchester Ingress

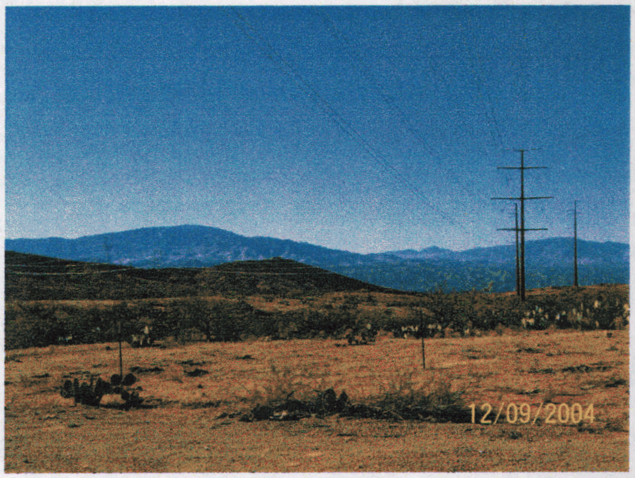

Figure 4-10. NW 345 kV Winchester Egress