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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
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COMMISSIONERS
KRISTIN K. MAYES - Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR 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-09-0472 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Ralph C. Smith and Randall Vickroy of the Utilities' Division in the above docket. An Unredacted version of Ralph C. Smith's Direct Testimony has also been provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 2nd day of July 2010.

Maureen A. Scott, Senior Staff Counsel
Ayesha Vohra, Attorney
Legal Division
Arizona Corporation Commission
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Original and thirteen (13) copies of the foregoing filed this 2nd day of July 2010 with:

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Arizona Corporation Commission
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BEFORE THE ARIZONA CORPORATION COMMISSION

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GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF THE 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-09-0472

DIRECT

TESTIMONY

OF

RALPH C. SMITH

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 02, 2010

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ATTACHMENTS

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-09-0472

My testimony and Attachment RCS-2 present Staff's recommended rate base, net income (margin) and revenue increase for Arizona Electric Power Cooperative, Inc. ("AEPCO"). In computing Staff's recommended revenue increase, I used the debt service coverage ("DSC") method and applied the DSC ratio of 1.40 recommended by Staff witness Vickroy.

Staff's recommended rate base is $211.8 million versus the $231.8 million requested by AEPCO. The following table summarizes Staff's recommended rate base adjustments:

Summary of Staff Adjustments to Rate Base			
Adj. No.	Description		Increase (Decrease)
B-1	Plant Held for Future Use	$	(2,551,631)
B-2	Acquisition Adjustment	$	-
B-3	Accumulated Depreciation - Retirement Work in Progress	$	(3,547,307)
B-4	Fuel Stock	$	-
B-5	Deferred Debits	$	(12,850,764)
B-6	Asset Retirement Obligation	$	(1,092,679)
	Total of Staff Adjustments	**$**	**(20,042,381)**
	AEPCO Proposed Rate Base (Original Cost)	$	231,844,975
	Staff Proposed Rate Base (Original Cost)	**$**	**211,802,594**

Both AEPCO and Staff have used original cost information to derive the fair value rate base. Because AEPCO is a cooperative, a DSC method is being used to derive the recommended revenue requirement, and the revenue requirement does not vary with the amount of rate base.

Staff's adjustments produce an adjusted net income (margin) of $5.232 million versus the $3.333 million proposed by AEPCO. Staff's recommended adjustments to income are summarized in the following table:

Summary of Staff Adjustments to Net Income (Margin)		**Net Income (Margin)**	
Adj. No.	**Description**		**Increase (Decrease)**
C-1	Work Force Reduction	$	898,760
C-2	Incentive Compensation	$	681,900
C-3	Donations	$	79,926
C-4	Lobbying Expense in Association Dues	$	112,240
C-5	Asset Retirement Obligation - Depreciation and Accretion Expense	$	125,720
Total of Staff's Adjustments to Net Operating Income		**$**	**1,898,546**
	Adjusted Net Income per AEPCO	$	3,333,347
	Adjusted Net Income per Staff	**$**	**5,231,893**

On Attachment RCS-2, Schedule A, page 1, I present Staff's calculation of the revenue deficiency for AEPCO. As shown on Schedule A, page 1, column D, lines 16-26, using the DSC ratio of 1.40 recommended by Staff witness Vickroy, my calculations show a revenue deficiency of approximately $231,000. As shown on Attachment RCS-2, Schedule C, line 20, this represents an increase of approximately 0.13 percent over adjusted total operating revenues at AEPCO's current rates.

I. INTRODUCTION

A. Background and Qualifications

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 30 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia, Wisconsin, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have previously testified before the Commission on a number of occasions. I most recently testified before the Commission in Docket Nos. W-01303A-09-0343 and SW-01303A-09-0343 involving general rate case requests by Arizona-American Water Company. I testified in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS"), APS' Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, concerning proceedings involving APS base rates and other matters, and the most recent APS case, Docket No. E-01345A-08-0172, concerning an emergency rate increase and general rate case request. I also testified before the Commission in the last UNS Gas, Inc. rate cases, Docket Nos. G-04204A-08-0571, G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, in a previous UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, as well as the last Southwest Gas Corporation rate case, Docket No. G-01551A-07-0504, and Tucson Electric Power Company rate case, Docket No. E-01933A-07-0402, among others. I also submitted direct testimony in Docket No. E-04100A-09-0496, a rate case application by Southwest Transmission Cooperative, Inc.

B. Purpose of Testimony

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the application for a general rate increase filed by Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Company"). Specifically, I will be addressing the revenue requirement, rate base, and net operating income.

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. The information I reviewed included AEPCO's application and testimony, AEPCO's responses to data requests of Staff, information provided to me by Staff, and other publicly available information.

C. Content of Attachments to Testimony

Q. Have you attached any exhibits to be filed with your testimony?

A. Yes. I am attaching two exhibits, Attachments RCS-2 and RCS-3.

Q. What is shown in each of those attachments?

A. Attachment RCS-2 presents the results of my analysis including Staff's recommended revenue requirement, rate base and adjusted net operating income. Attachment RCS-3 presents copies of responses to data requests and selected documents that are referenced in my testimony.

D. General Background to AEPCO's Rate Request

Q. Please briefly provide some background for the request that AEPCO has made in the current proceeding.

A. AEPCO is a non-profit, certificated electric generation cooperative which serves the power needs of its four all-requirements ("ARM") and two partial requirements ("PRM") Class A Member distribution cooperatives. The distribution cooperatives, in turn, use the power supplied by AEPCO to meet the electricity needs of their retail member owners primarily in the rural areas of Arizona.

AEPCO's current base rates became effective September 1, 2005 pursuant to Decision No. 68071, dated August 17, 2005. That case, Docket No. E-01773A-04-0528, used a test year ending December 31, 2003. In Decision No. 68071, the Commission had ordered AEPCO to file a rate case six months after one of its Class A Members, Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC"), completed a full calendar year as a partial-requirements member. In Decision No. 71112, the Commission granted an extension and authorized AEPCO to delay its rate case filing to October 1, 2009 using a test year ending March 31, 2009.

AEPCO filed an application on October 1, 2009 using a test year ending March 31, 2009. In that application, AEPCO requested, among other things, a revenue increase of approximately $4.023 million or a 2.41 percent increase in revenue requirements. The net increase proposed by AEPCO was a blend of a 2.83 percent <u>decrease</u> in the revenues from rates from its ARMs and a 5.39 percent <u>increase</u> in the revenues from its PRMs.[1] AEPCO's filing was intended to produce a Debt Service Coverage ("DSC") Ratio of 1.35 and operating margins of approximately $3.4 million.[2]

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[1] See, e.g., Direct Testimony of AEPCO witness Gary Pierson, filed October 1, 2009, at page 2, lines 16-19.
[2] See, AEPCO, October 1, 2009 Application, at page 2, lines 3-4.

After discussions with its members and with Staff, AEPCO and its members reported that they had reached agreement on many of the issues in the rate case and would be filing revisions to the application. AEPCO filed Amended and Restated R14-2-103.B Schedules in support of its application for general rate relief with the Commission on April 20, 2010. In that revised application, AEPCO requests a net decrease in revenues of approximately $97,000 using a test year ending March 31, 2009, and a DSC of approximately 1.28.

II. REVENUE REQUIREMENT

A. Summary of AEPCO's Requested Decrease

Q. Please briefly summarize AEPCO's basis for its request for a rate decrease.

A. Using a test year ending March 31, 2009, with pro forma adjustments, AEPCO is seeking a base rate decrease of $97,000, or approximately 0.06% below AEPCO's adjusted test year electric revenue.[3] AEPCO's requested revenue is designed to produce a net margin of approximately $3.237 million, a Times Interest Earned Ratio ("TIER") of 1.30 and a DSC of approximately 1.28.[4] Consistent with its October 1, 2009 application, AEPCO has continued to request that the rates in its general rate application become effective on January 1, 2011.

Q. What is causing AEPCO's request for a revenue decrease of approximately $97,000, considering that actual test year net income only was almost $15.8 million?

A. Events occurring after the test year included higher delivered prices for coal costs as the result of new coal contracts that became effective January 1, 2009 and post-test year revenue losses through January 1, 2011. AEPCO's actual recorded results for the test year ended March 31, 2009, as summarized on Attachment RCS-2, Schedule A, column A, line 7, indicate a positive net income of approximately $15.8 million. This would indicate a

[3] AEPCO's April 30, 2010 Amended and Restated Application, Schedule A-1.
[4] Id., at Schedule A-2, "Proposed Rates" column.

significant base rate revenue decrease would be in order, but for the Company's pro forma adjustments. As explained in AEPCO witness Minson's October 1, 2009 direct testimony at pages 7-8:

> *". . . generally there are four primary cost changes which are driving the need for this request.*
>
> *First, our long-term coal arrangements expired at the end of last year and we are seeing much higher delivered coal costs as a result of the new coal contracts which became effective January 1, 2009. AEPCO's 2008 delivered cost of coal was approximately $1.90/MMBtu in 2008, but that has risen to about $3.00/MMBtu this year. Second, this rate application reflects substantial impacts to both AEPCO's cost and revenues as a result of (a) the expiration of the City of Mesa ("Mesa") 15 MW sales agreement on December 31, 2008; (b) the expiration of the Public Service Company of New Mexico ("PNM") 13 MW purchased power agreement on December 31, 2008; but, most significantly, (c) the expiration of the 100 MW Salt River Project ("SRP") 20-year sales contract on December 31, 2010. Third, most of our generating assets at Apache are now 30 or more years old. Although the embedded costs associated with that plant are comparatively very low, as the units age, the overhaul and maintenance costs associated with them are increasing. Finally, in order to meet the mercury control requirements of the Consent Order with the Arizona Department of Environmental Quality, AEPCO will incur significant increased costs starting in January 2011 to inject certain chemicals into the Apache Station coal-fired units combustion process.[5] AEPCO has made a pro forma adjustment to reflect the costs of those chemicals. As Mr. Pierson explains in his testimony, the overall impact of these and other adjustments on net margins is a <u>decrease</u> of more than $15 million."*

The estimated impact of AEPCO's proposed pro forma adjustments on its margins and revenue requirement is shown in the following table:

[5] It should be noted that AEPCO pro forma adjustment #11, Mercury Control Adjustment, that had been in the Company's October 1, 2001 filing, was removed from its base rate revenue requirement increase request when AEPCO filed its amended and restated application on April 20, 2010.

Description	AEPCO Adj. No.	Impact on Income (A)	Impact on Revenue Requirement (B)
I. AEPCO's Proposed Pro Forma Adjustments			
Coal Cost Adjustment	1	$ (14,946,695)	$ 14,946,695
Payroll & Pension Adjustments	2	$ (1,472,532)	$ 1,472,532
SRP Contract Expiration Adjustment	3	$ (13,210,326)	$ 13,210,326
City Of Mesa Contract Expir. Adjustment	4	$ (2,271,204)	$ 2,271,204
PRP PPA Contract Expir. Adjustment	5	$ 4,712,636	$ (4,712,636)
MEC Add. Sales Adjustment	6	$ 5,303,853	$ (5,303,853)
SSVEC Add. Sales Adjustment	7	$ 3,973,995	$ (3,973,995)
Arm Coal & Purchased Power Adjustment	8	$ 6,464,788	$ (6,464,788)
Maintenance Outage Adjustment	9	$ (2,129,298)	$ 2,129,298
SAP Software Amortization Adjustment	10	$ (824,755)	$ 824,755
Mercury Control Adjustment	11	$ -	$ -
Southpoint PPA Capacity Adjustment	12	$ 232,500	$ (232,500)
Rate Case Amortization Adjustment	13	$ (160,000)	$ 160,000
Interest Adjustment	14	$ (231,437)	$ 231,437
Revenue Synchronization Adjustment	15	$ 2,057,807	$ (2,057,807)
Totals		$ (12,500,668)	$ 12,500,668

The revenue loss and cost impacts resulting from the Salt River Project contract commence on January 1, 2011. AEPCO has indicated that is why it is requesting the new rates not take effect until that date.

As shown on Schedule A, page 2, lines 16-18, AEPCO's requested revenue decrease of $96,754 can be shown to consist of the difference between: (1) its pro forma adjusted test year net margin of approximately $3.333 million and (2) AEPCO's requested coverage requirement of approximately $3.237 million.

Q. Has AEPCO presented reconstructed cost new less depreciation ("RCND") information in its filing for determining the amount of fair value rate base?

A. No. The October 1, 2009 direct testimony of AEPCO witness Gary Pierson states at page 6, lines 19-21 that Schedules B-3 and B-4, concerning RCND rate base, were not completed and "[a]s a non-profit cooperative, AEPCO stipulates to the use of its original cost rate base as its fair value rate base."

Q. Has Staff also used AEPCO's original cost information for determining the amount of fair value rate base?

A. Yes.

B. Summary of Staff's Recommendation

Q. What revenue increase does Staff recommend?

A. Staff recommends a base rate revenue increase of approximately $231,000.

Q. What calculations have you presented in support of that recommendation?

A. On Attachment RCS-2, Schedule A, page 1, I present a calculation of the revenue deficiency for AEPCO. As shown on Schedule A, page 1, column C, my calculations show a revenue deficiency of approximately $231,000. As shown on Attachment RCS-2, Schedule C, line 20, this represents an increase over current operating revenues of approximately 0.13 percent.

C. Test Year

Q. What test year is being used in this case?

A. AEPCO's filing is based on the historic test year ended March 31, 2009. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Rate base items that tend to fluctuate from month to month, such as materials and supplies and fuel stock, are based on a test year average level.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will typically increase as new plant is added to serve new customers, revenue will change as existing contracts expire or new ones are added, expenses will fluctuate etc. It is important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted. For example, it would be inappropriate and unbalanced to recognize only increases to labor expense occurring beyond the test year, and to ignore offsetting known and measureable decreases to labor cost.

D. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-6 and net operating income adjustment Schedules C-1 through C-5. The revenue requirement for AEPCO was based upon the ACC jurisdictional adjusted results.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony, as well as the recommended DSC coverage recommended on behalf of Staff by Randall Vickroy of Liberty Consulting. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to achieve Staff's recommended coverage.

Q. What is shown in each column of Schedule A, page 1?

A. Column A shows AEPCO's actual unadjusted test year results. Those actual results show that for the 12 months ending March 31, 2009, AEPCO had net margins of approximately \$15.8 million. To achieve a TIER of 1.305894, based on the test year <u>unadjusted</u> results for AEPCO, a base rate revenue reduction of approximately \$12.5 million would be in order.

Column B presents AEPCO's proposed test year adjusted results. This reflects the impact of the pro forma adjustments proposed by AEPCO. As shown on line 7, AEPCO's adjusted results show a positive net margin of approximately \$3.3 million. This equates to a TIER of 1.308295 and a DSC of approximately 1.28.

As shown in column C, the Cooperative's pro forma adjusted results were used by AEPCO to derive its proposed revenue decrease of approximately \$97,000 to produce its requested TIER of 1.305894 and a DSC of approximately 1.28.

Column D shows the test year adjusted results per Staff.

Column E shows the derivation of the amount of rate increase using Staff's adjusted test year operating results and Staff's recommended coverage.

Q. What is shown in each section of Attachment RCS-2, Schedule A, page 1?

A. Section I of Schedule A shows the derivation of AEPCO's net operating income. Section II shows the derivation of the revenue increase using a TIER basis. Section III shows the derivation of the revenue increase using a DSC basis. Both the TIER and DSC method of deriving a utility's revenue requirement are considered cash methods (as opposed to the rate base/rate of return method that is typically used for investor-owned utilities). Section IV shows the components of the return and the return on rate base produced by the recommended revenue increase.

A DSC ratio of 1.40[6] will result in a required operating income of $16,275,101. This equates to a 7.68 percent rate of return on Staff's adjusted Fair Value Rate Base of $211,802,594, as shown on Attachment RCS-2, Schedule A, column E, lines 32-34.

Q. How does the recommended DSC affect the amount of net income?

A. As shown on Schedule A, page 1, because Staff witness Vickroy has recommended a higher DSC than was requested by AEPCO, this produces a higher amount of required net income under Staff's recommendation.

Q. What is shown on Schedule B?

A. Schedule B presents AEPCO's proposed adjusted test year Original Cost and Staff's proposed adjusted test year Original Cost rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically

[6] This DSC equates to a TIER of 1.505254.

AEPCO Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is AEPCO's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to AEPCO's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of these adjustments is discussed in my testimony.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by AEPCO and the capital structure and cost of capital that is recommended by Staff witness Vickroy.

Q. Which schedules in Attachment RCS-2 show the rate base and operating income adjustments?

A. Schedules B-1 through B-6 provide further support and calculations for the rate base adjustments Staff is recommending. Schedules C-1 through C-5 provide further support and calculations for the net operating income adjustments Staff is recommending.

III. RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Attachment RCS-2, Schedule B. The adjustments to AEPCO's proposed rate base are summarized on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost is presented below:

Summary of Staff Adjustments to Rate Base

Adj. No.	Description		Increase (Decrease)
B-1	Plant Held for Future Use	$	(2,551,631)
B-2	Acquisition Adjustment	$	-
B-3	Accumulated Depreciation - Retirement Work in Progress	$	(3,547,307)
B-4	Fuel Stock	$	-
B-5	Deferred Debits	$	(12,850,764)
B-6	Asset Retirement Obligation	$	(1,092,679)
	Total of Staff Adjustments	**$**	**(20,042,381)**
	AEPCO Proposed Rate Base (Original Cost)	$	231,844,975
	Staff Proposed Rate Base (Original Cost)	**$**	**211,802,594**

As noted above, both AEPCO and Staff are using the original cost rate base as the fair value rate base in this case.

Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this situation, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. What has AEPCO proposed for Cash Working Capital?

A. AEPCO has proposed a zero amount for Cash Working Capital because it did not prepare a lead-lag study.[7]

Q. For purposes of this rate case, does Staff agree with the use of a zero amount for Cash Working Capital?

A. Yes. Since AEPCO did not prepare a lead-lag study, a zero amount should be used for Cash Working Capital.

Prepayments

Q. How has AEPCO treated Prepayments for purposes of rate base?

A. AEPCO has excluded Prepayments from rate base because of the position taken by Staff in its 2004-2005 rate case.[8]

Q. Does Staff agree that Prepayments should be excluded from rate base in the current AEPCO rate case?

A. Yes. AEPCO's exclusion of Prepayments from rate base is consistent with the position taken by Staff in AEPCO's and SWTC's previous rate cases. For example, in Docket No. E-01773A-04-0528, Staff pointed out that the cooperatives failed to conduct a lead-lag study, thus omitting a major component of Working Capital, which could decrease rate

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[7] See, e.g., AEPCO's filing at Schedule B-5, page 2, and the October 1, 2009 direct testimony of AEPCO witness Gary Pierson at page 7, lines 4-6.
[8] Id., lines 6-8.

base due to the long lags applied to significant expenses such as property taxes and interest. Additionally, Staff noted that in Decision No. 58405, the Commission removed prepayments. Consequently, Staff concurs with AEPCO's exclusion of Prepayments from rate base in the current AEPCO rate case.

AEPCO-Proposed Rate Base Adjustments

Q. Did AEPCO propose any pro forma adjustments to rate base in the current AEPCO rate case?

A. No.[9]

Staff Rate Base Adjustments

Q. Is Staff proposing any adjustments to rate base that were not made by AEPCO?

A. Yes. Staff's recommended adjustments to rate base are discussed below.

B-1. Plant Held for Future Use

Q. Please discuss the adjustment to remove Plant Held for Future Use ("PHFFU") from rate base.

A. AEPCO included $2,551,631 for PHFFU in rate base. As explained by AEPCO in its response to data request STF 1-71:

> *A parcel of land was purchased in 2004 for the future site of an office complex. The carrying value of this parcel is $2,538,392.31. At this time there are no plans to begin construction of the office complex*

As explained in AEPCO's response to data request STF 2-11, AEPCO also inadvertently included $13,238 in PHFFU related to an acquisition adjustment that has been fully amortized. Although AEPCO's response to data request STF 2-11 indicates that this

[9] See, e.g., AEPCO Schedule B-1, and the direct testimony of Gary Pierson at page 6, lines 18.

acquisition adjustment has now been fully amortized, and thus had no rate base impact, AEPCO's Schedule B-1, at line 7, included the full $2,551,631 amount in rate base.

Q. Please summarize Staff's recommendation.

A. The PHFFU should be removed from rate base. AEPCO has no current plans to begin construction of the office complex on the land it had purchased in 2004 so that land is not used and useful in providing utility service. The acquisition adjustment was included by AEPCO in error in the PHFFU account. This rate base error should be removed. As shown on Attachment RCS-2, Schedule B-1, the $2,551,631 amount that AEPCO included in rate base on its Schedule B-1 should be removed.

B-2. Acquisition Adjustment

Q. Please discuss the Company's Acquisition Adjustment.

A. As described in the response to data request STF 2-11, AEPCO recorded an acquisition adjustment of $13,238 in Account 114. AEPCO's response also indicates that this amount has been fully amortized. However, AEPCO carried this amount into its proposed amount for rate base on its Schedule B-2 and Schedule B-1, by inadvertently including it in the $2,551,631 amount for Plant Held for Future Use. This item has been removed from rate base, as shown on Attachment RCS-2, Schedule B-1, as part of the PHFFU adjustment, described above.

Q. Did Staff remove the acquisition adjustment from rate base in AEPCO's last rate case?

A. Yes. Staff removed this acquisition adjustment from rate base in AEPCO's last rate case, Docket No. E-01773A-04-0528. Additionally, Staff also removed it in the prior rate case to that one, as indicated in Decision No. 65367 (dated November 5, 2002) at page 4, lines 21-24. AEPCO's acquisition adjustment is related to SWTC's acquisition adjustment.

Q. Did AEPCO accept Staff's adjustment to remove the acquisition adjustment from rate base in AEPCO's last rate case?

A. Yes.

Q. Why should the acquisition adjustment be removed from rate base in AEPCO's current rate case?

A. 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. Non-recognition of the acquisition adjustment in rate base is the normal ratemaking treatment. As noted above, this acquisition adjustment was removed in the last AEPCO rate case.

Q. Please summarize Staff's recommendation.

A. The acquisition adjustment that AEPCO recorded in Account 114 should be removed from rate base in AEPCO's current rate case. Because this item has already been removed as part of Staff Adjustment B-1, there is no need for a separate adjustment.

B-3. Accumulated Depreciation – Retirement Work in Progress

Q. What has AEPCO proposed for Accumulated Depreciation?

A. AEPCO proposed using $204,796,249 for Accumulated Depreciation in deriving its rate base, inclusive of the following components:

Components of Accumulated Depreciation in AEPCO's Proposed Rate Base	
Component	**Amount**
Production	$ (194,303,265)
Transmission	$ (1,580,842)
Retirements	$ 3,547,307
General	$ (10,016,425)
Elec Plt In Service	$ -
Accumulated Amortization	$ (2,443,024)
Total	**$ (204,796,249)**
Source: AEPCO filing Schedule E-5	

Q. Is Retirement Work in Progress ("RWIP") normally a component of rate base?

A. No. RWIP 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.

Q. What adjustment does Staff recommend?

A. Staff recommends increasing Accumulated Depreciation by $3,547,307 to remove RWIP from rate base as shown on Attachment RCS-2, Schedule B-3. This adjustment decreases AEPCO proposed rate base by $3,547,307.

B-4. Fuel Stock

Q. How did AEPCO determine the Fuel Stock amount it included in rate base in the current rate case?

A. AEPCO used a 12-month average to determine its proposed Fuel Stock amount of $16,033,459, as shown on AEPCO Amended & Restated Filing, April 20, 2010, Schedule B-5, page 3.

Q. How did Staff determine the Fuel Stock amount in AEPCO's last rate case?

A. Staff used a number of days burn method to determine the average cost of coal inventory, which was the method proposed by AEPCO in its last rate case. The difference between Staff and AEPCO in Docket No. E-0773A-04-0528 related to the application of the number of days burn method, and within that method primarily to Staff's use of a lower quantity of tons per burn day. During April of the calendar 2003 test year used in that case, AEPCO had changed its inventory level target from 5,300 tons per burn day to 4,100 tons, so Staff used the 4,100 ton amount in its recommendation in that case.

Q. Did changes occur during the test year that affect AEPCO's coal inventory?

A. Yes. Increased coal prices resulting from new contracts which took effect on January 1, 2009 have caused increases in the price of delivered coal that are not reflected in the test year average balance. Additionally, as explained in the direct testimony of AEPCO witnesses Minson and Pierson, and in response to data request STF 1.66(a), while making replacement arrangements in 2008 for coal to be delivered after 2008 under new contracts, AEPCO realized that the post-2008 cost of delivered coal would increase significantly both in terms of supplier rates and railroad transportation charges. Accordingly, in 2008, AEPCO developed a strategy to stockpile additional coal under the then-existing contracts to be saved and used in 2009 and 2010. AEPCO's response to data request STF 1.66(a) indicates that, without this stockpile, the impact of increased delivered coal costs would be larger than reflected in AEPCO's pro forma adjustment, which would have resulted in a larger proposed rate increase. Consequently, the average quantities of coal in the inventory for the test year are above normal levels, but AEPCO's stockpiling strategy in anticipation of substantial delivered coal cost increases would likely have saved customers money. AEPCO's fuel procurement is being reviewed by Staff, but that prudence review has not yet been completed.

Q. What Fuel Stock inventory does Staff recommend for purposes of the current AEPCO rate case?

A. For purposes of determining AEPCO's rate base at this stage of the proceeding, Staff has accepted AEPCO's proposed Fuel Stock inventory of approximately $16.033 million as shown on Attachment RCS-2, Schedule B-4, without adjustment. This acceptance is contingent upon the results of Staff's prudence investigation of AEPCO's fuel and purchased power.

B-5. Deferred Debits

Q. What amount of Deferred Debits did AEPCO include in rate base?

A. AEPCO included approximately $12.851 million of Deferred Debits in rate base. This amount is comprised of the following components:

Components of AEPCO's Rate Base Deferred Debit

Account	Description		3/31/09
1830000	Other Deferred Debits (Preliminary Engineering)	$	1,062,320
1830100	Preliminary Surveys	$	76
1831000	SPPR Project #1 - Prefunding	$	145,260
1840000	Overhauls	$	2,775,437
1860000	Misc Deferred Debits	$	-
1861000	Deferred Overhauls - "435" Prior Period	$	1,018,075
1861401	Deferred Overhauls - Steam 1	$	1,430,655
1861402	Deferred Overhauls - Steam 2	$	5,171,744
1861403	Deferred Overhauls - Steam 3	$	903,154
1861404	Deferred Overhauls - Gas Turbine 1	$	61,201
1861405	Deferred Overhauls - Gas Turbine 2	$	6,969
1861406	Deferred Overhauls - Gas Turbine 3	$	105,009
1890000	UnamortLoss/Reacquired Debt	$	170,862
	Total Deferred Debits AEPCO Included in Rate Base	**$**	**12,850,762**

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

A. No, they should not. The Deferred Debits are not generally included in rate base. Staff recommended that Deferred Debits be excluded from rate base in AEPCO's last rate case, Docket No. E-0773A-04-0528, and AEPCO agreed. Additionally, in the 1993 AEPCO rate case preceding that one, Docket No. E-01773A-92-0214, the Commission removed the Deferred Debits from rate base in Decision No. 58405. Consistent with the treatment of these items in the last two AEPCO rate cases, Staff recommends removal of the Deferred Debits from rate base as shown on Attachment RCS-2, Schedule B-5. This reduces AEPCO's proposed rate base by $12.851 million.

B-6. Asset Retirement Obligation

Q. What is an Asset Retirement Obligation?

A. An Asset Retirement Obligation ("ARO") 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) and 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.

Q. Is there a financial accounting statement that addresses ARO accounting?

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

As explained in AEPCO's response to data request STF 1.66(f):

> *SFAS No. 143 requires the recognition of an Asset Retirement Obligation ("ARO"), measured at estimated Fair value, for legal obligations related to decommissioning and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. The initial capitalized asset retirement costs are depreciated over the life of the related asset, with the accretion of the ARO liability classified as an operating expense. See the attached documents.*

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

A. AEPCO's response to data request STF 2-15 shows that AEPCO included a $1,092,679 ARO in Plant as of March 31, 2009. The Cooperative recorded the amount to recognize the present value of its projected retirement cost associated with the retirement of an ash pond.

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.

Q. How did AEPCO reflect the related ARO liability in deriving its proposed rate base?

A. AEPCO did not reflect the related ARO liability as an offset to rate base. As AEPCO explained in its response to data request STF 1.66(e):

> *AEPCO has not included the liability for Asset Retirement Obligations in its rate base because AEPCO is a non-profit cooperative whose revenue requirement is driven primarily by expense coverage and adequate TIER and DSC coverages.*

Q. Is the Commission committed to using financial accounting such as SFAS 143 for 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 $1,092,679 as shown on Attachment RCS-2, Schedule B-6. Staff also recommends no change in the rate-making treatment of retirements with legal obligations.

Q. Is there a related adjustment to operating expenses?

A. Yes. Staff adjustment C-5 removes ARO-related Depreciation Expense and Accretion Expense.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C summarizes Staff's recommended net operating income. Schedule C.1 presents Staff's recommended adjustments to test year revenues and expenses.

Q. Does AEPCO pay income taxes?

A. No. Because AEPCO is a tax-exempt non-profit corporation organized under the provisions of Section 501(c)(12) of the Internal Revenue Code, it does not pay income taxes. Consequently, there is no impact on state and federal income taxes associated with each of the recommended adjustments to operating income.

Q. How does Staff's recommended adjusted net operating income, or margin, compare with AEPCO's request?

A. AEPCO's proposed adjusted test year net operating income is $3.333 million, whereas Staff's recommended adjusted net operating income is $5.232 million.

Each of Staff's recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

AEPCO's Pro Forma Adjustments to Operating Income

Q. Before we discuss Staff's recommended adjustments to operating income, can you briefly review AEPCO's pro forma adjustments?

A. Yes. AEPCO's pro forma adjustments to operating income are summarized on Attachment RCS-2, Schedule A, page 2, on lines 1-15. AEPCO has proposed fourteen pro forma adjustments, which reduce its net income by a total of $12.501 million.

In its April 20, 2010 amended and restated filing, AEPCO withdrew its originally proposed adjustment #11 for increased chemical costs that it projected needing to acquire in order to reduce mercury emissions starting in 2011.

Coal Cost Adjustment. AEPCO's new coal contracts took effect on January 1, 2009. AEPCO adjustment #1 reduced margin by $14.9 million for the impact of the new contracts. This AEPCO adjustment has been accepted, subject to completion of Staff's prudence review.

Labor Cost Increases. AEPCO adjustment #2 increased labor costs and decreased margin by $1.5 million for changes in labor and benefit costs during and subsequent to the test year. This AEPCO adjustment has been accepted subject to making an offsetting adjustment for a known post-test year work force downsizing that is quantified in Staff adjustment C-1.

Lost Revenue Adjustments for Contract Expirations. AEPCO adjustments #3 and #4 reflect lost revenues related to SRP and City of Mesa contract expirations. The City of Mesa contract expired on December 31, 2008. The SRP contract expires on December 31, 2010. Based on the review conducted to date, these AEPCO adjustments have been accepted; however, this is subject to potential refinement or adjustment when Staff completes its rate design analysis. The rate design analysis typically involves a detailed review of existing and proposed revenues from each customer class, and the preparation of a proof of revenues. Consequently, it is possible that concerns about AEPCO's existing revenues may come to light during the rate design analysis that were not apparent during the revenue requirement analysis.

Expiring purchase power contract. AEPCO's contract to purchase power from Public Service of New Mexico ("PNM") expired on December 31, 2008. AEPCO's pro forma adjustment #5 annualized the impact and increased margin by $4.7 million. This adjustment has been accepted subject to completion of Staff's prudence review of AEPCO's fuel and purchased power.

Additional sales from capacity availability. AEPCO's adjustments #6 and #7 reflect increased revenue resulting from sales made to two member cooperatives, Mohave Electric Cooperative, Inc. ("MEC") and SSVEC, respectively, to increase margins by $5.3 million and $3.97 million, respectively. Based on the review conducted to date, these AEPCO adjustments have been accepted subject to potential refinement or adjustment when Staff completes its rate design analysis, as noted above in conjunction with AEPCO proposed adjustments #3 and #4.

Coal and purchased power. AEPCO's pro forma adjustment #8 annualizes the effect of the change in resources, to increase net margins by $6.5 million. AEPCO adjustment #12 reduces Southpoint PPA capacity from 35 to 24 MW to reflect the impact of the SRP, Mesa and PNM contracts expiring, increasing net margin by approximately $232,000. AEPCO adjustment #15 synchronizes revenues with Fuel and Purchased Power Adjustor Clause ("FPPAC") costs from other adjustments, increasing net margin by $2.0 million. These adjustments have been accepted subject to completion of Staff's prudence review of AEPCO fuel and purchased power.

Maintenance Outage Expense. AEPCO's pro forma adjustment #9 amortizes outage expense, increasing margin by $2,129,298. This adjustment has been accepted.

SAP Software Amortization. AEPCO's pro forma adjustment #10 proposes to amortize the Systems Applications Products ("SAP") software at AEPCO over a seven-year period, increasing margin by $824,755. This adjustment has been accepted.

Rate Case Cost. AEPCO's adjustment #13 is for an annual allowance of $160,000 for legal and consultant costs for the current AEPCO rate case. While AEPCO's filing characterizes this as the annual amortization of $480,000 of costs for the rate case application over a three-year period, Staff views the $160,000 as a normalized annual expense allowance amount, not an amortization. AEPCO's response to data request STF 1.52 did not provide the detailed itemization that was sought in that request.[10] This

[10] A copy of AEPCO's response to data request STF 1.52 is included in Attachment RCS-3.

amount has therefore been accepted conditionally, pending receipt of additional detail. Staff is also concerned that the $160,000 requested by AEPCO is double the $80,000 amount of rate case cost requested by the related transmission cooperative, SWTC, yet the filings and many of the issues of these two cooperatives are similar.

Interest Expense Annualization. AEPCO's adjustment #14 annualized interest expense to the end of the test period, reducing net margin by $231,000. AEPCO also adjusted principal payments for the test period to reflect extended maturity dates on certain FFB notes that reduced principal payments by $7.3 million. Staff has accepted AEPCO's adjustment to interest expense and has used the same amount of interest on long-term debt and principal payments for purposes of calculating coverage requirements.

Staff Adjustments to Operating Income

Q. Now will you discuss the adjustments to net operating income that are being recommended by Staff?

A. Yes. Each Staff adjustment to AEPCO's net operating income is discussed below in the order appearing on Attachment RCS-2, Schedule C.1.

C-1. Work Force Reduction

Q. Please explain the adjustment for the significant work force reduction made by AEPCO and its related companies.

A. The response to data request STF 2.31 in SWTC's current rate case, Docket No. E-014100A-9-0496, indicates that AEPCO, SWTC and Sierra have made a reduction in work force of seventeen employees. Moreover, AEPCO calculates that the reduction in force will reduce its labor costs by approximately $898,760 on an annual basis. SWTC provided a confidential attachment to its response to data request STF 2.31 showing details. A copy of that response is also attached for ease of reference in Attachment RCS-3 to my testimony.

Q. What does AEPCO's response to STF 3.1 show?

A. AEPCO's response to data request STF 3.1 shows that AEPCO had identified five material changes from March 31, 2009 through December 31, 2009. It shows that three changes affected test year operating expenses: (1) fuel expense related to new contracts; (2) payroll and pension expense due to wage increases and National Rural Electric Cooperative Association ("NRECA") pension funding requirement increases; and (3) a SAP software capital lease. The response indicates that each of these three changes have in fact been reflected as pro forma adjustments in AEPCO's rate filing in the "C" schedules and are identified there as Coal Price Adjustment, Payroll and Pension Adjustment and SAP Software Amortization Adjustment.

AEPCO's response to data request STF 3.1 states further that changes related to a telephone system capital lease, post-test year plant in service and net debt increases were not included as adjustments because AEPCO believed Staff would not consider such post-test year expenses to be appropriate adjustments.

Q. How has AEPCO requested increases in labor expenses for changes occurring during and subsequent to the test year?

A. For labor costs alone, AEPCO has requested increased expenses of $1,472,532 in its pro forma adjustment #2 for Payroll and RSI Increases.

Q. Should the significant work force change that was identified by SWTC in response to data request STF 2.31 be reflected as pro forma adjustment in setting AEPCO's rates in the current case?

A. Yes, it should. This is a significant change in work force and it significantly impacts AEPCO's proposed labor costs. Reflecting the impact of the work force change would therefore help to mitigate the impact of the other post-test year increases to labor (and other) costs requested by AEPCO. AEPCO's proposed labor costs include the impact of other post-test year changes, but only changes which increased expense (and decreased margin), such as post-test year wage increases that occurred on September 21, 2009 and a post-test year increase in pension costs. To not reflect the offsetting reduction to AEPCO's labor costs related to the known downsizing of the work force would serve to overstate AEPCO's labor cost significantly on a going-forward basis.

Additionally, as noted above, AEPCO's filing includes other significant pro forma adjustments for other items that extend even further beyond the test year ending March 31, 2009, such as changes related to the expiration on December 31, 2010 of AEPCO's sales agreement with SRP.[11]

Q. What is the impact of this adjustment on AEPCO's labor costs and margin?

A. As shown on Attachment RCS-2, this adjustment decreases AEPCO's labor costs by $898,760 and increases margins by a similar amount.

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[11] See, e.g., AEPCO's proposed pro forma adjustment #3 (SRP Contract Expiration Adjustment).

Q. Do you have an alternative recommendation if the Commission does not reflect the impact of the significant post-test year work force decrease on AEPCO's labor costs?

A. Yes. If this adjustment to decrease AEPCO's labor costs for the work force downsizing is not reflected in deriving AEPCO's revenue requirement, alternatively, I would recommend that the other post-test year pro forma adjustments requested by AEPCO, which significantly increased expense (and reduced margins) also be rejected. Rejecting AEPCO's proposed pro forma adjustment #2 for Payroll and Retirement Plan Increases would decrease AEPCO's requested expense by $1,472,532, and would increase margins by a similar amount.

C-2. Incentive Compensation

Q. Does AEPCO have an incentive compensation plan?

A. AEPCO's response to data request STF 1.31(d), (e) and (f) and STF 1.45 provided information concerning AEPCO's incentive compensation. Copies of the relevant incentive program plan documents provided by AEPCO in response to that data request are included in Attachment RCS-3.

Q. What trigger mechanisms are provided for in AEPCO's incentive compensation plan?

A. As shown in the documentation provided by AEPCO in response to STF 1.45, the plan has four trigger mechanisms, which must be met or exceeded by AEPCO to open the program to funding. For the 2008 plan, the four trigger mechanisms were:

1. Positive Operating Margin.
2. Times Interest Earned Ratio ("TIER") of 1.10.
3. Debt Service Coverage Ratio ("DSC") of 1.00.
4. An Equivalent Unplanned Outage Factor ("EUOF"), as defined by IEEE Standard 762, equal to or less than the average EUOF of Steam Units 2 & 3 for the previous full five year period for which data is available. The target EUOF

for the 2008 Incentive Plan is 2.2%, based on the average of years 2002 through 2006.

For the 2009 plan, the four trigger mechanisms were:

1. Positive Operating Margin.
2. Times Interest Earned Ratio ("TIER") of 1.80.
3. Debt Service Coverage Ratio ("DSC") of 1.50.
4. An Equivalent Unplanned Outage Factor ("EUOF"), as defined by IEEE Standard 762, equal to or less than the average EUOF of Steam Units 2 & 3 for the previous full five year period for which data is available. The target EUOF for the 2009 Incentive Plan is 2.2%, based on the average of years 2003 through 2007.

Q. How is the AEPCO incentive plan funded?

A. The AEPCO incentive plan is funded subject to a cap each year that has been approved by the Board of Directors, and is to be funded on a 50/50 split from the savings in actual expenses reduced from those forecast in AEPCO's Budget.[12] Additionally, the plan provides that[13]:

> *All triggers must be satisfied and the achievement with respect to the combined goals must be positive, including provision for funding the program, before the Incentive Plan will be funded. Both AEPCO and SWTC will fund the Incentive Plan proportionately.*

Q. Do these plan provisions raise some concerns about inclusion of the incentive compensation expense in rates?

A. The first three triggers AEPCO had for the 2008 plan appear to be minimal targets that would not reflect adequate financial performance by AEPCO. In contrast with those minimal targets for incentive compensation triggers, AEPCO is seeking, and Staff is recommending, much higher levels in the current rate case.

[12] See, e.g., "Funding Amount" section of AEPCO Incentive Plan documents included in Attachment RCS-3.
[13] See, "Introduction" section of AEPCO Incentive Plan documents included in Attachment RCS-3.

Q. What other aspects of the incentive compensation program raise concerns about including an expense amount for that in operating expenses?

A. The funding of the incentive compensation, as described in the plan documents, is to be based upon a 50/50 split of savings in actual expenses reduced from those forecast in the Budget. AEPCO has not demonstrated that its test year expenses reflect such savings. Consequently, including the incentive compensation expense as an operating expense in determining AEPCO's revenue requirement would be questionable.

Q. How much expense did AEPCO incur in the test year for incentive compensation?

A. AEPCO's response to data request STF 1.45 indicates that AEPCO incurred $681,900 of expense for incentive compensation in the test year. No expense for incentive compensation was incurred in 2009.

Q. Why should incentive compensation expense be removed from test year expenses?

A. In addition to the concerns identified above, there is no assurance that the expense levels included in the test year will be repeated in future years. As noted above, AEPCO's response to data request STF 1.45 indicates there was no expense incurred in 2009.

C-3. Charitable Contributions

Q. Please explain the adjustment to remove Charitable Contributions expense.

A. In response to data request STF 1.24, AEPCO identified $79,926 for Charitable Contributions in the test year. As shown on Schedule C-3, the amounts of $79,926 recorded by AEPCO for such Charitable Contributions are being removed from operating expenses. It is not appropriate to include Charitable Contributions in the cost of service for a public utility because donations are not necessary for the provision of utility service.

C-4. Lobbying in Association Dues

Q. Please explain the adjustment to remove lobbying expense in Association Dues.

A. AEPCO pays dues to various industry associations. Some of those associations engage in lobbying activities. The lobbying activities should be charged below-the-line and excluded from the utility's cost of service. During the test year, four of the industry associations to which AEPCO paid dues were engaged in lobbying and advocacy activities. As described in AEPCO's response to data request STF 1.25, Grand Canyon State Electric Cooperative Association ("GCSECA") estimated that 26 percent of its dues go to lobbying and advocacy activities. The NRECA estimate was 24 percent. Consumers United for Rail Equity ("CURE") estimated 80 percent of dues is for lobbying. The Western Coal Traffic League ("WCTL") estimated 20 percent of its budget is for lobbying. Schedule C-4 shows the amounts of dues paid by AEPCO to these organizations, calculates the amount included in the test year based on the information provided in response to data request STF 1.25, and excludes from test year operating expenses the portion of such dues that are related to lobbying and advocacy activities.

Q. While investigating the inclusion of lobbying costs in association dues, did you discover that one of the dues amounts was overstated for the test year?

A. Yes. An additional adjustment to remove $10,000 for WCTL is necessary based on AEPCO's response to STF 1.25, which stated that:

> *"Actual dues are paid in the amount of $10,000 quarterly. However for the test year, $50,000 was paid, such that anadditional $10,000 was inadvertently included in the test year calculation."*

Q. What is the total impact of this adjustment?

A. As shown on Schedule C-4, test year expense is reduced by $112,240 for the portion of GCSECA, NRECA, CURE and WCTL dues related to lobbying, and for AEPCO's inadvertent over-inclusion of an extra $10,000 in the test year for WCTL dues. AEPCO's margin is increased by the same amount of the expense reduction, $112,240.

C-5. Asset Retirement Obligation-Related Expenses

Q. Please explain Staff adjustment C-5.

A. As shown on Attachment RCS-2, Schedule C-5, this adjustment removes $30,536 of Depreciation Expense and $95,184 of Accretion Expense[14], related to AEPCO's accounting for an ARO related to a coal plant ash pond. As previously discussed in conjunction with Staff rate base adjustment B-6, AEPCO has no investment in the ARO asset; consequently, there is no asset cost to be recovered through depreciation. The ARO-related depreciation and accretion expenses are accounting entries that resulted from AEPCO implementing SFAS 143 for financial reporting purposes. In AEPCO's prior rate case, Docket No. E-01773A-04-0528, Staff recommended the removal of the ARO-related depreciation and accretion expense. The removal of these ARO-related expenses in the current case reflects similar removal treatment for ratemaking purposes. In total, operating expense is reduced by $125,720, and net margin increases by that amount.

[14] Accretion Expense is a type of interest expense that is added to the ARO liability annually to account for the time value of money.

Coal Transportation Legal Expenses

Q. Are there any other matters you wish to address as a result of your review of AEPCO's operating expenses?

A. Yes. I would like to address information obtained during the review of AEPCO's operating expenses concerning AEPCO's legal expenses relating to coal transportation issues.

Q. How has AEPCO been pursuing litigation against a railroad relating to the transportation of coal to the Apache Station?

A. As explained in the responses to data request STF 1-64(b) and 1-38(b), AEPCO has been pursuing litigation against BNSF Railway ("BNSF") before the Surface Transportation Board ("STB") relating to the transportation of coal to the Apache Station.

Q. Has AEPCO sought assistance from other utilities in sharing its litigation costs?

A. No. AEPCO's response to data request STF 1-64(b) explains that AEPCO has not sought assistance from other utilities to share in the litigation cost because AEPCO's case before the STB is a matter that concerns only AEPCO and its specific coal and transportation issues. If AEPCO is successful in its STB rate case against BNSF, AEPCO is the only party that will benefit.

Q. Has AEPCO provided a copy of its claim against the railroad?

A. Yes. In response to data request STF 1-64(c), AEPCO provided its claim and four subsequent amendments thereto.

Q. In what other coal transportation litigation is AEPCO involved?

A. AEPCO is also involved in a dispute with Union Pacific Railroad ("UP").

Q. What amount of expense did AEPCO incur in the test year for legal and consulting fees related to matters involving railroad rates and disputes related to the transportation of coal to the Apache Station?

A. AEPCO's response to data request STF 1-38(b) indicates that AEPCO incurred $538,000 for such matters in the test year. AEPCO's supplemental response to data request STF 1-64(a) indicates that these expenses are recorded in account 5300700.

Q. How does that amount compare with AEPCO's expense for similar activities in other years?

A. These costs are listed by year in response to AEPCO's supplemental responses to data requests STF 1-38 and STF 1-64, and have varied widely from year-to-year, from a low of $38,100 in 2006 to a high of $2.8 million in 2009. AEPCO's response to data request STF 2-21 indicates that AEPCO's six month projection for February through July 2010 are $240,000 for legal costs and $590,000 for consulting and other expenses. AEPCO's response to data request STF 2-18 list amounts separately for 2008, 2009 and January 2010 for the STB rate case against BNSF and for the district court lawsuit against UP. AEPCO's test year amount is lower than the actual amount incurred in 2009 and AEPCO's 2010 projection, and is well within the range of AEPCO's expense for similar activities in other years.

Q. How does AEPCO's response to a Staff data request summarize the nature of the litigation that AEPCO is pursuing against the railroads involved in the transportation of coal to the Apache Station?

A. AEPCO's response to data request STF 2-19 provides the following brief summary:

> *AEPCO is in the process of seeking regulatory relief from coal transportation rates imposed by the BNSF Railway (BNSF) and the*

> *Union Pacific Railroad (UP) through the Surface Transportation Board's (STB) Stand Alone Cost Railroad process. This case was filed in December 2008 with opening evidence and argument submitted by AEPCO January 25, 2010. The railroad's reply case is due in May 2010.*
>
> *AEPCO is also involved in litigation with the UP. UP filed a complaint in January 2009 in U.S. District Court against AEPCO. This complaint alleges that AEPCO refuses to recognize a contract for coal transportation from Colorado and Wyoming coal sources. AEPCO contends that no contract was signed and does not exist. This case continues pending settlement discussions.*
>
> *AEPCO is not involved in any dispute or litigation with the coal suppliers.*

Q. How has AEPCO described the status of any settlement discussions in these matters?

A. AEPCO's response to data request STF 2-20 provides the following summary of settlement discussion status:

> *AEPCO has been involved in settlement discussions with both the Union Pacific Railroad (UP) and the BNSF Railway (BNSF). AEPCO is currently engaged in settlement discussions with the UP. While settlement proposals were exchanged between AEPCO and the BNSF, these proposals were rejected by both parties and AEPCO and the BNSF are not currently engaged in settlement discussions.*

Q. Is Staff proposing any adjustment for AEPCO's "coal transportation legal expenses"?

A. Not at this time. AEPCO's test year amount is well within the range of AEPCO's expense for similar activities in other years, and Staff's prudence review of AEPCO's fuel and purchase power procurement, which should include a detailed review of the related coal transportation litigation AEPCO has engaged in with the railroads, has not yet been completed.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)

80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)

R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)

R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)

GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)

Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)

U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)

03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
Docket No. 09-0319	Illinois-American Water Company (Illinois Commerce Commission)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company
09-0872-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company (Ohio PUC)

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-09-0472
Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

Arizona Electric Power Cooperative, Inc.
Computation of Increase in Gross Revenue Requiremei

Docket No. E-01773A-09-0472
Schedule A
Page 1 of 2

Test Year Ended March 31, 2009

Line No.	Description	Reference	Per AEPCO Test Year Actual (A)	Per AEPCO Test Year Adjusted (B)	Per AEPCO Proposed Rates (C)	Per Staff Test Year Adjusted (D)	Per Staff Proposed Rates (E)
	I. Net Income Summary						
1	Gross Revenue		$ 209,981,784	$ 178,762,679	$ 178,665,925	$ 178,762,679	$ 178,993,693
2	Operating Expenses		$ 183,767,165	$ 164,623,661	$ 164,623,661	$ 162,820,299	$ 162,820,299
3	Electric Operating Income (Margins)	L1 - L2	$ 26,214,619	$ 14,139,018	$ 14,042,264	$ 15,942,380	$ 16,173,394
4	Total Interest & Other Deductions		$ 11,325,919	$ 11,917,826	$ 11,917,826	$ 11,822,642	$ 11,822,642
5	Total Other Non Operating Income		$ 945,315	$ 1,112,155	$ 1,112,155	$ 1,112,155	$ 1,112,155
6	Extraordinary Items		$ -	$ -	$ -	$ -	$ -
7	Net Income (Margins)	L3-L4+L5&6	$ 15,834,015	$ 3,333,347	$ 3,236,593	$ 5,231,893	$ 5,462,907
	II. Times Total Interest Earned (TIER)						
8	Net Income Margins (Loss)	Line 7	$ 15,834,015	$ 3,333,347	$ 3,236,593	$ 5,231,893	$ 5,462,907
9	Interest on Long Term Debt	Note A	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
10	Sum of Margin and Interest on LTD	L8 + L9	$ 26,646,209	$ 14,145,541	$ 14,048,787	$ 16,044,087	$ 16,275,101
11	Interest on Long Term Debt	L9	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
12	TIER Achieved	L10 / L11	2.464459	1.308295	1.305894	1.483888	1.505254
13	Required TIER	Note B	1.305894	1.305894	1.305894	1.505254	1.505254
14	Increased (Decreased) Coverage Needed	L13 - L12	-1.158565	-0.002401	0.000000	0.021366	0.000000
15	Increased (Decreased) Revenue Needed	L14 x L9	$ (12,526,627)	$ (25,959)	$ -	$ 231,014	$ -
	III. Debt Service Coverage (DSC)						
16	Net Income Margins (Loss)	Line 7		$ 3,333,347	$ 3,236,593	$ 5,231,893	$ 5,462,907
17	Interest on Long Term Debt	L9		$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
18	Depreciation & Amortization	Sch C		$ 8,348,168	$ 8,348,168	$ 8,317,632	$ 8,317,632
19	Sum of Above			$ 22,493,709	$ 22,396,955	$ 24,361,719	$ 24,592,733
20	Interest on Long Term Debt	Line 9		$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
21	Principal Payments	Note C		$ 6,754,044	$ 6,754,044	$ 6,754,044	$ 6,754,044
22	Debt Service			$ 17,566,238	$ 17,566,238	$ 17,566,238	$ 17,566,238
23	DSC Achieved	L19 / L22		1.2805080	1.2750001	1.3868490	1.4000
24	Required DSC	Note B		1.2842531	1.2842531	1.4000000	1.4000
25	Increased Coverage Needed			0.0037451	0.0093	0.01315103	-
26	Increased (Decreased) Revenue Needed			$ 65,787	$ 163,366	$ 231,014	$ -
27	Revenue Increase Proposed vs TY Adjusted	Line 1 difference			$ (96,754) Note D Col.C - Col.B		$ 231,014 Col.E - Col.D
	IV. Return on Fair Value Rate Base						
28	Net Income	L7			$ 3,236,593		$ 5,462,907
29	Interest on Long Term Debt	L9			$ 10,812,194		$ 10,812,194
30	Sum of Net Income and Interest on LTD				$ 14,048,787		$ 16,275,101
31	Difference				$ (6,523)		
32	Required Electric Operating Margin				$ 14,042,264 Note D		$ 16,275,101
33	Rate Base (Original Cost and FVRB are Same)	Sch B			$ 231,844,975 Note D		$ 211,802,594
34	Return on Fair Value Rate Base	L32 / L33			6.06% Note D		7.68%

Notes and Source
Col.A-C:
L1-7: AEPCO Schedule A-2, Amended and Revised April 20, 2010
For Column B, also see Attachment RCS-2, Schedule C
Col.D:
L1-7: Schedule C, Col. C
Col.E:
L1-7: Schedule C, Col. E
Notes A-D:
A AEPCO from AEPCO Excel file; Staff from Schedule C, line 12
B Derived from AEPCO Excel file for AEPCO Schedule A-2; Staff per witness Vickroy
For AEPCO also see Company Schedule A-2 (Amended and Restated April 20, 2010) which shows DSC of 1.28 at AEPCO proposed rates.
C AEPCO Excel file detail for AEPCO Schedule A-2

Arizona Electric Power Cooperative, Inc.
Components of Increase in Gross Revenue Requirement

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule A
Page 2 of 2

Line No.	Description	AEPCO Adj. No.	Impact on Income (A)	Impact on Revenue Requirement (B)
	I. AEPCO's Proposed Pro Forma Adjustments			
1	Coal Cost Adjustment	1	$ (14,946,695)	$ 14,946,695
2	Payroll & Pension Adjustments	2	$ (1,472,532)	$ 1,472,532
3	SRP Contract Expiration Adjustment	3	$ (13,210,326)	$ 13,210,326
4	City Of Mesa Contract Expir. Adjustment	4	$ (2,271,204)	$ 2,271,204
5	PRP PPA Contract Expir. Adjustment	5	$ 4,712,636	$ (4,712,636)
6	MEC Add. Sales Adjustment	6	$ 5,303,853	$ (5,303,853)
7	SSVEC Add. Sales Adjustment	7	$ 3,973,995	$ (3,973,995)
8	Arm Coal & Purchased Power Adjustment	8	$ 6,464,788	$ (6,464,788)
9	Maintenance Outage Adjustment	9	$ (2,129,298)	$ 2,129,298
10	SAP Software Amortization Adjustment	10	$ (824,755)	$ 824,755
11	Mercury Control Adjustment	11	$ -	$ -
12	Southpoint PPA Capacity Adjustment	12	$ 232,500	$ (232,500)
13	Rate Case Amortization Adjustment	13	$ (160,000)	$ 160,000
14	Interest Adjustment	14	$ (231,437)	$ 231,437
15	Revenue Synchronization Adjustment	15	$ 2,057,807	$ (2,057,807)
16	Totals		$ (12,500,668)	$ 12,500,668
	II. Components of AEPCO's Requested Revenue Increase			
17	Increase in Revenue Requirement from AEPCO Pro Forma Adjustments			$ 12,500,668
18	Test Year Actual Income		$ 15,834,015	$ 15,834,015
19	Adjusted Test Year Income with AEPCO's Pro Forma Adjustments		$ 3,333,347	$ (3,333,347)
20	Increase in Revenue Requirement from AEPCO Income Deficiency			$ (3,333,347)
21	Margin Requirement requested by AEPCO			$ 3,236,593
22	Revenue Increase Requested by AEPCO - Calculated per Above			$ (96,754)
23	Difference			$ -
24	Revenue Increase Requested by AEPCO per Schedule A, page 1			$ (96,754)
	III. Staff's Proposed Adjustments	Staff Adj. No.		
25	Work Force Reduction	C-1	$ 898,760	$ (898,760)
26	Incentive Compensation	C-2	$ 681,900	$ (681,900)
27	Donations	C-3	$ 79,926	$ (79,926)
28	Lobbying Expense in Association Dues	C-4	$ 112,240	$ (112,240)
29	Asset Retirement Obligation - Depreciation and Accretion Expense	C-5	$ 125,720	$ (125,720)
30				
31				
32	Totals		$ 1,898,546	$ (1,898,546)
33	Adjusted Test Year Income with Staff's Pro Forma Adjustments		$ 5,231,893	L19 + L32
	IV. Components of Staff's Recommended Revenue Increase			
34	Increase (Decrease) in Revenue Requirement from Staff Income Deficiency		Line 33	$ (5,231,893)
35	Margin Requirement Recommended by Staff		Schedule A, p.1	$ 5,462,907
36	Revenue Increase Recommended by Staff - Calculated per Above			$ 231,014
37	Difference			$ -
38	Revenue Increase Recommended by Staff per Schedule A, page 1			$ 231,014

Notes and Source
AEPCO Schedule C-2 and Staff Schedule A, page 1

Arizona Electric Power Cooperative, Inc.
Original Cost Adjusted Rate Base

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B
Page 1 of 1

Line No.	Description	Original Cost: As Adjusted by AEPCO (A)	Original Cost: Staff Adjustments (B)	Original Cost: As Adjusted by Staff (C)
1	Gross Utility Plant in Service	$ 399,424,364	$ (1,092,679)	$ 398,331,685
2	Less: Accumulated Depreciation	$ (204,796,249)	$ (3,547,307)	$ (208,343,556)
3	Net Utility Plant in Service	$ 194,628,115	$ (4,639,986)	$ 189,988,129
4	Customer Advances for Construction	$ -	$ -	$ -
5	Contributions in Aid of Construction	$ -	$ -	$ -
6	Allowance for Working Capital - Fuel and M&S	$ 21,814,465	$ -	$ 21,814,465
7	Plant Held for Future Use	$ 2,551,631	$ (2,551,631)	$ -
8	Deferred Debits	$ 12,850,764	$ (12,850,764)	$ -
9	Total Rate Base	$ 231,844,975	$ (20,042,381)	$ 211,802,594

Notes and Source
Col. A: Arizona Electric Power Cooperative, Inc. filing, Schedule B-1, Amended and Resetated April 20, 2010

Arizona Electric Power Cooperative, Inc.
Summary of Rate Base Adjustments

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B.1
Page 1 of 1

Line No.	Description	Staff Adjustments	Plant Held for Future Use B-1	Acquisition Adjustment B-2	Accumulated Depreciation - Retirement Work in Progress B-3	Fuel Stock B-4	Deferred Debits B-5	Asset Retirement Obligation B-6
1	Gross Utility Plant in Service	$ (1,092,679)		$ -				$ (1,092,679)
2	Less: Accumulated Depreciation	$ (3,547,307)			$ (3,547,307)			
3	Net Utility Plant in Service	$ (4,639,986)	$ -	$ -	$ (3,547,307)	$ -	$ -	$ (1,092,679)
4	Customer Advances for Construction	$ -						
5	Contributions in Aid of Construction	$ -						
6	Allowance for Working Capital	$ -				$ -		
7	Plant Held for Future Use	$ (2,551,631)	$ (2,551,631)					
8	Deferred Debits	$ (12,850,764)					$ (12,850,764)	
9	Total Rate Base	$ (20,042,381)	$ (2,551,631)	$ -	$ (3,547,307)	$ -	$ (12,850,764)	$ (1,092,679)

Arizona Electric Power Cooperative, Inc.
Adjusted Net Operating Income

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C
Page 1 of 1

Line No.	Description	As Adjusted by AEPCO (A)	Staff Adjustments (B)	As Adjusted by Staff (C)	Staff Proposed Changes (D)	Staff Recommended (E)
	Operating Revenues					
1	Class A Revenues	$ 125,199,347	$ -	$ 125,199,347	$ 224,153	$ 125,423,500
2	Fuel Adjustment	$ 41,419,292	$ -	$ 41,419,292		$ 41,419,292
3	Non-Firm, Non-Member, Non-Class A	$ 8,620,097	$ -	$ 8,620,097	$ 6,861	$ 8,626,958
4	Total Electric Revenue	$ 175,238,736	$ -	$ 175,238,736	$ 231,014	$ 175,469,750
5	Other Operating Revenue	$ 3,523,943	$ -	$ 3,523,943		$ 3,523,943
6	**Total Operating Revenue**	$ 178,762,679	$ -	$ 178,762,679	$ 231,014	$ 178,993,693
	Operating Expenses					
7	Operations & Maintenance	$ 153,342,150	$ (1,772,826)	$ 151,569,324		$ 151,569,324
8	Depreciation & Amortization	$ 8,348,168	$ (30,536)	$ 8,317,632		$ 8,317,632
9	Other Taxes	$ 2,933,343	$ -	$ 2,933,343		$ 2,933,343
10	**Total Operating Expenses**	$ 164,623,661	$ (1,803,362)	$ 162,820,299	$ -	$ 162,820,299
11	**Operating Income (Margins)**	$ 14,139,018	$ 1,803,362	$ 15,942,380	$ 231,014	$ 16,173,394
	Interest & Other Deductions					
12	Long-Term Debt	$ 10,812,194	$ -	$ 10,812,194		$ 10,812,194
13	Interest Charged To Constr	$ (187,816)	$ -	$ (187,816)		$ (187,816)
14	Other Interest Expense	$ 1,142,274	$ (95,184)	$ 1,047,090		$ 1,047,090
15	Other Deductions	$ 151,174		$ 151,174		$ 151,174
16	**Total Interest Expense**	$ 11,917,826	$ (95,184)	$ 11,822,642	$ -	$ 11,822,642
17	**Margin After Interest Expense**	$ 2,221,192	$ 1,898,546	$ 4,119,738	$ 231,014	$ 4,350,752
18	Other Nonoperating Income	$ 1,112,155	$ -	$ 1,112,155		$ 1,112,155
19	**Net Income (Margins)**	$ 3,333,347	$ 1,898,546	$ 5,231,893	$ 231,014	$ 5,462,907

Notes and Source
Col. A: Arizona Electric Power Cooperative, Inc. filing, Schedule C-1, pages 3 and 4, Amended and Restated 4/20/2010
Col. B: Staff Schedule C.1
Col.C: Cols. A + B
Col. D, line 4: Staff Schedule A, Column D, line 26

Line	Description	Existing Revenue	Increase	Percent Increase
20	Percentage increase over revenues at current rates, from line 6, Total Operating Revenue	$ 178,762,679	$ 231,014	0.13%

Arizona Electric Power Cooperative, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C.1
Page 1 of 1

Line No.	Description	Staff Adjustments	Work Force Reduction	Incentive Compensation	Donations	Lobbying Expense in Association Dues	Asset Retirement Obligation - Depreciation and Accretion
			C-1	C-2	C-3	C-4	C-5
	Operating Revenues						
1	Class A Revenues	$ -					
2	Fuel Adjustment	$ -					
3	Non-Firm, Non-Member, Non-Class A	$ -					
4	Total Electric Revenue	$ -	$ -	$ -	$ -	$ -	$ -
5	Other Operating Revenue	$ -					
6	**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses:						
7	Operations & Maintenance	$ (1,772,826)	$ (898,760)	$ (681,900)	$ (79,926)	$ (112,240)	
8	Depreciation & Amortization	$ (30,536)					$ (30,536)
9	Other Taxes	$ -					
10	Total Operating Expenses	$ (1,803,362)	$ (898,760)	$ (681,900)	$ (79,926)	$ (112,240)	$ (30,536)
11	Operating Income (Margins)	$ 1,803,362	$ 898,760	$ 681,900	$ 79,926	$ 112,240	$ 30,536
	Interest & Other Deductions:						
12	Long-Term Debt	$ -					
13	Interest Charged To Constr	$ -					
14	Other Interest Expense	$ (95,184)					$ (95,184)
15	Other Deductions	$ -					
16	Total Interest Expense	$ (95,184)	$ -	$ -	$ -	$ -	$ (95,184)
17	Margin After Interest Expense	$ 1,898,546	$ 898,760	$ 681,900	$ 79,926	$ 112,240	$ 125,720
18	Other Nonoperating Income	$ -					$ -
19	Net Income (Margins)	$ 1,898,546	$ 898,760	$ 681,900	$ 79,926	$ 112,240	$ 125,720

Arizona Electric Power Cooperative, Inc.
Capital Structure & Cost Rates

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule D
Page 1 of 1

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Capitalization Debt Only Percent (C)	Cost Rate (D)	Weighted Average Cost of Capital (E)	Annualized Cost With Short Term Debt (F)	Annualized Cost Without Short Term Debt (G)
	I. AEPCO Proposed							
1	Short-Term Debt	$ 15,851,384	5.88%	8.17%	0.350%	0.029%	$ 55,480	
2	Long-Term Debt	$ 178,093,188	66.01%	91.83%	5.570%	5.115%	$ 9,919,791	$ 9,919,791
3	Margins and Equity	$ 75,866,848	28.12%			0.000%	$ -	$ -
4	Total Capital	$ 269,811,420	100.00%	100.00%		5.144%	$ 9,975,271	$ 9,919,791
	II. Staff Proposed							
5	Short-Term Debt	$ 15,851,384	5.88%	8.17%	0.350%	0.029%	$ 55,480 (a)	
6	Long-Term Debt	$ 178,093,188	66.01%	91.83%	5.570%	5.115%	$ 9,919,791 (a)	$ 9,919,791 (a)
7	Margins and Equity	$ 75,866,848	28.12%			0.000%	$ -	$ -
8	Total Capital	$ 269,811,420	100.00%	100.00%		5.144%	$ 9,975,271	$ 9,919,791
9	Difference					0.00%		$ -

Notes and Source

Lines 1-4 taken from Arizona Electric Power Cooperative, Inc. filing, Schedule D-1, Revised Schedule D-2, and AEPCO Schedule A-3, actual test year, 3/31/2009, Amended & Restated, April 20, 2010

Lines 5-8: AEPCO Schedule A-3, actual test year, 3/31/2009, confirmed with Staff witness Randall Vickroy

(a) Staff witness Vickroy is recommending that, prior to determining a final revenue requriement, interest be updated to reflect more current actual information.

For purposes of computing the revenue requirement at this time, the amount of Long Term Debt Interest in AEPCO's pro forma adjusted income statement was used.

Arizona Electric Power Cooperative, Inc.
Plant Held for Future Use

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-1
Page 1 of 1

Line No.	Description	Amount	Reference
1	Plant Held for Future Use	$ (2,551,631)	A&B

Notes and Source

A: AEPCO Filing, Schedule B-1, Line 7 and Schedule E-5, page 2, Line 50
Amended and Restated 4/20/2010

B: AEPCO's responses to STF 1.71 and STF 2-11

Arizona Electric Power Cooperative, Inc.
Acquisition Adjustment

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-2
Page 1 of 1

Line No.	Description	Amount	Reference
1	Remove Acquisition Adjustment from rate base	$ -	A&B

Notes and Source

A: See AEPCO's response to data request STF 2-11. An amount of $13,238 for an Acquisition Adjustment that AEPCO recorded in Account 114 was inadvertently included by AEPCO in rate base as PHFFU and has been removed in Staff Adjustment B-1. Consequently, no additonal adjustment to separately remove the Acquisition Adjustment is necessary in the current case. AEPCO's response also notes that the Acquisition Adjustment has been fully amortized; thus, there should be no related amount for that Acquisition Adjustment included in rate base.

B: Testimony of Staff witness Ralph Smith

Arizona Electric Power Cooperative, Inc.
Accumulated Depreciation - Retirement Work in Progress

Test Year Ended March 31, 2009

Line No.	Description	Amount	Reference
1	Adjust Accumulated Depreciation to remove Retirement Work in Progress from rate base	$ (3,547,307)	A&B

Notes and Source

A: AEPCO Filing, Schedule E-5, page 2 of 4 and Schedule B-2
B: Testimony of Staff witness Ralph Smith

Arizona Electric Power Cooperative, Inc.
Fuel Stock

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-4

Line No.	Month	AEPCO Filed Month-End Balances (A)	AEPCO Adjusted (B)	AEPCO Month-End Balances (C)	Staff Used (D)	Adjustment (E)
1	March (Prior Yr)			$ 12,670,242		
2	April	$ 12,947,499	$ 12,947,499	$ 12,947,499		
3	May	$ 13,052,341	$ 13,052,341	$ 13,052,341		
4	June	$ 12,202,455	$ 12,202,455	$ 12,202,455		
5	July	$ 13,487,043	$ 13,487,043	$ 13,487,043		
6	August	$ 13,527,247	$ 13,527,247	$ 13,527,247		
7	September	$ 13,493,843	$ 13,493,843	$ 13,493,843		
8	October	$ 11,817,432	$ 11,817,432	$ 11,817,432		
9	November	$ 17,387,542	$ 17,387,542	$ 17,387,542		
10	December	$ 19,099,253	$ 19,099,253	$ 19,099,253		
11	January	$ 19,592,846	$ 19,592,846	$ 19,592,846		
12	February	$ 20,512,638	$ 20,512,638	$ 20,512,638		
13	March	$ 25,281,374	$ 25,281,374	$ 25,281,374		
14	Totals	$ 192,401,513	$ 192,401,513	$ 205,071,755		
15	12-Month Average		$ 16,033,459		$ 16,033,459	$ -

Notes and Source

Cols.A and B: AEPCO Amended & Restated Filing, April 20, 2010, Schedule B-5, page 3
Col.C, line 1: AEPCO Schedule E-1, page 1 of 2, 3/31/2008 amount
Col.D: Staff has accepted AEPCO's proposed Fuel Stock amount pending completion of the prudence review.

Arizona Electric Power Cooperative, Inc.
Deferred Debits

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-5
Page 1 of 1

Line No.	Month	AEPCO Proposed (A)	Staff Proposed (B)	Adjustment (C)
1	Deferred Debits	$ 12,850,764	$ -	$ (12,850,764)

Notes and Source

Cols.A: AEPCO Amended & Restated Filing, April 20, 2010, Schedule B-1, line 8, and Schedule E-1, page 1, line 18. Also see Attachment RCS-2, Schedule B, line 8.

Arizona Electric Power Cooperative, Inc.
Asset Retirement Obligation

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-6
Page 1 of 1

Line No.	Month	Adjustment (A)	Reference
	Plant		
1	ST2 ARO Ash Pond Layers	$ 546,339	See below
2	ST3 ARO Ash Pond Layers	$ 546,340	See below
3	Total ARO in Plant Acquisition Value at 3/31/2009	$ 1,092,679	
4	Adjustment to remove ARO from Plant in Rate Base	$ (1,092,679)	

Notes and Source

Lines 1-3: AEPCO's response to data request STF 2-15

Arizona Electric Power Cooperative, Inc.
Work Force Reduction

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-1
Page 1 of 1

Line No.	Description	Amount	Reference
1	Payroll	$ (641,970)	See below
2	Benefits	$ (256,790)	See below
3	Net Decrease in Labor Expense	$ (898,760)	

Notes and Source

See SWTC's supplemental response to data request STF 2.31 in Docket No. E-04100A-09-0496

Arizona Electric Power Cooperative, Inc.
Incentive Compensation Expense

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-2
Page 1 of 1

Line No.	Description	Amount	Reference
1	Incentive Compensation Expense	$ (681,900)	See below

Notes and Source
AEPCO's response to data requests STF 1.45

Arizona Electric Power Cooperative, Inc.
Donations

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-3
Page 1 of 1

Line No.	Description	Account	Amount	Reference
	Remove Donations from Test Year			
1	Donations AEPCO recorded in other than below-the-line accounts		$ 79,926	Note A
2	Adjustment to Remove Donations		$ (79,926)	

Notes and Source

[A] AEPCO's response to data request STF 1.24

Arizona Electric Power Cooperative, Inc.
Lobbying Expense in Association Dues

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-4
Page 1 of 1

Line No.	Description	Account	Membership Dues Paid To Lobbying Organizations	Date Paid	Months of Expense in Test Year	Amount In Test Year	Percent Lobbying	Adjustment
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Grand Canyon State Electric Cooperative Association ("GCSECA")	5910200	$ 161,289	Dec-07	9	$ 120,967		
2		5400930	$ 134,471	Dec-08	3	$ 33,618		
3	Subtotal GCSECA				12	$ 154,585	26%	$ (40,192)
4	National Rural Electric Cooperative ("NRECA")	5910200	$ 55,524	Feb-08	10	$ 46,270		
5		5400930	$ 73,590	Jan-09	2	$ 12,265		
6	Subtotal NRECA				12	$ 58,535	24%	$ (14,048)
7	Consumers United for Rail Equity	5400930	$ 50,000	Jan-09		$ 50,000	80%	$ (40,000)
8	Western Coal Traffic League	5400930	$ 40,000			$ 40,000	20%	$ (8,000)
9	Remove additional $10,000 of WCTL that AEPCO inadvertantly included in test year							$ (10,000)
10	Total							$ (112,240)

Notes and Source
AEPCO Response to STF 1.25
Line 9: AEPCO's response states for WCTL that:
"Actual dues are paid in the amount of $10,000 quarterly. However, for the test year, $50,000 was paid, such that an additional $10,000 was inadvertently included in the test year calculation."

Arizona Electric Power Cooperative, Inc.
Asset Retirement Obligation - Depreciation and Accretion Expense

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-5
Page 1 of 1

Line No.	Description	Account	Amount	Reference
	I. ARO Depreciation and Accretion Expense Per AEPCO			
1	Depreciation Expense	5711000	$ 30,536	A
2	Accretion Expense	5840000	$ 95,184	B
3	Total		$ 125,720	
	II. Staff Recommended Amounts for ARO Inclusion in Operating Expenses			
4	Depreciation Expense	5711000	$ -	Testimony
5	Accretion Expense	5840000	$ -	Testimony
6	Total		$ -	
	III. Staff Adjustment for ARO-Related Expenses			
7	Depreciation Expense	5711000	$ (30,536)	
8	Accretion Expense	5840000	$ (95,184)	
9	Total		$ (125,720)	

Notes and Source

A AEPCO response to STF 2-16

	Unit	Monthly Expense	No. of Months	Total
10	ST2	$ 1,212.70	8	$ 9,702
11		$ 1,391.56	4	$ 5,566
12			12	$ 15,268
13	ST3	$ 1,212.70	8	$ 9,702
14		$ 1,391.56	4	$ 5,566
15			12	$ 15,268
16	Total Both Units			$ 30,536

B AEP response to STF 1.66(f), Exhibit A, 2008 ARO Accretion

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-09-0472
Attachment RCS-3
Copies of AEPCO's Responses to Data Requests
and Documents Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

****Confidential Information has been Redacted****

Data Request/ Document	Subject	Confidential	No. of Pages	Page No.
STF 1.71	Property Held for Future Use - No Current Plans for Construction	No	1	2
STF 2-11	Property Held for Future Use - Fully Amortized Acquisition Adjustment	No	1	3
STF 1.66	Increase in Fuel Inventory; Accounting for an ARO	No	7	4 - 10
STF 2-15	AROs Recorded on Company's Books as of March 31, 2009	No	2	11 - 12
STF 1.52	Rate Case expense	No	1	13
	SWTC's Supplemental Response to Data Request STF 2.31 Regarding Workforce Reduction in Current Docket No. E-01400A-09-0496 (Includes only Confidential Attachment)	Yes	2	14 - 15
STF 3.1	Material Changes Occurred for Company between Period of March 31, 2009 and December 31, 2009	No	1	16
STF 1.31	Incentive Compensation Program - Goals	No	2	17 - 18
STF 1.45	Incentive Compensation (Includes 2008 and 2009 Incentive Compensation Plans)	No	10	19 - 28
STF 1.24	Charitable Contributions made in Test Year	No	2	29 - 30
STF 1.25	Lobbying expenses included in Association dues	No	3	31 - 33
STF 2-16	Depreciation of ARO	No	2	34 - 35
STF 1.64	Coal Transportation Legal Expenses	No	2	36 - 37
STF 1.38	Itemization of Coal Transportation Legal Expenses	No	2	38 - 39
STF 2-21	Total Railroad Litigation Costs	No	1	40
STF 2-18	Accumulation of Total Railroad Litigation Costs	No	1	41
STF 2-19	Railroad Litigation Summaries	No	1	42
STF 2-20	Railroad Litigation Settlement Discussions	No	1	43
	Total Pages Including this Page		43	

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
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March 5, 2010**

STF 1.71 Refer to Schedule B-1. Please provide a detailed itemization of each of the following items that are included in the Company's proposed rate base:

a. Line 7, plant held for future use. Identify, quantify and describe each component of the PHFFU including when it was originally purchased, the purchase cost and the planned in-service date.
b. Line 8, deferred debits. Identify, quantify and describe each component of the deferred debits. For each component, please also indicate whether it had ever been proposed for inclusion in rate base, and provide the case number where it was addressed.

Respondent: Melanie Pearce, Director of Financial Operations

Response: a. Plant Held for Future Use. A parcel of land was purchased in 2004 for the future site of an office complex. The carrying value of this parcel is \$2,538,392.31. At this time there are no plans to begin construction of the office complex.

Supplemental Respondent: Gary E. Pierson, Manager of Financial Services

Supplemental Response to 1.71(b):

b. The Deferred Debits are comprised of the items listed on STF 1.71b, attached. These deferred debits primarily consist of overhaul maintenance costs incurred by AEPCO, which are then deferred over the period of the overhaul cycle. In the preparation of the rate base schedules, AEPCO included deferred debits due to the working capital requirements of funding these expenditures. In the previous rate case, Staff made an adjustment to remove deferred debits in the amount of \$1,955,000 from rate base which was accepted by AEPCO. However, at the time of the last rate case, AEPCO was accruing anticipated overhaul costs and therefore did not include them as deferred debits. Accordingly, the deferred debit items at issue in the last rate case did not include overhaul maintenance costs

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
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STF 2-11 In the last AEPCO rate case, E-01773A-04-0528, Staff had identified $13,238 for an Acquisition Adjustment that was in Intangible Plant.

a. Has the Company removed that item from its books? If not, explain fully why not.

Respondent: Gary E. Pierson, Manager of Financial Services

Response: No. In the preparation of Schedule E-5, the balance of the Acquisition Adjustment was inadvertently included with Plant Held for Future Use. However, the Acquisition Adjustment has been fully amortized so the effect of its inclusion in the calculation of rate base is zero. The following is a summary of the balances as of March 31, 2009:

114 Acquisition Adjustment	$13,238
115 Amortization of Acquisition Adjustment	13,238
Net Acquisition Adjustment	$0
105 Plant Held for Future Use	$2,538,392

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STF 1.66 Refer to Exhibit GEP-1, Financial Statements for periods ending December 31, 2008 and 2007.

a. Explain why the coal and gas inventory increased from $8.5 million to $19.1 million from 12/31/2007 to 12/31/2008.
b. Please provide an itemization of the components of CWIP at 12/31/08 and 12/31/07.
c. Why has CWIP increased from $3.1 million to $10.1 million?
d. Why has Patronage Capital increased from $25.5 million at 12/31/2007 to $57.2 million at 12/31/2008?
e. How has the Company reflected the liability for Asset Retirement Obligations in rate base?
f. Please explain the Company's accounting for Asset Retirement Obligations and provide the journal entries used to record the amounts on page 3.
g. Referring to page 4, why has Transmission decreased from 2007 to 2008?
h. Referring to page 5, please provide the journal entries in 2007 for the Accrued Overhaul that was related to the $4,353,314.
i. In what accounts (expense and liability) was the Accrued Overhaul recorded?
j. Were there any accounting entries made for Accrued Overhaul subsequent to 12/31/2007? If not, explain fully why not. If so, please provide them.

Respondent: Melanie Pearce, Director of Financial Operations

Response:

a. As explained in the direct testimony of Dirk Minson and Gary Pierson, AEPCO's long-term coal arrangements expired at the end of 2008. While making replacement coal arrangements, AEPCO realized that the post-2008 cost of delivered coal would increase significantly both in terms of supplier rates and railroad transportation charges. Accordingly, in 2008 AEPCO developed a strategy to stockpile additional coal under the then-existing contracts to be saved and used in 2009 and 2010. Without this stockpile, the impact of the increased delivered coal costs described by Mr. Minson and Mr. Pierson would require a greater pro forma adjustment and result in a larger proposed rate increase.

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b. *See* the attached spreadsheets for the 2007 and 2008 CWIP detail.

c. The CWIP increase from \$3.1 million in 2007 to \$20.1 million in 2008 is due primarily to the following project costs:

ST2 Cooling Tower Upgrade (\$4,778,000);
ST3 Cooling Tower Upgrade (\$5,030,000);
Land Acquisition Water Resource (\$4,176,000); and
SAP Software (\$3,274,000).

d. Patronage Capital increased from \$25.5 million at 12/31/2007 to \$57.2 million at 12/31/08 because in 2008 the cooperative allocated the Unallocated Accumulated Net Margins in the amount of \$31.7 million as of 12/31/2007 to the Class A members. Included in the \$31.7 million was a recognition of an increase in equity of \$11.2 million resulting from a change in accounting methodology for overhaul costs from an accrual basis to a deferred basis. (*See* AEPCO's Audited Financial Statements for December 31, 2007).

e. AEPCO has not included the liability for Asset Retirement Obligations in its rate base because AEPCO is a non-profit cooperative whose revenue requirement is driven primarily by expense coverage and adequate TIER and DSC coverages.

f. SFAS No. 143 requires the recognition of an Asset Retirement Obligation ("ARO"), measured at estimated Fair value, for legal obligations related to decommissioning and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. The initial capitalized asset retirement costs are depreciated over the life of the related asset, with the accretion of the ARO liability classified as an operating expense. *See* the attached documents.

g. Transmission Expenses decreased from \$25.9 million in 2007 to \$18.5 million in 2008 due to Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") electing effective January 2008 to become a partial requirements member of AEPCO. The Commission approved the SSVEC conversion to partial requirements in Decision No. 70105, dated December 21, 2007. As a partial requirement member, SSVEC contracts

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directly with Southwest Transmission Cooperative, Inc, for its transmission services. This is why AEPCO's transmission expense decreased from 2007 to 2008.

h. *See* the attached documents related to the Accrued Overhaul.

i. The Accrued Overhaul was recorded in the following accounts:

5713000 – Overhaul Accrual Major (expense)
5714000 – Overhaul Accrual Minor (expense)
2616000 – Overhaul Accrual (liability)

j. There were no accounting entries made for Accrued Overhaul subsequent to 12/31/07. Beginning January 1, 2007, AEPCO adopted the deferral method of accounting for major and minor overhauls. Accordingly, incurred overhaul costs are deferred and amortized over the overhaul benefit periods based on the operating characteristics and profiles of each generating unit.

Doc.type : SA (G/L account document) Normal document

Doc. Number	100193573	Company code	AEPC	Fiscal year	2008
Doc. date	12/31/2008	Posting date	12/31/2008	Period	12
Ref.doc.	2008 LAYER ARO				
Doc.currency	USD				
Doc.head text	2008 Layer ARO				

Itm	PK	Account	Account short text	Assignment	Tx	Amount	Cost Ctr	Order	Text
1	70	1001250	317200000013 0000			60,091.00			
2	50	2302510	Asset Retirement Obl	20081231		60,091.00-			

Doc.type : SA (G/L account document) Normal document

Doc. Number	100193574	Company code	AEPC	Fiscal year	2008
Doc. date	12/31/2008	Posting date	12/31/2008	Period	12
Ref.doc.	2008 LAYER ARO				
Doc.currency	USD				
Doc.head.text	2008 Layer ARO				

Itm	PK	Account	Account short text	Assignment	Tx	Amount	Cost Ctr	Order	Text
1	70	1001250	317300000013 0000			60,091.00			
2	50	2302510	Asset Retirement Obl	20081231		60,091.00-			

Doc.type ... (G/L account document) Normal document

Doc. Number	100193575	Company code	AEPC	Fiscal year	2008
Doc. date	12/31/2008	Posting date	12/31/2008	Period	12
Ref.doc.	2008 ACCRETION				
Doc.currency	USD				
Doc.head.text	2008 Accretion				

Itm	PK	Account	Account short text	Assignment	Tx	Amount	Cost Ctr	Order	Text
1	40	5840000	Accretion Expense	20081231		7,932.00	600000		1997 Layer - ARO Accretion
2	40	5840000	Accretion Expense	20081231		7,932.00	600000		1998 Layer - ARO Accretion
3	40	5840000	Accretion Expense	20081231		7,932.00	600000		1999 Layer - ARO Accretion
4	40	5840000	Accretion Expense	20081231		7,932.00	600000		2000 Layer - ARO Accretion
5	40	5840000	Accretion Expense	20081231		7,932.00	600000		2001 Layer - ARO Accretion
6	40	5840000	Accretion Expense	20081231		7,932.00	600000		2002 Layer - ARO Accretion
7	40	5840000	Accretion Expense	20081231		7,932.00	600000		2003 Layer - ARO Accretion
8	40	5840000	Accretion Expense	20081231		7,932.00	600000		2004 Layer - ARO Accretion
9	40	5840000	Accretion Expense	20081231		7,932.00	600000		2005 Layer - ARO Accretion
10	40	5840000	Accretion Expense	20081231		7,932.00	600000		2006 Layer - ARO Accretion
11	40	5840000	Accretion Expense	20081231		7,932.00	600000		2007 Layer - ARO Accretion
12	40	5840000	Accretion Expense	20081231		7,932.00	600000		2008 Layer - ARO Accretion
13	50	2302510	Asset Retirement Obl	20081231		95,184.00-			1997-2008 Layer - ARO Accretion

Exhibit A
Arizona Electric Power Cooperative, Inc.
2008 ARO Calculation

Annual Liability Expense

2008 Layer	@ 6.600%		Annual	Bal. of the	Depreciation of	Total Annual
	For PFIV calc.	Present Value	Accretion	Liability	PV of ARO	Expense
2008	28	$120,181	$7,932	$128,113	$4,292	$12,224
2009	27	$128,113	$8,455	$136,569	$4,292	$12,748
2010	26	$136,569	$9,014	$145,582	$4,292	$13,306
2011	25	$145,582	$9,608	$155,191	$4,292	$13,901
2012	24	$155,191	$10,243	$165,433	$4,292	$14,535
2013	23	$165,433	$10,919	$176,352	$4,292	$15,211
2014	22	$176,352	$11,639	$187,991	$4,292	$15,931
2015	21	$187,991	$12,407	$200,398	$4,292	$16,700
2016	20	$200,398	$13,226	$213,625	$4,292	$17,518
2017	19	$213,625	$14,099	$227,724	$4,292	$18,391
2018	18	$227,724	$15,030	$242,754	$4,292	$19,322
2019	17	$242,754	$16,022	$258,776	$4,292	$20,314
2020	16	$258,776	$17,079	$275,855	$4,292	$21,371
2021	15	$275,855	$18,206	$294,061	$4,292	$22,499
2022	14	$294,061	$19,408	$313,469	$4,292	$23,700
2023	13	$313,469	$20,689	$334,158	$4,292	$24,981
2024	12	$334,158	$22,054	$356,213	$4,292	$26,347
2025	11	$356,213	$23,510	$379,723	$4,292	$27,802
2026	10	$379,723	$25,062	$404,784	$4,292	$29,354
2027	9	$404,784	$26,716	$431,500	$4,292	$31,008
2028	8	$431,500	$28,479	$459,979	$4,292	$32,771
2029	7	$459,979	$30,359	$490,338	$4,292	$34,651
2030	6	$490,338	$32,362	$522,700	$4,292	$36,654
2031	5	$522,700	$34,498	$557,198	$4,292	$38,790
2032	4	$557,198	$36,775	$593,973	$4,292	$41,067
2033	3	$593,973	$39,202	$633,176	$4,292	$43,494
2034	2	$633,176	$41,790	$674,965	$4,292	$46,082
2035	1	$674,965	$44,548	$719,513	$4,292	$48,840
Total			$599,332		**$120,181**	$719,513

Accretion Expense

		2008 Depreciation	2008 Accretion
Old Ponds	2006	$0	$0
New Ponds	1997	$1,395	$7,932
New Ponds	1998	$1,526	$7,932
New Ponds	1999	$1,669	$7,932
New Ponds	2000	$1,827	$7,932
New Ponds	2001	$2,002	$7,932
New Ponds	2002	$2,195	$7,932
New Ponds	2003	$2,409	$7,932
New Ponds	2004	$2,646	$7,932
New Ponds	2005	$2,908	$7,932
New Ponds	2006	$3,200	$7,932
New Ponds	2007	$3,525	$7,932
New Ponds	2008	$4,292	$7,932
Total		$29,595	**$95,184**

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO SECOND SET OF DATA REQUESTS OF
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STF 2-15 Please identify, by account, any and all Asset Retirement Obligations (AROs) recorded on AEPCO's books as of 3/31/2009 and 3/31/2008.

Respondent: Melanie Pearce, Director of Financial Operations

Response: *See* Attached Spreadsheet.

STF 2-15

Report Date: 12/31/2009
Created On: 2/25/2010

Asset Balances - 01 Book deprec.

CompanyCode: AEPC
Balance Sheet Account: 1001250

CoCd	Class	APC	Asset	SNo.	Cap.date	Asset description	Acquisition Value 3/31/2008	Acquisition Value 3/31/2009
AEPC	3172	1001250	317200000000	0	1/1/1996	ST2 ARO New Ash Pond 2003 Layer	43,653.50	43,653.50
AEPC	3172	1001250	317200000001	0	1/1/1996	ST2 ARO New Ash Pond 2004 Layer	45,159.50	45,159.50
AEPC	3172	1001250	317200000002	0	1/1/1996	ST2 ARO New Ash Pond 2005 Layer	49,606.00	49,606.00
AEPC	3172	1001250	317200000004	0	1/1/1996	ST2 ARO New Ash Pond 1996 Layer	27,907.50	27,907.50
AEPC	3172	1001250	317200000005	0	1/1/1996	ST2 ARO New Ash Pond 1997 Layer	29,749.50	29,749.50
AEPC	3172	1001250	317200000006	0	1/1/1996	ST2 ARO New Ash Pond 1998 Layer	31,713.00	31,713.00
AEPC	3172	1001250	317200000007	0	1/1/1996	ST2 ARO New Ash Pond 1999 Layer	33,806.00	33,806.00
AEPC	3172	1001250	317200000008	0	1/1/1996	ST2 ARO New Ash Pond 2000 Layer	36,037.00	36,037.00
AEPC	3172	1001250	317200000009	0	1/1/1996	ST2 ARO New Ash Pond 2001 Layer	38,415.50	38,415.50
AEPC	3172	1001250	317200000010	0	1/1/1996	ST2 ARO New Ash Pond 2002 Layer	40,951.00	40,951.00
AEPC	3172	1001250	317200000011	0	1/1/1996	ST2 ARO New Ash Pond 2006 Layer	52,880.00	52,880.00
AEPC	3172	1001250	317200000012	0	1/1/1996	ST2 ARO New Ash Pond 2007 Layer	56,370.00	56,370.00
AEPC	3172	1001250	317200000013	0	12/31/2008	ST2 ARO New Ash Pond 2008 Layer	0.00	60,091.00
							486,248.50	546,339.50
AEPC	3173	1001250	317200000000	0	1/1/1996	ST3 ARO New Ash Pond 2003 Layer	43,653.50	43,653.50
AEPC	3173	1001250	317200000001	0	1/1/1996	ST3 ARO New Ash Pond 2004 Layer	45,159.50	45,159.50
AEPC	3173	1001250	317200000002	0	1/1/1996	ST3 ARO New Ash Pond 2005 Layer	49,606.00	49,606.00
AEPC	3173	1001250	317200000004	0	1/1/1996	ST3 ARO New Ash Pond 1996 Layer	27,907.50	27,907.50
AEPC	3173	1001250	317200000005	0	1/1/1996	ST3 ARO New Ash Pond 1997 Layer	29,749.50	29,749.50
AEPC	3173	1001250	317200000006	0	1/1/1996	ST3 ARO New Ash Pond 1998 Layer	31,713.00	31,713.00
AEPC	3173	1001250	317200000007	0	1/1/1996	ST3 ARO New Ash Pond 1999 Layer	33,806.00	33,806.00
AEPC	3173	1001250	317200000008	0	1/1/1996	ST3 ARO New Ash Pond 2000 Layer	36,037.00	36,037.00
AEPC	3173	1001250	317200000009	0	1/1/1996	ST3 ARO New Ash Pond 2001 Layer	38,415.50	38,415.50
AEPC	3173	1001250	317200000010	0	1/1/1996	ST3 ARO New Ash Pond 2002 Layer	40,951.00	40,951.00
AEPC	3173	1001250	317200000011	0	1/1/1996	ST3 ARO New Ash Pond 2006 Layer	52,880.00	52,880.00
AEPC	3173	1001250	317200000012	0	1/1/1996	ST3 ARO New Ash Pond 2007 Layer	56,370.00	56,370.00
AEPC	3173	1001250	317200000013	0	12/31/2008	ST3 ARO New Ash Pond 2008 Layer	0.00	60,091.00
							486,248.50	546,339.50
							972,497.00	1,092,679.00

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
February 19, 2010**

STF 1.52 Rate Case Expense. Provide a detailed itemization of all rate case expense, including labor, benefit and overhead cost for affiliated company employees.

Respondent: Gary Pierson, Manager of Financial Services

Response: AEPCO included a rate case expense adjustment for legal and consultant costs of $160,000. That adjustment was calculated using a total estimated rate case expense of $480,000, which was then amortized over a three-year period. The total rate case expense was based on the legal fees and costs incurred in AEPCO's 2004 rate case and an estimate of rate consultant fees and costs for the current case. AEPCO did not include labor, benefit or overhead cost for affiliated company employees in its rate case expense estimate.

**SOUTHWEST TRANSMISSION COOPERATIVE, INC.
RESPONSES TO SECOND SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-04100A-09-0496
May 17, 2010**

STF 2.31 Employee Count. List the budgeted and, separately, the actual number of employees, by month, for 2008, 2009 and 2010 to date. If the labor force levels are other than full-time equivalent positions, please provide a separate listing stated in terms of full-time equivalent positions.

Respondent: Emery Silvester, Manager of Administrative Services

Response: See attached Employee Count.

Supplemental Respondent: Gary E. Pierson, Manager of Financial Services

Supplemental Response: Last month, SWTC, AEPCO and Sierra made a reduction in force of seventeen employees. SWTC calculates that the reduction in force will reduce its labor costs by about $730,000 on an annual basis. *See* the attached confidential schedule detailing the calculation of the reduced labor costs, provided pursuant to the Protective Agreement between SWTC and Staff, dated April 12, 2010. Because the reduction in force occurred more than a year after closure of the test period, SWTC has not submitted this matter as an additional pro forma adjustment in supplemental response to STF 2.35. In that regard, SWTC has also not requested adjustments for various increases in certain post-test year expenses similar to the expense increases identified by AEPCO in its response to STF 3.1, a copy of which is attached hereto. SWTC has also had such plant-in-service, net debt and other expense increases post-test year.

THIS PAGE IS CONFIDENTIAL AND HAS BEEN REDACTED

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO THIRD SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
April 14, 2010

STF 3-1 Please identify and explain changes that have occurred for AEPCO from March 31 through December 31, 2009. (a) For each such change, please identify, quantify and explain whether and how it was recognized in AEPCO's A.A.C. R14-2-103.B Schedules. If not recognized in such schedules, please explain why not.

Respondent: Gary Pierson, Manager of Financial Services

Response: We have identified the following material changes which occurred during the period March 31, 2009 through December 31, 2009:

1) Fuel Expense continued to increase due to the new coal contracts.
2) Payroll and pension expense increased due to wage increases and new NRECA pension funding requirements.
3) Capital Leases
   a) SAP software capital lease - $3.25 million
   b) Telephone System Capital Lease - $900,000
4) Plant in Service increased by approximately $23 million. Major items added during the period included:
   a) Plant Boiler Equipment ST2 - $1.5 million
   b) Plant Boiler Equipment ST3 - $7.6 million
   c) Plant Turbogenerator ST2 & ST3 (Primarily Cooling Tower Replacements) - $10.7 million
   d) GT4 Engine Upgrade - $2.5 million
5) AEPCO had additional net loan draws of approximately $15 million during the nine-month period.

Items 1, 2, and 3(a) were recognized as proforma adjustments in AEPCO's rate filing in the "C" schedules and are identified as Coal Price Adjustment, Payroll & Pension Adjustments and SAP Software Amortization Adjustment.

The Capital Lease, Plant in Service and net debt increases were not included as adjustments, because AEPCO believed Staff would not consider such post-test year expenses to be appropriate adjustments.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
February 17, 2010

STF 1.31 Employee Benefits.

a. List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to AEPCO.
b. Specifically identify the cost of any SERP or similar programs directly charged or allocated.
c. State the cost by program, of each retirement program directly charged or allocated.
d. Provide the incentive compensation program financial performance goals for the test year and for calendar years 2008 and 2009.
e. For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.
f. Provide the incentive compensation program in effect for the test year and, if different, for calendar years 2008 and 2009.
g. Show in detail how any special recognition awards recorded in the test year were determined.

Respondent: Emery Silvester, Manager of Administrative Services

Response: *See* attachment STF 1.31a – 401K Plan SPD.
See attachment STF 1.31a – Retirement Plan SPD.
STF 1.31b – N/A. AEPCO has no SERP or similar program.
STF 1.31c – *See* costs listed in the response to STF 1.28 Employee Benefits Expense for the Retirement and 401K program.
STF 1.31d – *See* the Incentive Program (Page 2) provided in response to STF 1.45 for 2008 and 2009 goals.
STF 1.31e – *See* the attached 2008 Incentive Program Goals and Results (the 2009 Goals are the same but the results are still in audit).
STF 1.31f – *See* the Incentive Program provided in response to STF 1.45 for 2008 and 2009.
STF 1.31g – N/A. There were no special recognition awards.

2008 Incentive Program Goals and Results

TeamWorks Incentive Plan 2008: December 31, 2008

AEPCO Triggers

	With Accrual *	Trigger met? Y or N
1. Positive Operating Margin		
Actual Operating Margin, Year-to-date	$16,097,468	Y
2. Times Interest Earned Ratio (TIER) of at least 1.10		
Actual TIER, Year-to-date	2.659	Y
3. Debt Service Coverage Ratio (DSCR) of at least 1.00		
Actual DSCR, Year-to-date	1.332	Y
4. Equivalent Availability Factor (EUOF) of 2.2% or less		
Actual EUOF year-to-date	1.46%	Y

AEPCO Performance Goals & Achievement

	YTD Budget/Goal	YTD Actual Achievement	Achieved Savings	Available Funding **
Non-Fuel Production Operations	$11,188,000	$10,581,718	$606,282	$303,141
Maintenance less Overhauls	$10,522,000	$9,523,265	$998,735	$499,368
Administrative & General Expenses	$9,951,000	$10,161,494	$0	$0
	$31,661,000	$30,266,477	$1,605,017	$802,509
			Maximum Payout	**$681,900**

SWTC Triggers

	With Accrual *	Trigger met? Y or N
1. Positive Net Margins		
Actual Net Margins, Year-to-date	$4,936,128	Y
2. Times Interest Earned Ratio (TIER) of at least 1.10		
Actual TIER, Year-to-date	2.000	Y
3. Debt Service Coverage Ratio (DSCR) of at least 1.00		
Actual DSCR Year-to-date	1.072	Y
4. Circuit Segment Hours Availability Factor (CSHAF) of 99.955% or better		
Actual CSHAF year-to-date	99.976%	Y

SWTC Performance Goals & Achievement

	YTD Budget/Goal	YTD Actual Achievement	Achieved Savings	Available Funding **
Transmission O&M/Systems	$10,539,000	$12,195,808	$0	$0
Administrative & General Expenses	$4,225,000	$4,065,415	$159,585	$79,793
	$14,764,000	$16,261,223	$159,585	$79,793

Total Available for Funding

AEPCO, YTD**	681,900
SWTC, YTD***	79,793
TOTAL	761,693

*Triggers must remain active with accrual of funding.
**AEPCO Savings are shared 50% to margins 50% to TeamWorks up to a maximum of $681,900
***SWTC Savings are shared 50% to margins 50% to TeamWorks up to a maximum of $318,100

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
February 17, 2010**

STF 1.45 Payroll, Incentive Programs. Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years. Identify all incentive and bonus program expense incurred in the test year and for calendar 2008 and 2009. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in the test year and in calendar 2008 and 2009.

Respondent: Emery Silvester, Manager of Administrative Services

Response: *See* attached STF 1.45 2007 Incentive Program.
See attached STF 1.45 2008 Incentive Program.
See attached STF 1.45 2009 Incentive Program.
See attached STF 1.45 Incentive Plan Expenses.

STF 1.45 2008 Incentive Program

SCHEDULE 1

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

2008 Incentive Program

Effective Date January 1, 2008

INTRODUCTION

All employees that support AEPCO can positively affect the following goals in some way. Looking at the results of the Incentive Plan is a simple way to determine how successfully AEPCO is performing. This Incentive Plan is funded through savings, by reducing actual expenditures in Non-Fuel Production Operation, Production Maintenance, and Administrative and General expenditures for AEPCO, from those forecast in the 2008 Budget. All triggers must be satisfied and the achievement with respect to the combined goals must be positive, including provision for funding the program, before the Incentive Plan will be funded. Both AEPCO and SWTC will fund the Incentive Plan proportionately. The CEO is not included in this incentive plan.

Objectives

1. To encourage and reward employees for progress towards key performance goals identified by the Management team.
2. To reinforce focus on customer service.
3. To foster strong teamwork throughout the Cooperatives.
4. To align the interests of all stakeholders: Cooperatives, customers and employees.

Trigger Mechanisms

Four trigger mechanisms must be met, or exceeded, by AEPCO to open the program to funding:

1. Positive Operating Margin.
2. Times Interest Earned Ratio (TIER) 1.10.
3. Debt Service Coverage Ratio (DSC) 1.00.
4. An Equivalent Unplanned Outage Factor (EUOF), as defined by IEEE Standard 762, equal to or less than the average EUOF of Steam Units 2 & 3 for the previous full five year period for which data is available. The target EUOF for the 2008 Incentive Plan is 2.2%, based on the average of years 2002 through 2006.

Performance Goals

Three performance goals will be combined to serve as the funding mechanism for the 2008 Incentive Plan, as follows:

1. Non-Fuel Production Operations Budget, measured in dollars;
2. Production Maintenance Budget, measured in dollars; and
3. Administrative and General (A&G) Budget, measured in total dollars spent.

Tracking Results

A monthly report will be made, displaying the year-to-date results.

Funding Amount

The Incentive Plan funding cap that has been approved by the AEPCO Board of Directors is $ 681,900, to be funded on a 50/50 split from the savings in actual expenses reduced from those forecast in the Budget.

Allocation Mechanism

The Incentive Plan covers all AEPCO, SWTC and Sierra employees except for the CEO and the Sales and Natural Gas Operations staff. It is funded by AEPCO and SWTC based on the respective amounts of the 2008 Combined Budget Total which are accountable to each. The proportionate amount of the Combined Budget Total for which each Cooperative is responsible is the funding ratio for that Cooperative. The funding ratio is then used to determine the respective incentive fund distribution cap levels for each Cooperative.

The ratio of funding for 2008, and cap levels are as follows:

AEPCO:	68.19%	or	$ 681,900
SWTC:	31.81%	or	$ 318,100
			$1,000,000

Distribution Mechanism

Following activation of their respective triggers, the total available funds for distribution will be calculated for each Cooperative. The calculation will be based upon the number of employees in each cooperative at the time of distribution.

For 2008, the total available funds for distribution will be apportioned according to the following Employee Categories: AEPCO-Designated; SWTC-Designated; and Sierra Shared.

AEPCO-Designated shall consist of the following:
AEPCO Group Employees + Sierra A Group Employees

SWTC-Designated shall consist of the following:
SWTC Group Employees + Sierra Group B Employees

Sierra Shared shall consist of the following:
Sierra C Group and E Group (less CEO) Employees

Personnel in the AEPCO-Designated Category shall have funds allocated to them by AEPCO. Personnel in the SWTC-Designated Category shall have funds allocated to them by SWTC. Personnel in the Sierra Shared Category shall have funds allocated to them by both AEPCO and SWTC.

The funding distribution mechanism operates in several steps, as follows:

1. An employee apportionment ratio is calculated according to the proportion of employees in a category to the overall employee population. The entire incentive fund amount is then preliminarily divided up amongst the employee categories in accordance with the applicable employee apportionment ratios.

2. The actual savings amount for both Cooperatives is divided into an AEPCO Portion and an SWTC Portion. Reduction ratios for the AEPCO-Designated Category and the SWTC-Designated Category are then calculated as the proportion of the Cooperative's Portion to its respective cap level.

3. The AEPCO-Designated and SWTC-Designated Categories' preliminary division of the incentive fund amount is then reduced in accordance with their respective reduction ratios.

4. After allocation to AEPCO, SWTC and Sierra of available funds to be distributed to their AEPCO-Designated and SWTC-Designated employees in accordance with this funding distribution mechanism, the remainder of the actual savings amount shall be allocated to Sierra for distribution to the Sierra Shared employees.

5. If either AEPCO or SWTC fail to trip the trigger for their respective employee categories, then the weight of funding the program for the Sierra Shared category will be borne by the Cooperative achieving its threshold triggers. Employees designated as those of the Cooperative not contributing will not be subsidized by the other Cooperative.

Incentive Plan Funding Goals for 2008

The Incentive Plan funding goal for 2008 is to reduce the actual total combined expenditures attributable to the three discrete Budget categories indicated below:

1. Non-Fuel Production Operations Budget	$ 11,188,000
2. Production Maintenance Budget	$ 10,522,000
3. Administrative and General Budget	$ 9,951,000
Budget Total	$ 31,661,000

A reduction to the combined Budget total of $ 31,661,000 by saving $ 1,363,800, or approximately 4.31% in expenditures, would reach the cap and result in funding the AEPCO Incentive Plan with $ 681,900 for the Incentive Plan and $681,900 remaining with AEPCO, for a 50/50 split of the savings. Any smaller reductions from these Budget amounts would likewise be split 50/50 between the Incentive Plan and AEPCO, providing funding for the Incentive Plan at year end at a lower amount, but still sharing the savings and the results of employee efforts.

Non-Fuel Production Operations Budget

Objective: Achieve a reduction from the 2008 Non-Fuel Production Operations Budget for all Apache Station generation units. The 2008 Non-Fuel Production Operation Budget is$ 11,188,000, as found in the published operating statement. Results will be reported monthly in the Board financial report.

Production Maintenance Budget

Objective: Achieve a reduction from the 2008 Production Maintenance Budget, which represents total maintenance budget dollars, less overhaul budget accruals and/or deferrals. The 2008 Production Maintenance Budget is $ 10,522,000 for all Apache Station generating units in 2008. Results will be reported monthly in the Board financial report.

Administrative & General Budget

Objective: Achieve a reduction of the 2008 Administrative and General Budget. The 2008 Administrative and General Budget is $ 9,951,000, as reflected in the Budget. Results will be reported monthly in the Board financial report.

STF 1.45 2009 Incentive Program

SCHEDULE 1

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

2009 Incentive Program

Effective Date January 1, 2009

INTRODUCTION

All employees that support AEPCO can positively affect the following goals in some way. Looking at the results of the Incentive Plan is a simple way to determine how successfully AEPCO is performing. This Incentive Plan is funded through savings, by reducing actual expenditures in Non-Fuel Production Operation, Production Maintenance, and Administrative and General expenditures for AEPCO, from those forecast in the 2009 Budget. All triggers must be satisfied and the achievement with respect to the combined goals must be positive, including provision for funding the program, before the Incentive Plan will be funded. Both AEPCO and SWTC will fund the Incentive Plan proportionately. The CEO is not included in this incentive plan.

Objectives

1. To encourage and reward employees for progress towards key performance goals identified by the Management team.
2. To reinforce focus on customer service.
3. To foster strong teamwork throughout the Cooperatives.
4. To align the interests of all stakeholders: Cooperatives, customers and employees.

Trigger Mechanisms

Four trigger mechanisms must be met, or exceeded, by AEPCO to open the program to funding:

1. Positive Operating Margin.
2. Times Interest Earned Ratio (TIER)1.80.
3. Debt Service Coverage Ratio (DSC) 1.50.
4. An Equivalent Unplanned Outage Factor (EUOF), as defined by IEEE Standard 762, equal to or less than the average EUOF of Steam Units 2 & 3 for the previous full five year period for which data is available. The target EUOF for the 2009 Incentive Plan is 2.2%, based on the average of years 2003 through 2007.

Performance Goals

Three performance goals will be combined to serve as the funding mechanism for the 2009 Incentive Plan, as follows:

1. Non-Fuel Production Operations Budget, measured in dollars;
2. Production Maintenance Budget, measured in dollars; and
3. Administrative and General (A&G) Budget, measured in total dollars spent.

Tracking Results

A monthly report will be made, displaying the year-to-date results.

Funding Amount

The Incentive Plan funding cap that has been approved by the AEPCO Board of Directors is $670,000, to be funded on a 50/50 split from the savings in actual expenses reduced from those forecast in the Budget.

Allocation Mechanism

The Incentive Plan covers all AEPCO, SWTC and Sierra employees except for the CEO and the Sales and Natural Gas Operations staff. It is funded by AEPCO and SWTC based on the respective amounts of the 2009 Combined Budget Total which are accountable to each. The proportionate amount of the Combined Budget Total for which each Cooperative is responsible is the funding ratio for that Cooperative. The funding ratio is then used to determine the respective incentive fund distribution cap levels for each Cooperative.

The ratio of funding for 2009, and cap levels are as follows:

AEPCO:	67%	or	$ 670,000
SWTC:	33%	or	$ 330,000
			$1,000,000

Distribution Mechanism

Following activation of their respective triggers, the total available funds for distribution will be calculated for each Cooperative. The calculation will be based upon the number of employees in each cooperative at the time of distribution.

For 2009, the total available funds for distribution will be apportioned according to the following Employee Categories: AEPCO-Designated; SWTC-Designated; and Sierra Shared.

AEPCO-Designated shall consist of the following:
AEPCO Group Employees + Sierra A Group Employees

SWTC-Designated shall consist of the following:
SWTC Group Employees + Sierra Group B Employees

Sierra Shared shall consist of the following:
Sierra C Group and E Group (less CEO) Employees

Personnel in the AEPCO-Designated Category shall have funds allocated to them by AEPCO. Personnel in the SWTC-Designated Category shall have funds allocated to them by SWTC. Personnel in the Sierra Shared Category shall have funds allocated to them by both AEPCO and SWTC.

The funding distribution mechanism operates in several steps, as follows:

1. An employee apportionment ratio is calculated according to the proportion of employees in a category to the overall employee population. The entire incentive fund amount is then preliminarily divided up amongst the employee categories in accordance with the applicable employee apportionment ratios.

2. The actual savings amount for both Cooperatives is divided into an AEPCO Portion and an SWTC Portion. Reduction ratios for the AEPCO-Designated Category and the SWTC-Designated Category are then calculated as the proportion of the Cooperative's Portion to its respective cap level.

3. The AEPCO-Designated and SWTC-Designated Categories' preliminary division of the incentive fund amount is then reduced in accordance with their respective reduction ratios.

4. After allocation to AEPCO, SWTC and Sierra of available funds to be distributed to their AEPCO-Designated and SWTC-Designated employees in accordance with this funding distribution mechanism, the remainder of the actual savings amount shall be allocated to Sierra for distribution to the Sierra Shared employees.

5. If either AEPCO or SWTC fail to trip the trigger for their respective employee categories, then the weight of funding the program for the Sierra Shared category will be borne by the Cooperative achieving its threshold triggers. Employees designated as those of the Cooperative not contributing will not be subsidized by the other Cooperative.

Incentive Plan Funding Goals for 2009

The Incentive Plan funding goal for 2009 is to reduce the actual total combined expenditures attributable to the three discrete Budget categories indicated below:

1. Non-Fuel Production Operations Budget	$ 12,280,000
2. Production Maintenance Budget	$ 10,224,000
3. Administrative and General Budget	$ 12,164,000
Budget Total	$ 34,668,000

A reduction to the combined Budget total of $ 34,668,000 by saving $1,340,000, or approximately 3.90% in expenditures, would reach the cap and result in funding the AEPCO Incentive Plan with $ 670,000 and $670,000 remaining with AEPCO, for a 50/50 split of the savings. Any smaller reductions from these Budget amounts would likewise be split 50/50 between the Incentive Plan and AEPCO, providing funding for the Incentive Plan at year end at a lower amount, but still sharing the savings and the results of employee efforts.

Non-Fuel Production Operations Budget

Objective: Achieve a reduction from the 2009 Non-Fuel Production Operations Budget for all Apache Station generation units. The 2009 Non-Fuel Production Operation Budget is$12,280,000, as found in the published operating statement. Results will be reported monthly in the Board financial report.

Production Maintenance Budget

Objective: Achieve a reduction from the 2009 Production Maintenance Budget, which represents total maintenance budget dollars, less overhaul budget accruals and/or deferrals. The 2009 Production Maintenance Budget is $ 10,224,000 for all Apache Station generating units in 2009. Results will be reported monthly in the Board financial report.

Administrative & General Budget

Objective: Achieve a reduction of the 2009 Administrative and General Budget. The 2009 Administrative and General Budget is $12,164,000, as reflected in the Budget. Results will be reported monthly in the Board financial report.

STF 1.45 Payroll Incentive Programs

Teamworks Incentive Plan

	AEPCO	
2008	$681,900	**This amount is the only expense incurred during the test period**
2009	$0.00	**No expense has yet been incurred for 2009 (audit still in progress)**

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
February 12, 2010

STF 1.24 Contributions. For the test year, please list all contributions for charitable and political purposes, if any, recorded in accounts other than below the line. Indicate the amount of the expenditure, the recipient of the contribution, and the specific account charged. Also identify for the test year the amounts of contributions for charitable and political purposes charged to the Company from affiliates in accounts other than below the line accounts.

Respondent: Melanie Pearce, Director of Financial Operations

Response: *See* the attached spreadsheet.

Arizona Electric Power Cooperative, Inc.
Donations
For the Test Year Ended March 31, 2009

		Amount
National G & T Managers Associations	$	31,981.00
Touchstone Energy Events Sponsorship - Trico Electric Coop	$	5,000.00
Touchstone Energy CFL Education Kits	$	89.92
El Tour de Tucson Official Energy Sponsor	$	1,500.00
Boy Scouts Golf Fundraising Event	$	5,000.00
2008 U of A Ag Cat Open	$	6,000.00
2008 Sierra Vista Open	$	5,000.00
Southern Arizona Junior Golf Association Invitational Tournament	$	1,000.00
Touchstone Energy Events Sponsorship - Trico Electric Coop	$	5,000.00
NET Conference G & T Alliance	$	6,000.00
Touchstone Energy Events Sponsorship - Duncan Valley Class of 2008	$	5,000.00
Boy Scouts - Plastic Gift Bags	$	75.59
Table Throws	$	2,263.18
NRECA	$	(4,234.00)
Mohave Electric Coop - Annual Community Days	$	5,000.00
Donation - Banner on Gym Wall - St David Public Schools	$	250.00
Touchstone Energy Events Sponsorship - Graham County Electric Coop	$	5,000.00
	$	79,925.69

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
March 5, 2010**

STF 1.25 Dues, Industry Associations. Please list all membership payments made to industry associations (e.g., National Rural Electric Cooperative Association, etc.) requested for recovery during the test year. Identify the account into which such amounts are charged.

a. State the purpose and objective of each organization listed.
b. Provide descriptive material the Company has concerning each organization's financial statements, annual budget and activities.
c. Do any of the organizations listed engage in lobbying or advocacy activities, attempts to influence public opinion, institutional or image-building advertising? If so, list each organization which engages in such activities, and state the Company's best estimate of the portion of the organization's expenses devoted to such activities. Explain and show how such estimates were derived. State if the Company has included the portions of dues related to such activities in the test year.

Respondent: Melanie Pearce, Director of Financial Operations

Response: *See* the attached spreadsheet. A supplemental response will be provided to (b) and (c).

Supplemental Response: *See* the attached revised association dues spreadsheet.

a. *See* the attached documentation regarding GSECA, NRECA, and Touchstone Energy.

Consumer's United for Rail Equity (CURE): CURE is a coalition of freight rail customers seeking changes in federal law and policy that would require railroads to provide more competitive pricing and reliable service. CURE's goal is to hold railroads accountable to their customers and the public. An umbrella membership organization, CURE includes large trade associations that represent more than 3,500 electric, utility, chemical, manufacturing and forest and paper companies and their customers.

Western Coal Traffic League (WCTL): WCTL is a voluntary association comprised of consumers of coal mined in the western United States. WCTL members purchase over 120 million tons of coal annually. WCTL's principal mission is to encourage Congress, executive

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
March 5, 2010

departments, administrative agencies, and the courts to establish and apply standards that promote the lowest delivered costs for its members' coal purchases.

Additional information may be obtained at gseca.org, nreca.coop, touchstoneenergy.cooperative.com, railcure.org, opensecrets.org.

b. *See* the attached annual reports for GSECA and NRECA. Similar documents are not available to AEPCO concerning Touchstone Energy, CURE, and WCTL.

c. GSECA, NRECA, CURE, and WCTL engage in lobbying and advocacy activities. GSECA estimates that 26% of its dues go to lobbying and advocacy activities. This information was provided by Nicolle Migliaccio of GSECA. NRECA estimates 24%. This information was provided by Tiffany Jaggers of NRECA. CURE estimates that 80% of its dues go to lobbying. This information was provided by a member of Van Ness Feldman, PC. WCTL estimates that last year approximately 20% of its budget went to lobbying. This estimate was provided by Pete Pfohl of WCTL

Arizona Electric Power Cooperative, Inc.
Association Dues

Memberships	Amount Paid	Date Paid	Monthly Allocation	G/L Number
GCSECA	161,288.85	Dec-07	13,440.73	5910200 *
NRECA	55,524.00	Feb-08	4,627.00	5910200 *
Touchstone	121,070.00	Jan-08	10,089.16	5910200 *
GCSECA	134,470.98	Dec-08	11,205.92	5400930 *
NRECA	73,590.24	Jan-09	6,132.52	5400930 *
Touchstone	125,500.00	Mar-09	10,458.33	5400930 *
Consumers United for Rail Equity	50,000.00	Jan-09	-	5400930
Western Coal Traffic League	50,000.00	**	-	5400930

* These are amortized over 12 months and only the portion of the dues attributable to the 12 months in the test year are included in AEPCO's calculation.

** Actual dues are paid in the amount of $10,000 quarterly. However for the test year, $50,000 was paid, such that an additional $10,000 was inadvertently included in the test year calculation.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO SECOND SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
March 24, 2010

STF 2-16 During the test year, did AEPCO record any amounts in any income statement accounts related to AROs and/or Statement of Financial Accounting Standards No. 143 (FAS 143)? If not, explain fully why not. If so, please identify, quantify and explain the amounts by account.

Respondent: Melanie Pearce, Director of Financial Operations

Response: *See* the attached spreadsheet.

STF 2-16

Arizona Electric Power Cooperative, Inc.
Asset Retirement Obligations
For the Test Year end March 31, 2009

	Accumulated Depreciation ARO - ST2	Depreciation Expense	Accumulated Depreciation ARO - ST3	Depreciation Expense
	1081210	**5711000**	**1081310**	**5711000**
Apr-08	(1,212.69)	1,212.69	(1,212.69)	1,212.69
May-08	(1,212.72)	1,212.72	(1,212.72)	1,212.72
Jun-08	(1,212.75)	1,212.75	(1,212.75)	1,212.75
Jul-08	(1,212.65)	1,212.65	(1,212.65)	1,212.65
Aug-08	(1,212.72)	1,212.72	(1,212.72)	1,212.72
Sep-08	(1,212.69)	1,212.69	(1,212.69)	1,212.69
Oct-08	(1,212.74)	1,212.74	(1,212.74)	1,212.74
Nov-08	(1,212.72)	1,212.72	(1,212.72)	1,212.72
Dec-08	(1,391.52)	1,391.52	(1,391.52)	1,391.52
Jan-09	(1,391.56)	1,391.56	(1,391.56)	1,391.56
Feb-09	(1,391.56)	1,391.56	(1,391.56)	1,391.56
Mar-09	(1,391.56)	1,391.56	(1,391.56)	1,391.56
		15,267.88		15,267.88

30,535.76

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
March 5, 2010**

STF 1.64 Refer to the testimony of Mr. Pierson at page 8.

a. Please identify all "coal legal expenses" by account for the test year used in the last rate case and each subsequent year.
b. Has the Company sought any similarly situated other utilities to assist it and share the cost of litigation for the matters being pursued against the railroad(s)? If not, explain fully why not. If so, please explain fully.
c. Please provide a copy of the claim against BN that the Company has filed at the STB concerning rail transportation rates. Include each amendment that has been made to the claim.

Respondent: Gary Grim, Sr. Vice President & Chief Operating Officer

Response:

a. We are encountering difficulties assembling the requested data due to our conversion after the last rate case from the JDE to SAP accounting system. A supplemental response will be provided.

b. AEPCO has not sought assistance from any other utilities to share in the cost of its litigation efforts for the matters being pursued against the railroad(s). AEPCO's rate case before the Surface Transportation Board is a matter that concerns only AEPCO and its specific coal and transportation issues. If AEPCO is successful in its rate case, AEPCO is the only party that will benefit.

c. *See* the attached claim and four subsequent amendments thereto.

Supplemental Respondent: Melanie Pearce, Director of Financial Operations

Supplemental Response to 1.64(a):

a.

2004	$982,000
2005	$66,600
2006	$38,100
2007	$92,100
2008	$292,000
2009	$2,800,000

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These expenses are found in account number 5300700.

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March 5, 2010**

STF 1.38 Legal Expense.

a. Please itemize the amount of non-rate case legal expense for the test year. For each distinct item over $20,000, show payee, amount, account, and indicate what services were performed and what the subject matter of the services was.
b. Please identify for the test year, and for the calendar years, 2006 through 2009, by account, all legal and consulting costs related to matters involving railroad rates and any disputes about railroad rates related to transportation of coal to the Apache Plant.

Respondent: Dwight M. Whitley, Jr., Corporate Counsel

Response: a. AEPCO's total legal expenses, excluding rate-case expenses, for the test year were $1,376,086.92. Please see Attachment 1.38(a) for a summary of AEPCO's total legal expenses, excluding rate case expenses, for the test year.

b. AEPCO's legal and consulting costs, for calendar years 2006 through 2009 and the test year, related to matters involving railroad rates and any disputes about railroad rates related to transportation of coal to the Apache Station are as follows:

2006	$35,538.68
2007	$92,101.60
2008	$278,669.24
2009	$2,804,789.68
Test year	$524,694.24

Supplemental Response:

a. AEPCO's total legal expenses, excluding rate-case expenses, for the test year were approximately $1,394,000. *See* the revised Attachment 1.38(a) for a summary of AEPCO's total legal expenses, excluding rate case expenses, for the test year.

b. AEPCO's legal and consulting costs, for calendar years 2006 through 2009 and the test year, related to matters involving railroad rates and any disputes about railroad rates related to transportation of coal to the Apache Station are as follows:

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
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2006	$38,100
2007	$92,100
2008	$292,000
2009	$2,800,000
Test year	$538,000

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO SECOND SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
March 19, 2010**

STF 2-21 What amount of total litigation cost does AEPCO project to incur with respect to the matters in dispute with the railroad and coal suppliers?

Respondent: Dwight M. Whitley Jr., Corporate Counsel

Response: The six month projection for February 2010 through July 2010 is $240,000 for legal costs and $590,000 for consulting and other expenses. No other information is provided after the six month projection.

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO SECOND SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
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March 19, 2010**

STF 2-18 Please list the total amount AEPCO has spent through 1/31/2010 on the coal and railroad litigation. Please show the accumulation of the total amount by year, broken out between (1) legal, (2) consulting and (3) other.

Respondent: Dwight M. Whitley Jr., Corporate Counsel

Response: AEPCO does not account separately for consulting and "other" expenses related to litigation. These costs are booked together with the litigation legal fees.

The accumulated totals, by year, for the matter pending before the Surface Transportation Board (as described in the response to STF 2-19) are as follows: \$79,800 (2008); \$2,759,300 (2009); and \$602,800 (through January 2010).

The accumulated totals, by year, for the district court lawsuit against Union Pacific Railroad (as described in the response to STF 2-19) are as follows: \$35,000 (2009); and \$1,800 (through January 2010).

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ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
March 19, 2010**

STF 2-19 Please provide a brief summary describing the issues in dispute and the current status of the litigation with the railroad and with any coal suppliers.

Respondent: Dwight M. Whitley, Jr., Corporate Counsel

Response: AEPCO is in the process of seeking regulatory relief from coal transportation rates imposed by the BNSF Railway (BNSF) and the Union Pacific Railroad (UP) through the Surface Transportation Board's (STB) Stand Alone Cost Railroad process. This case was filed in December 2008 with opening evidence and argument submitted by AEPCO January 25, 2010. The railroad's reply case is due in May 2010.

AEPCO is also involved in litigation with the UP. UP filed a complaint in January 2009 in U.S. District Court against AEPCO. This complaint alleges that AEPCO refuses to recognize a contract for coal transportation from Colorado and Wyoming coal sources. AEPCO contends that no contract was signed and does not exist. This case continues pending settlement discussions.

AEPCO is not involved in any dispute or litigation with the coal suppliers.

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STF 2-20 To date, has AEPCO engaged in any settlement discussions with the coal suppliers and/or railroad concerning the matters being litigated? If not, explain fully why not. If so, please briefly summarize the status of such discussions.

Respondent: Dwight M. Whitley Jr., Corporate Counsel

Response: AEPCO has been involved in settlement discussions with both the Union Pacific Railroad (UP) and the BNSF Railway (BNSF). AEPCO is currently engaged in settlement discussions with the UP. While settlement proposals were exchanged between AEPCO and the BNSF, these proposals were rejected by both parties and AEPCO and the BNSF are not currently engaged in settlement discussions.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF THE 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-09-0472

DIRECT

TESTIMONY

OF

RANDALL VICKROY

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 02, 2010

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ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-09-0472

AEPCO has requested a slight decrease in its overall revenue requirement of about $97,000 annually, or a decrease of 0.06 percent. AEPCO has based its revenue requirement request on targeting a Debt Service Coverage ("DSC") of 1.275 and a Times Interest Earned Ratio ("TIER") of 1.30, along with a composite cost of debt of 5.92 percent for the test year ended March 31, 2009. AEPCO's actual net margins during the test year were $15.8 million. However, the loss of three major wholesale sales contracts and increases in coal costs and other operating expenses have caused the Cooperative to make $12.5 million in pro forma reductions in margins by December 31, 2010. AEPCO is not proposing to increase its rates to recover these lost margins; the expected net margin level with proposed rates drops to only $3.2 million.

I have determined a target range for DSC on which rates should be set at 1.25 to 1.45. My analysis applies credit rating agency financial targets and credit risk profiles for generation and transmission cooperatives, and applies them to AEPCO. I recommend that AEPCO's DSC should be 1.40, due to the Cooperative's overall credit risk profile which would also produce a TIER of 1.51 and net margins of about $5.5 million annually.

INTRODUCTION

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

A. My name is Randall Vickroy. I am a senior consultant for The Liberty Consulting Group ("Liberty") My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Have you prepared summaries of your background and qualifications?

A. Yes, they are provided in Exhibit LCG-1.

Q. Mr. Vickroy, please describe your educational background and professional experience as they relate to the subjects of this testimony.

A. I spent 12 years with a major Mountain States electric and gas utility, starting as a Financial Analyst in the corporate finance and planning department, and then became Financial Supervisor, Director of Analysis, Business Development Manager, and Assistant to the Chief Financial Officer. My responsibilities included financial planning, capital acquisition, capital spending analysis and allocation, treasury operations, securitization financing, project financing, mergers and acquisitions, cash management, and investor relations.

I have been consulting since 1991 on corporate finance and business issues in the electricity, natural gas, and telecommunications industries. During this time, I have provided consulting services to utility commissions and to companies in over 25 states and in three foreign countries. I received a Bachelor of Arts from Monmouth College with a major in business administration and a Masters of Business Administration degree from the University of Denver with an emphasis in finance.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff of the Arizona Corporation Commission ("Staff" or "ACC").

Q. What is the purpose of your testimony?

A. My testimony provides a review, evaluation, and recommendations regarding the cost-of-capital issues for the Arizona Electric Power Cooperative ("AEPCO" or "Cooperative") rate filing, as summarized in its Amended and Restated Schedules A-1 and A-2. Cost-of-capital issues include the cost of debt, risk factors as they affect the cost of capital, financial coverage ratios such as Times Interest Earned Ratio ("TIER") and Debt Service Coverage ("DSC"), equity ratios, and cash flow metrics and indicators. I also discuss my evaluation of whether AEPCO's cost-of-capital request provides adequate margins, debt coverage, and cash flow to finance its investment and operations as of the test year ended March 31, 2009.

Q. Why does AEPCO consider the rate increase request to be necessary?

A. AEPCO has experienced strong financial performance in each of the years 2007 through 2009. The higher net margins generated during recent years have increased AEPCO's equity ratio as a percentage of capitalization, from only about 5 percent at the end of 2005 to over 28 percent at March 31, 2009. However, by December 31, 2010 a series of very significant business changes will substantially affect AEPCO's financial outlook. The largest items affecting financial status are increases in coal prices and the expiration of three large sales contracts to AEPCO's Class B members. The contract loss of most significance is the expiration of the 100 MW Salt River Project ("SRP") contract on December 31, 2010. This contract produces $13.2 million of annual margins. Part of the margins from these lost contract sales will be offset by assigning portions of the contract capacity to Mohave Electric Cooperative ("Mohave") and Sulphur Springs Valley Electric Cooperative ("Sulphur Springs"). AEPCO has also experienced higher overhaul and maintenance costs on its power plants in recent years, as the plants age. AEPCO has presented a series of pro forma adjustments for these major changes, which have a net result of decreasing margins by $12.5 million annually, as shown in AEPCO's Amended and Restated Schedule C-2, page 10 of 10.

AEPCO's request does not include a rate increase to offset the lost margins. AEPCO had a net margin of $15.8 million in the test year ended March 31, 2009. Under the proposed rates, the net margin is expected to fall to $3.2 million.

AEPCO FINANCIAL RESULTS

Q. What have APECO's financial results been over the past several years?

A. The DSC, TIER, and equity as a percent of total capitalization comprise primary financial ratios and indicators of AEPCO's financial health under AEPCO's Rural Utilities Service ("RUS") mortgage and other existing loan documents. AEPCO's RUS mortgage agreement debt covenants require both a DSC and a TIER of at least 1.0 in two of three consecutive years. Exhibit LCG-2 provides AEPCO's DSC, TIER, and equity ratio for each year from 2000 through 2009.

We consider the DSC to be more significant and important here than the TIER. The DSC takes into account components of cash flow (such as depreciation and principal payments), and provides a better indicator of an enterprise's generation of sufficient cash to meet its debt and principal requirements. TIER is more focused on book earnings, rather than cash. Exhibit LCG-2 shows that AEPCO's DSC ratios were below its mortgage document requirements in each year from 2003 through 2005. Following a rate increase, AEPCO's

DSC improved to 1.16, 1.37, 1.33 and 1.70 for the years 2006-2009, respectively. TIER levels were 2.13, 2.81, 2.66 and 1.94 for the same years. AEPCO's equity ratio increased from about 5 percent at the end of 2005 to 29.45 percent at the end of 2009. AEPCO's financial results and covenant coverage ratios have been strong since the 2005 rate case and through the test year.

Q. Please summarize AEPCO's actual results for the test year, and as affected by the loss of the SRP contract business, coal price increases, and the other factors it has cited.

A. AEPCO's Amended and Restated Schedule A-2 reports actual net margins of about $15.8 million for the test year ended March 31, 2009. AEPCO's adjustments for margins lost from its power sales contracts, increased coal costs, and other adjustments to operating expenses reduce that healthy margin to $3.3 million for the same test year. AEPCO's DSC for the test year would fall from 1.39 to 1.28, and TIER would fall from 2.50 to 1.30.

Q. What would AEPCO's expected financial results for the test year be if its proposed rate adjustment is approved?

A. AEPCO based its requested rate change upon producing the revenue necessary to achieve a DSC of 1.275 in the test year. The requested slight rate decrease would also result in a TIER of about 1.30. AEPCO has calculated that these coverage ratios would provide net margins of about $3.2 million per year. AEPCO has estimated that the slight reduction in rates would decrease equity as a percentage of capitalization to 27.5 percent from about 28.1 percent at the end of the projected year ending March 31, 2010.

AEPCO COST OF DEBT

Q. Please summarize AEPCO's calculations of its cost of debt.

A. AEPCO's Amended and Restated Schedules D-1 and D-2 calculate long-term debt interest for the test year ended March 31, 2009 as $10,812,194, on debt outstanding of $178.1 million. The long-term debt interest arises primarily from interest on AEPCO's Federal Financing Bank ("FFB") debt. This debt consists of numerous notes, which account for about $111.7 million (over 62 percent) of long-term debt outstanding. AEPCO also had outstanding at March 31, 2009 long-term debt with the following lenders: Central Bank for Cooperatives ($21.1 million), the National Rural Utilities Cooperative Finance Corporation ("CFC") ($29.5 million), CFC Series 1994A bonds ($15.4 million), and Rural Electric Administration ("REA") debt of $0.5 million.

AEPCO annualized the interest charges for long-term debt in place at the end of the test year. AEPCO then added to the annualized interest expense a $0.329 million payment to SWTC for interest on regulatory assets that remained on AEPCO's books following the 2001 restructuring. The net result of annualizing the interest and adding the SWTC interest payments was a net increase of $231,437 above the test year's actual long-term debt interest costs. AEPCO's Schedule D-2 for the test year shows the results of the annualization of interest charges. Annualized long-term debt interest of $10.812 million produces a cost rate of 6.07 percent on the $178.1 million principal for the test year.

AEPCO's cost of capital filing also includes short-term debt of $15.85 million outstanding on its $25 million CFC credit facility at March 31, 2009. The interest rate is 4.25 percent. AEPCO Schedule D-1 shows a cost of debt summary for AEPCO, generating a composite rate of 5.92 percent on $193.9 million of total debt outstanding.

Q. What do you conclude about the appropriateness of AEPCO's annualization adjustment as a basis for adjusting the cost of debt?

A. I consider the interest annualization to be properly reflective of a known and measurable adjustment process. The annualization updates the cost of debt for new issuances and for maturities of existing debt that occur during the test year. It better represents debt costs expected to be incurred, when compared with test-period interest expense.

Q. Does AEPCO expect its long-term debt to change significantly following the test year?

A. Yes. To reflect expected additional draws from FFB and maturities on some of its other debt outstanding, AEPCO also projected in Schedules D-1 and D-2 that its long-term debt would increase from \$178.1 million to \$192.8 million in the 12 months following the test year. For instance, AEPCO had drawn \$26.2 million of FFB debt in 2009, and expected to draw an additional \$12 million prior to March 31, 2010. Each draw would be at interest rates lower than the 6.07 percent of the test year. The weighted average cost of the long-term debt would decrease from the annualized 6.07 percent to 5.72 percent. However, AEPCO's estimates of the out-of-test-period changes in the principal amount outstanding and the weighted average cost of long-term debt are not known and measurable adjustments that AEPCO has requested.

Q. Please describe your understanding of the extension of maturities on AEPCO's FFB debt and its effect on debt principal payments.

A. AEPCO (as well as SWTC) recognized that very high levels of principal payments on its long-term debt greatly exceeded the depreciation levels built into existing rates. This phenomenon caused cash flow shortages even as net margins remained healthy during the past few years. For instance, principal payments for AEPCO in 2007 were \$17.8 million, while depreciation and amortization amounted only to $8.0 million. The elevated principal payment levels also made meeting minimum DSC ratios more difficult, because principal payments are included in DSC obligations that must be "covered" with operating cash sources. AEPCO and SWTC discussed with RUS extending the loan maturities on certain FFB issuances to coordinate their terms better with the cooperatives' new, longer estimates of the remaining generation and transmission asset useful lives. As of December 31, 2008, the maturities of most AEPCO loans with FFB had been extended.

The maturity extensions greatly reduced principal payments, starting in 2009. Total principal payments for AEPCO were $14.1 million during the test year, but were projected to fall to $6.8 million in the following 12 months. As a result of extending the maturities, AEPCO will have higher DSC coverage and cash flow following the test year.

Q. Please explain AEPCO's request for the inclusion of short-term debt in the capital structure as of March 31, 2009.

A. AEPCO had, at the end of the test year on March 31, 2009, $15.85 million outstanding on its $25 million credit facility with CFC. AEPCO included this short-term debt amount in its cost of debt calculation, at an interest rate of 4.25 percent. AEPCO has effectively annualized the interest rate on the $15.85 million amount, and included it in the cost of debt, consistent with the long-term debt portion. AEPCO's rationale in including short-term interest in the cost of capital is the assumption that a similar level of short-term debt is required to fund the various working capital needs of AEPCO during the test year. This rationale is reasonable for the cost of debt calculation and its inclusion results in a lower composite cost of debt.

Q. What is your overall evaluation of the AEPCO's requested cost of debt as presented in Schedules D-1 and D-2?

A. AEPCO's requested composite cost of debt of 5.92 percent accurately represents the annualized cost of debt experienced by AEPCO as of the end of the test year on March 31, 2009.

AEPCO RETURN REQUIREMENTS

Q. Please explain your method for estimating AEPCO's cost of capital and coverage requirements.

A. I have evaluated AEPCO's cost of capital and coverage requirements based on risk evaluation techniques used by the credit rating agencies. The rating agency techniques include both quantitative criteria that are based on financial metrics and qualitative criteria associated with the business risks of generation and transmission ("G&T") cooperatives. The financial credit metrics provide a quantitative foundation for the financial results required to achieve a lower-to-mid-level investment grade rating. I then factored in qualitative criteria also used by the rating agencies to evaluate the business risks that are specific to AEPCO. Utilizing both the quantitative and qualitative risk factors, I then established a target range of DSC coverage ratios that may be used to set rate levels. As I have noted previously, the DSC ratio is preferred for use in evaluating G&Ts financial strength, because it takes into consideration cash requirements and principal payments, which are substantial for most cooperatives.

The actual historical levels of financial results for G&T cooperatives may then be checked against the target range to test for reasonableness. Finally, I considered AEPCO's current prospects (as indicated by its projected capital expenditure program, cash situation, and other contingencies), in order to determine the recommended DSC level, and its commensurate cash flow, within the established range.

Q. How do you define the required rate of return or cost of capital used to set rates for AEPCO?

A. The determination of a coverage ratio to calculate AEPCO's return requirements must produce financial results that will allow AEPCO to meet member power requirements, maintain financial strength, and raise capital from the RUS and CFC and from capital markets, as necessary. A fundamental principle of utility finance, whether the utility is investor-owned or a cooperative, is that the enterprise must be able to attract capital at a reasonable cost in order to build and maintain its physical plant and to meet its public service obligations. The failure to maintain the financial integrity of a cooperative is not in the interests of either its members or lenders. At a minimum, an entity like AEPCO must be afforded the opportunity not only of assuring its financial integrity to attract additional capital as needed, but also of achieving margins and financial results that are commensurate with its risk profile.

Q. Please explain your basis for determining the appropriate risk parameters for AEPCO.

A. The established sources of evaluations of risk and credit standing are the three major credit rating agencies: Moody's Investors Service ("Moody's"), Standard and Poor's ("S&P"), and Fitch. The rating agencies apply similar criteria when evaluating the risks of G&T cooperatives. Moody's has recently updated and refined its criteria for rating G&Ts, and has clearly defined its actual ratings on 17 electric G&T cooperatives as of December 2009. However, these rating agency criteria are appropriate for determining a reasonable target for financial metrics that fully considers the business and financial risks of AEPCO.

Q. What are the primary factors that rating agencies consider important in assessing the risk of G&T cooperatives?

A. The rating agencies' analysis of U.S. electric G&T co-ops focuses on five key rating factors considered central to assigning ratings in this sector. These rating factors include quantitative and qualitative measures for establishing the risk profile of a cooperative. The five key factors and Moody's weighting of each factor are as follows:

1. Financial Performance and Metrics (40 percent)
2. Long-term Wholesale Power Supply Contracts/Regulatory Status (20 percent)
3. Rate Flexibility (20 percent)
4. Member Profile (10 percent)
5. Size (10 percent).

Financial performance and strength are important indicators of a G&T cooperative's ability to meet its obligations, especially interest and debt service. The rating agencies analyze financial indicators and ratios to measure the ability to cover fixed and variable obligations. They analyze the DSC and the TIER, recognizing that these two ratios have been used to measure minimum compliance with RUS loan documentation for many years, and provide a bare, minimum level of financial results that must be met. They also analyze standard cash flow indicator ratios, specifically funds from operations coverage of interest ("FFO/Interest") and funds from operations coverage of debt ("FFO/Debt"). These ratios are most important to the rating agencies, because they provide insight into the amount and quality of a cooperative's cash flow and its ability to service its debt. Cooperative equity as a percentage of total capitalization is also evaluated by the rating agencies to determine how much flexibility exists on the balance sheet to absorb unexpected events and losses.

These five financial ratios comprise the primary quantitative determinants of the risk profile for G&T cooperatives. Together, they account for 40 percent or more of the weighting in rating agency evaluations.

The remaining four criteria categories used to develop risk profiles are more qualitative in nature, but most are measurable. Long-term wholesale power supply contracts between G&T cooperatives and their members provide G&Ts with a high degree of assurance that costs and capital investment can be recovered in rates charged to members. Most of these member wholesale contracts require the member cooperatives to purchase all or virtually all of their power supply from the G&T. The members must also pay their pro-rata portion of the G&T's fixed and variable costs. A higher percentage of capacity and energy sold to full or partial requirements members is considered less risky than outside wholesale contracts or other sales to non-members. Regulatory status is also part of this ratings factor. Regulatory control over the rate setting process (such as in Arizona) is considered by the rating agencies to leave a cooperative with less flexibility to raise rates if needed.

Rate flexibility is another credit factor that relates to cost recovery efficiency. The timing and extent to which a G&T cooperative can increase rates is influenced by how active its board of directors has historically been regarding rate actions. Fuel and purchased-power adjustment mechanisms are viewed favorably, especially when the recovery of cost increases is deferred for shorter time periods. The degree of reliance on purchased power comprises another credit factor. Heavy reliance indicates higher exposure to price volatility. New-build exposure is also measured by the rating agencies. A larger construction program is considered to be a credit negative, because the issuance of increased levels of debt to finance the program and resulting rate increases increase risk. Finally, cost competitive cooperatives are viewed more favorably, because they have greater flexibility to raise rates as costs rise or to build equity capital to levels that would cover operational problems.

Member profiles measure the degree of a G&T's residential sales, or less risky sales, by its members. The consolidated member's equity capital as a percentage of capitalization is also considered in determining the strength of members.

The size factor is measured by megawatt-hour sales and by net property, plant, and equipment. The rating agencies believe that megawatt-hour sales comprise an important indicator of economies of scale. They also believe that having a greater asset base may be beneficial if the G&T can benefit from having a larger pool of assets and a more diverse source of fuels to operate the generation assets that it owns. Less asset concentration in one generating plant is considered preferable due to the risk of extended outages and replacement power costs.

Q. Please explain how you analyzed the rating agency targets for financial metrics to apply to AEPCO.

A. I used Moody's financial metrics for electric G&T cooperatives to determine the financial criteria for both a "Baa" rating and an "A" rating. Moody's has published a range for each rating level for each of the five key financial metrics for G&Ts mentioned previously. I consider the Baa rating, the lowest investment grade category, to be the minimum acceptable rating and level of financial strength here. I have also included the "A" rating criteria so that financial metric mid-points related to the combination of the A and Baa categories may be determined. My Exhibit LCG-3 provides the ranges of financial metrics that qualify for each of the Moody's ratings levels. Exhibit LCG-3 also shows the mid-point of these two ratings ranges for each financial metric, which I consider to be a reasonable target for the quantitative financial metric portion of this analysis. Exhibit LCG-3 also provides the pro forma financial metrics that would be generated by AEPCO during the test year under its proposed rates, as shown in AEPCO's Schedule A-2.

Please note in the exhibit that values for the mid-points of the ratings categories for the financial metrics are generally close to the pro forma results of AEPCO's rate request. The rating mid-point DSC coverage, for instance, is 1.25, as compared to the company's request of 1.275. Based solely upon the quantitative metrics, AEPCO's rate request could produce financial results that would qualify the Cooperative for an investment-grade credit rating in either the Baa or A categories. However, we have yet to account for numerous qualitative factors and AEPCO business factors that can influence these quantitative results upward or downward.

Q. How do qualitative factors influence the analysis of AEPCO's risk profile?

A. The financial metrics provide a quantitative basis for determining AEPCO's risk profile. We have determined that the financial targets included in its rate request, if realized over a period of years, would probably qualify the company to be rated around A-/Baa+. As we have noted, Moody's gives a 40 percent weight to the financial metrics and 60 percent to the remaining four rating factors. I should also note here that the other ratings factors to be discussed often tend to have an overriding influence on whether an enterprise can actually realize the targeted returns included in rate filings.

AEPCO is somewhat more risky with regard to the rating factors of long-term wholesale power supply contracts and regulatory status. The Cooperative has a high percentage of member load under long-term partial requirements contracts through 2035, which is a positive rating factor. On the other hand, AEPCO is rate-regulated by the ACC, which Moody's considers a negative factor for purposes of ratings. The combination of AEPCO's member wholesale contract status and regulatory status falls into Moody's "Baa" category, a somewhat negative rating factor as compared to its targeted financial metrics.

The rate-flexibility factor indicates overall higher levels of risk for AEPCO. Two out of the four rate-flexibility categories would be placed in Moody's "Baa" category. These two are board involvement in setting rates/fuel recovery mechanisms and new-construction-build exposure. In the rate competitiveness category, AEPCO would be significantly riskier, falling between the "Baa" and "Ba" (below investment grade) categories. The Cooperative's low purchased power percentage is a positive ratings factor.

The member/owner profile factors include percentage of residential sales, which is a positive factor for AEPCO. The equity capitalization of members would fall in the Baa category, or a relatively negative factor. The size rating factor is a strongly negative factor for AEPCO, both with regard to megawatt-hour sales and net property plant and equipment. These two rating factors are below investment grade for AEPCO, and have to be considered a negative rating factor for AEPCO.[1]

[1] Size is a qualitative factor used by Moody's to establish a credit risk profile which is different from using size as a unique risk factor in cost of equity estimation. The Commission denied a proposal to assign a size risk premium in Decision No. 64282 and found that a firm size phenomenon does not exist for regulated utilities in Decision No. 64727.

The nonfinancial rating factors evaluated here indicate that AEPCO carries significant levels of added risk due to its regulatory status, rate flexibility criteria, and small sales and asset bases. I believe that these factors indicate that AEPCO carries business risk in these areas at levels material enough to consider in the determination of a target DSC range.

Q. What do you consider to be an appropriate range for Debt Service Coverage for AEPCO to target?

A. I believe that an appropriate target range for AEPCO's DSC is 1.25 to 1.45. I would consider the lower bound of the range to be set by the theoretical realization of financial results consistent with a 1.25 DSC, which would translate into a lower investment grade credit rating. On the other hand, the non-financial criteria discussed above indicate that AEPCO carries characteristics of a credit risk profile that call for a higher targeted DSC of up to 1.45. I believe that a reasonable targeted DSC within this range should maintain the financial health of AEPCO.

Q. How does this recommended range compare to the actual financial metric results of G&Ts in recent years?

A. The CFC prepares operating and financial statistics for G&T cooperatives on an annual basis, presenting them in the Key Trend Ratio Analysis ("KTRA"). The KTRA provides data for G&Ts overall, as well as for four sub-categories of G&T businesses. One of the sub-categories is generation companies that generate more than one-half of their power requirements. This category describes AEPCO well. The financial metrics of DSC, TIER, and equity ratio are comparable among all cooperative generation companies.

Exhibit LCG-4 provides these three ratios for the KTRA generation group and all G&Ts for the years 2005 to 2008. Overall TIER and DSC levels improved significantly from

2005 to 2008. The realized DSC levels of both the cooperative generation comparison group and all G&Ts each increased to 1.34 in 2008 from previously lower levels. Exhibit LCG-4 compares recent DSC levels realized by cooperative generation companies and G&Ts with my target DSC range. The most recent realized DSC levels of 1.34 in 2008 fall squarely in the middle of my recommended target DSC range of 1.25 to 1.45. The KTRA information indicates that this recommended target range is reasonable and at the levels actually experienced by cooperative generation and G&T cooperatives.

RATE SUFFICIENCY

Q. Does AEPCO's request for a target DSC of 1.275 provide supporting information indicating that AEPCO will have a sufficient return and cash flow?

A. No. AEPCO has calculated its net margin with its proposed rates at only $3.2 million, which I believe is too thin from both a net margin and cash flow perspective. This thin level of operating and net margins provides little earnings cushion to cover unexpected operating problems and contingencies. It also does not provide sufficient cash generated by AEPCO's operations to meet its cash obligations. AEPCO's Schedules A-5 and E-3 show that, with the proposed rates in effect, net cash provided by operating activities would be only $3.6 million for the test year, as compared to net cash requirements of $21.2 million. The net annual cash shortfall would thus be about $17.6 million. The rate filing indicates that cash flow would not be adequate even if requested rates were approved.

I do not believe, however, that the cash situation is quite so dire on a going-forward basis. I have requested forecasted financial information from AEPCO to determine if AEPCO will have sufficient cash generation to meet its cash obligations in future years. These years include a greatly increased capital budget when compared with recent years.

Unfortunately, AEPCO has not been able to provide a recently-prepared financial forecast that I could review prior to preparing this testimony.

AEPCO has stated in its testimony that it has already experienced severe cash flow problems during the past few years, even while margins were strong. These cash shortages arose from temporary under-collections for fuel caused by volatile fuel prices, the high level of principal payments prior to extending debt maturities with the RUS, and the financing of increasing dollar levels of coal inventory. These inventory costs rose due to coal price increases and inventories that greatly exceeded target levels. The information that AEPCO provided led me to conclude that both the net margin and resulting cash flow proposed by AEPCO will not be sufficient to meet future needs.

Q. What potential problems may occur by targeting a "minimum level" DSC; i.e., one at the lower end of your range?

A. AEPCO's financial results could deteriorate quickly during the next few years, potentially wiping out its small requested net margin and causing additional cash requirements. Following the end of the test year, AEPCO plans capital expenditures of about $85 million during the following 36 months. The unrecovered financing costs of these capital expenditures would reduce earnings by about $500,000 in the first 12 months, $1.9 million in the second 12 months, and $3.5 million in the third 12 months. With its historical test year, AEPCO is also susceptible to any operating expense increases that may occur. For instance, a major plant outage and the replacement power costs required could also easily eliminate the net margin included in its rate request. AEPCO will also have to pay for mercury control chemicals that are not included in this rate filing. AEPCO estimates those at $600 thousand to $2 million annually. I expect that AEPCO will face great difficulty in earning the $3.2 million in annual net margins that it proposes.

Q. What are your target DSC, TIER, and net margin recommendations for AEPCO?

A. Based on the higher credit risk profile that I have identified for AEPCO, I recommend that rates be set based upon a DSC that is near the upper end of my recommended DSC range of 1.25 to 1.45. I recommend that a target DSC of 1.40 be adopted for rate setting purposes. This DSC level would produce net margins of about $5.5 million annually and a TIER ratio of 1.51.

Q. Does this conclude your Direct Testimony?

A. Yes.

Randall E. Vickroy

Areas of Specialization

Mr. Vickroy has over 25 years of experience in the utility industry, including fifteen years as a management consultant. He has managed and performed numerous high-level consulting assignments at companies and utility commissions in over 25 states. His areas of expertise include corporate finance and treasury management; capital markets and financing vehicles; utility industry restructuring; utility rates and pricing; non-regulated lines of business and affiliations; strategy and planning issues; asset valuations and decision-making; capital and expense budgeting and forecasting; corporate resource allocation; and financial and economic analysis.

Relevant Experience

Lead Consultant on electrical energy and capacity purchases and sales and hedging and capital budgeting on Liberty's management and operations audit of the electricity, natural gas, and steam operations of ConEd for the New York Public Service Commission.

Served as Lead Consultant in an audit of the fuel and purchased-power procurement practices and costs of Arizona Public Service Company for the Arizona Corporation Commission. Responsible for reviews of its contracting and supply-management practices for natural gas. His assignment in the Arizona project included an examination of the reasons for differences in off-system sales between Arizona Public Service, including specifically PNM and Salt River Project

Led the review of finance and the protection and insulation of the utility from parent and non-utility operations and finances on Liberty's focused and general management audits of NJR, New Jersey Natural Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues.

Lead Consultant in Liberty's audit of Duke Energy Carolinas for the North Carolina Utilities Commission, focusing on issues of compliance with regulatory conditions and code of conduct.

Led the review of finance and the protection and insulation of the utility from parent and non-utility operations and finances on Liberty's focused and general management audits of SJI, South Jersey Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues.

Lead for examination of financing and risk management on Liberty's focused audit of NUI Corporation and NUI Utilities. This audit included a detailed examination of the reasons for poor financial performance of non-utility operations, affect of affiliate operations, including commodity trading on utility credit and finance, downgrades of utility credit beneath investment grade, and retail and wholesale gas supply and trading operations. The audit included detailed examinations of financial results, sources and uses of funds, accounting systems and controls, credit intertwining, cash commingling, and affiliate transactions, among others. Liberty's examination included very detailed, transaction-level analyses of commodities trading undertaken by a utility affiliate both for its own account and for that of utility operations.

Served as Lead Consultant in Liberty's review of acquisitions of UniSource (Arizona) and Portland General Electric (Oregon) focusing on utility financial insulation, governance, service reliability, access to information, and community presence issues.

Lead Consultant in Liberty's comprehensive analysis of the ratemaking implications of Commonwealth Edison's Chicago electric service outages for the Illinois Commerce Commission. Responsible for investigating and analyzing ComEd's capital budgeting, resource allocation, project management, expenditure levels and rate base impacts for operations leading up to and in response to the outages.

Lead Consultant in Liberty's review of the financial integrity and earnings of Verizon New Jersey's rate regulated and competitive businesses for the New Jersey BPU. Responsible for the financial evaluation of VNJ's earnings, capital structure, rates of return, dividend policies, credit ratings, financial reporting, SEC reporting, and BPU surveillance reports.

Lead Consultant in Liberty's financial audit for ratemaking purposes of Verizon New Hampshire for the New Hampshire Public Utilities Commission. Responsible for a broad and comprehensive analysis of the financial status of VNH, including an audit of the books and records of the Verizon parent, in order to assist the commission in determining rate base, rates of return and appropriate adjustments for the test year.

Project Manager for the development and implementation of regulatory financial systems and models for deregulated ratemaking at Pacific Gas and Electric Company. The project involved developing regulatory strategy, California PSC earnings monitoring models, data bases, analytical models and reporting for all regulatory requirements of PG&E's regulated businesses.

Led the development of a framework and strategy to resolve all electric industry restructuring issues between the State of New Hampshire, Public Service Company of New Hampshire, and the NHPSC. Project included assessment and valuation of all key assets and development of a disposition strategy for all generation assets, contracts and obligations. The project also included the assessment of alternative rate paths; planning for the securitization and recovery of stranded costs; and the development of provisions for power supply purchases during a transition period.

Team leader for the review of the New York Power Authority's profitability, financial reporting, rate competitiveness, pricing policies, power plant economics and economic development programs in this management audit for the state of New York. NYPA is the largest generator and carrier of power in New York, providing over 25 percent of the electricity sold.

Team leader in providing consulting assistance to Kentucky Utilities in preparing its 1993 application for implementing an environmental surcharge. Responsibilities included analyzing legislation, analysis of capital expenditures, analysis of KU's Clean Air Act compliance plan, analysis of costs recoverable under the surcharge, and developing testimony, exhibits, special accounting systems, and rate tariffs.

Project Leader for providing consulting assistance to Big Rivers Electric in preparing its 1994 application for implementing an environmental surcharge. Responsibilities included a review and evaluation of the economics of a major investment in a flue gas scrubber, analysis of Big Rivers' Clean Air Act compliance plan, evaluating cost recoverable under the surcharge, and developing surcharge testimony, exhibits, accounting systems and rate tariffs.

Consultant in Liberty's management audit of GTE South - Kentucky for the Kentucky Public Service Commission. Responsible for the analysis of the financial-management of GTE as it relates to the operation of its GTE South subsidiary.

Lead Consultant in Liberty's management audit of Bell Atlantic - Pennsylvania and Bell Atlantic - District of Columbia for their respective commissions. Responsible for reviewing Bell Atlantic's capital structure, finance and controller functions, financial systems, and treasury operations. Focus areas included the impact of telephone industry competition on capital budgeting, financial management strategy, and treasury operations.

Leader for all financial areas in the review of affiliate transactions among Public Service Electric and Gas, its holding company parent, and the extensive diversified businesses of the holding company. Responsible for evaluating PSE&G's consolidated finance functions to determine whether the financial integrity, flexibility, and cost of capital of the regulated utility had been adversely affected by the activities of diversified affiliates. Work included the review and analysis of the long-term financing, cash management, direct and indirect credit support mechanisms, investor relations, and all transactions between and among the affiliates.

Led the review of finance, cash management, budgeting, and rates in Liberty's comprehensive management audit of Southern Connecticut Gas for the Connecticut DPUC. Responsibilities included operational audits of all finance, regulatory and budgeting processes of SCG.

Led the review of the finance, cash management, budgeting, accounting and rate functions in Liberty's comprehensive management audit of Connecticut Natural Gas for the Connecticut DPUC. Work also included a focus on the financial impacts of CNG's non-regulated businesses, which includes a large steam system in downtown Hartford.

Led the review of the finance, cash management, budgeting, rates, and tax functions in Liberty's comprehensive management audit of Yankee Gas for the Connecticut DPUC. Evaluation included an in-depth analysis of the effectiveness of Yankee's capital and expense budgeting processes and the integration of market and competitive components into these processes.

Led the review of the finance, regulatory and accounting functions in Liberty's management audit of United Cities Gas for the Tennessee Public Service Commission. Responsibilities included a review of all financial functional areas, as well as a review of the impact of all affiliate transactions between the regulated and non-regulated businesses.

Led the evaluation of the financial relationships between Hawaiian Electric Industries and Hawaiian Electric Company for the Hawaii Department of Commerce and Consumer Affairs. The focus of the review was the credit and financial support provided by the utility company to the holding company and its diversified businesses.

Led the review and analysis of corporate governance, financial relationships and affiliate transactions between Virginia Power and its parent, Dominion Resources for the Virginia State Corporation Commission. The review included an evaluation of all utility and non-utility financing, governance and economic impacts. The engagement was in response to a well-publicized dispute between the holding company and Virginia Power.

Led the consulting and monitoring of contracting for electric supply by Western Massachusetts Power following the sale of its generation assets under electric deregulation.

Led the review and evaluation of the financial management practices of a major utility holding company. Engagement included an assessment of overall financial management and crisis-liquidity plans; strategic and business planning; asset valuations and their accounting impacts upon deregulation; independent power contract buy-downs; and rate reduction strategies.

Led the evaluation and recommendation of strategic lines of business for a major municipal utility facing industry deregulation.

Led the development of a strategic framework for the establishment and growth of non-regulated businesses for a major international electric holding company.

Led the development, analysis, and recommendation of alternative electric generation and power resource strategies for a regional generation and transmission company in preparation for electric deregulation.

Led the review and evaluation of all utility and non-utility financing, financial relationships, and affiliate transactions between a major utility holding company and its electric company subsidiary.

Leader for all financial areas in the evaluation of the diversified businesses of a major utility holding company. Engagement determined the impact on financial integrity, financial flexibility, credit mechanisms, and the cost of capital of the substantially diversified businesses of the holding company.

Led the development of an overall gas business strategy, capital asset allocation methods, financial analysis programs and gas main extension policy for a Midwestern combination utility.

Education

M.B.A., Finance, University of Denver

B.A., Business Administration, Monmouth College

Exhibit LCG-2

Arizona Electric Power Cooperative, Inc.
Computation of TIER, DSCR and Equity Ratios
Twelve Months Ended December 31, 2000 through 2009
Response to STF 4.112

Description	12 Mos. Ended 12/31/00	12 Mos. Ended 12/31/01	12 Mos. Ended 12/31/02	12 Mos. Ended 12/31/03	12 Mos. Ended 12/31/04	12 Mos. Ended 12/31/05	12 Mos. Ended 12/31/06	12 Mos. Ended 12/31/2007 (1)	12 Mos. Ended 12/31/08	12 Mos. Ended 12/31/09
Times Interest Earned Ratio Calculation:										
Net Patronage Capital or Margins	$ 12,070,720	$ 10,431,220	$ 3,898,571	$ (7,048,847)	$ 293,222	$ 426,624	$ 13,980,512	$ 20,549,535	$ 17,355,771	$ 9,956,925
Interest on Long-Term Debt	18,251,166	16,050,770	12,825,566	12,200,997	12,562,525	12,877,640	12,401,645	11,347,878	10,459,715	10,622,133
Total	$ 30,321,886	$ 26,481,990	$ 16,724,137	$ 5,152,150	$ 12,855,747	$ 13,304,264	$ 26,382,157	$ 31,897,413	$ 27,815,486	$ 20,579,058
Times Interest Earned Ratio	1.66	1.65	1.30	0.42	1.02	1.03	2.13	2.81	2.66	1.94
Debt Service Coverage Ratio Calculation:										
Net Patronage Capital or Margins	$ 12,070,720	$ 10,431,220	$ 3,898,571	$ (7,048,847)	$ 293,222	$ 426,624	$ 13,980,512	$ 20,549,535	$ 17,355,771	$ 9,956,925
Depreciation & Amortization Expense	11,223,824	11,519,596	7,808,510	8,774,101	8,911,221	8,432,257	7,466,357	7,985,116	8,069,925	8,818,475
Interest on Long-Term Debt	18,251,166	16,050,770	12,825,566	12,200,997	12,562,525	12,877,640	12,401,645	11,347,878	10,459,715	10,622,133
Total	$ 41,545,710	$ 38,001,586	$ 24,532,647	$ 13,926,251	$ 21,766,968	$ 21,736,521	$ 33,848,514	$ 39,882,529	$ 35,885,411	$ 29,397,533
Principal Payments	$ 15,613,967	$ 13,769,035	$ 11,830,358	$ 12,552,536	$ 13,541,855	$ 14,989,167	$ 16,815,465	$ 17,801,025	$ 16,478,234	$ 6,673,550
Interest on Long Term Debt	18,251,166	16,050,770	12,825,566	12,200,997	12,562,525	12,877,640	12,401,645	11,347,878	10,459,715	10,622,133
Total	$ 33,865,133	$ 29,819,805	$ 24,655,924	$ 24,753,552	$ 26,104,380	$ 27,866,807	$ 29,217,110	$ 29,148,903	$ 26,937,949	$ 17,295,683
Debt Service Coverage Ratio	1.23	1.27	1.00	0.56	0.83	0.78	1.16	1.37	1.33	1.70
Equity as a Percent of Total Capitalization:										
Margins and Equity	$ 7,971,346	$ 13,904,998	$ 17,803,568	$ 10,754,721	$ 11,047,943	$ 11,474,569	$ 25,455,081	$ 57,202,298	$ 74,558,070	$ 84,514,994
Short Term Debt	5,058,217	4,584,386	4,978,804	1,834,000	3,948,668	15,246,584	22,873,845	24,699,949	17,534,537	22,442,010
Long Term Debt	302,891,350	202,660,477	210,418,005	212,811,754	214,299,718	205,357,382	189,137,907	148,844,055	172,518,677	180,049,657
Total Capitalization	$ 315,920,913	$ 221,149,861	$ 233,200,377	$ 225,400,475	$ 229,296,329	$ 232,078,535	$ 237,466,833	$ 230,746,302	$ 264,611,284	$ 287,006,661
Equity Ratio Percentage	2.52%	6.29%	7.63%	4.77%	4.82%	4.94%	10.72%	24.79%	28.18%	29.45%

(1) Margins and Equity as of December 31, 2007 reflect an $11.2 million adjustment for change in accounting for overhaul costs. See the audited financial statements for 2007 for more information.

Exhibit LCG-3

Credit Rating Financial Metrics for G&Ts

Exhibit LCG-3

	A Rated Range	*Baa Rated Range*	*Mid-point of A and Baa Ranges*	*AEPCO ProForma with Rate Request*
Funds From Operations/Debt (FFO/Debt)	6% -10%	3% - 6%	6.50%	5.55%
Funds From Operations/Interest (FFO/Interest)	2.0X - 2.5X	1.5X - 2.0X	2.0X	1.97X
Equity/Total Capitalization	20% - 35%	5% - 20%	20%	27.94%
Debt Service Coverage (DSC)	1.2X - 1.4X	1.1X - 1.2X	1.25X	1.275X
Times Interest Earned Ratio (TIER)	1.2X - 1.4X	1.1X - 1.2X	1.25X	1.30X

Columns A and B from response to STF 4.115, "U.S. Electric Generation & Transmission Cooperatives", Moody's Investors Service, December 2009.

Exhibit LCG-4

Exhibit LC

Comparison of KTRA G&T Cooperative Key Financial Indicators
With Liberty Consulting Cost of Capital Recommendation

	2005	2006	2007	2008	
Debt Service Coverage (DSC)					
Generation Cooperative Group - KTRA	1.01X	1.08X	1.21X	1.34X	
All G&T Cooperatives - KTRA	1.12X	1.05X	1.25X	1.34X	
AEPCO	0.78X	1.16X	1.37X	1.33X	
Liberty Recommended DSC Range for AEPCO (For future application)					1.25X - 1.4
Times Interest Earned Ratio					
Generation Cooperative Group - KTRA	1.29X	1.46X	1.50X	1.57X	
All G&T Cooperatives - KTRA	1.33X	1.46X	1.46X	1.73X	
AEPCO	1.03X	2.13X	2.81X	2.66X	
Liberty Recommended TIER Range for AEPCO (For future application)					1.26X - 1.5

KTRA information from the response to STF 4.116