BEFORE THE ARIZONA CORPORATION COMMISSION

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

E-01773A-09-0472

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-_____ **APPLICATION**

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

The Arizona Electric Power Cooperative, Inc. ("AEPCO"), by and through its undersigned attorneys, in support of its Application states as follows:

1. AEPCO is a non-profit electric generation cooperative which serves the power needs of its four all-requirements ("ARM") and two partial-requirements ("PRM") Arizona 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.

2. AEPCO's 14-member Board of Directors oversees all aspects of its operations. Twelve members of the Board are elected by AEPCO's six Class A Member distribution cooperatives. The distribution cooperatives' Board members are elected annually by their retail member/consumers. AEPCO's Board has authorized the filing of this rate application.

3. Pursuant to the requirements of A.A.C. R14-2-103, submitted herewith and incorporated herein are the detailed filing requirements Schedules. Also submitted are the Direct

Testimonies of Messrs. Minson, Pierson and Goble in support of this Application. In summary, the Schedules and Testimony support AEPCO's request for a 2.83% decrease in ARM rates and a 5.39% increase in PRM rates. Those rates produce an overall rate increase of 2.41%, a Debt Service Coverage Ratio of 1.35 and operating margins of approximately $3.4 million.

4. AEPCO's current rates were authorized by the Commission in Decision No. 68071 and became effective on September 1, 2005. In that Decision, the Commission 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, which calculated to a July 1, 2009 deadline. 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 ended March 31, 2009.

5. The impact of the new wholesale rates on the retail consumer is difficult to estimate precisely because, among other things, AEPCO's members have different retail rate levels and structures to which these wholesale rates are applied. In general, however, generation costs account for approximately 55% of the end user's rates. On that assumption, AEPCO estimates a 1.6% decrease for all-requirements customers and a 3% increase for partial-requirements members.

6. AEPCO requests that the Commission authorize the following rates. For ARMs: a demand rate of $14.05/kW month and three energy rates: a Base Resources energy rate of $0.03236/kWh; an Other Existing Resources energy rate of $0.06730/kWh; and an Additional All-requirements Resources energy rate of $0.07341/kWh. Requested revised rates for Mohave Electric Cooperative, Inc. ("MEC") are: a fixed charge of $772,376 per month; a fixed O&M charge of $1,410,263 per month; and two energy rates: a Base Resources energy rate of

$0.03216/kWh and an Other Existing Resources energy rate of $0.06879/kWh. Finally, AEPCO requests revised rates for partial-requirements member SSVEC as follows: a fixed charge of $683,919 per month; a fixed O&M charge of $1,248,752 per month; and two energy rates: a Base Resources energy rate of $0.03230/kWh and an Other Existing Resources energy rate of $0.06676/kWh.

7. AEPCO also requests that the Commission approve continuance of the purchased power and fuel adjustor clause ("PPFAC") with modifications as described in the testimony submitted with this Application. AEPCO's current PPFAC is scheduled to expire in August 2009. (Decision No. 68071, Fifth Ordering Paragraph, Finding 35.) By separate motion, AEPCO will request the PPFAC continue pending and subject to the Commission's action in this case.

8. Finally, in compliance with Finding of Fact 60 in Decision No. 68071, AEPCO expenses in relation to test year service to Class B members City of Mesa ("Mesa") and Salt River Project ("SRP") are stated in columns 3 and 4, pp. 3-4, Schedule C-2 of the Schedules. Also, as discussed in Messrs. Minson and Pierson's direct testimonies, both the Mesa and SRP contracts have been adjusted out of the test year because the contracts have expired or will expire before rates take effect on January 1, 2011. Class D member Valley Electric Association ("Valley") does not take firm wholesale electric service, so there are no firm sales-for-resale costs associated with Valley. As to costs by demand and energy categorization, their categorization is addressed in Schedules G-6, page 5 and G-4, page 1 and, given the wholesale nature of AEPCO's customers, there are no identifiable customer costs. Finally, see Exhibit A which shows the derivation of AEPCO related ancillary service charges in a manner consistent with FERC definitions.

Having fully stated its Application, AEPCO requests that the Commission enter its Order:

1. Approving the revised rates requested herein;

2. Approving continuation of the PPFAC with the modifications requested;

3. If necessary, authorizing amendments to the MEC and SSVEC PRM agreements to conform to the revised rates and other relief approved by the Commission; and

4. Granting AEPCO such other and further relief as it deems appropriate under the premises.

RESPECTFULLY SUBMITTED this 1st day of October, 2009.

GALLAGHER & KENNEDY, P.A.

By [signature]
Michael M. Grant
Jennifer A. Ratcliff
2575 East Camelback Road
Phoenix, Arizona 85016-9225
Attorneys for Arizona Electric Power Cooperative, Inc.

Original and thirteen copies of this Application, Schedules and Direct Testimony filed this 1st day of October, 2009, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of this Application and Direct Testimony hand delivered this 1st day of October, 2009, to:

Commissioner Kristin K. Mayes, Chairman
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

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Phoenix, Arizona 85007

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Phoenix, Arizona 85007

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10421-59/2202957v2

EXHIBIT A

Southwest Transmission Cooperative/Arizona Electric Power Cooperative

Derivation of Transmission Rates, Control Area Services and Revenue Requirements

Twelve Months Ended March 31, 2009

Schedule 2: COST OF REACTIVE POWER (VAR) PRODUCTION

AEPCO system investment in Power Production Facilities				
		Orig Cost	Net	
1 Total production plant in service		$405,097,077	$189,399,425	Page 7
2 Turbogenerator Systems		$54,638,869	$23,457,593	Page 5
3 Accessory Electric Equipment		$20,143,173	$8,647,880	Page 5
Separation of Production Plant Allocation to VAR Production		$74,782,041		
4 Generator and Exciter Systems	#2*(1-Power Factor)		$3,353,691	
5 Accessory Electric Equipment	#3*(1-Power Factor)		$1,236,372	
6 Other Power Production Facilities	1-4-5*(.25%)		$462,023	
7 Total Facilities Allocated to VAR Production			$5,052,086	
Annualized Costs Facilities Allocated to VAR Production	7*Int+DSCR	1.350	$403,017	
		7.977%		
Rates For VAR Production		12 CP	1 CP	
		506.12	683.7	
	$/kW/year	$0.796	$0.589	
	$/kW/month	$0.066	$0.049	

Power Factor	Gross Nameplate output in kW	Pwr Factor Generator Name plate	weighted Power factor	EAF Equivalent Availability Factor	Weighted Average
steam unit 1	77,400	0.85	10.885%	77.82%	9.97%
steam unit 2	195,000	0.85	27.424%	91.22%	29.43%
steam unit 3	195,000	0.85	27.424%	92.69%	29.90%
gas turbine 1	10,000	0.85	1.406%	83.20%	1.38%
gas turbine 2	20,000	0.9	2.978%	97.52%	3.23%
gas turbine 3	65,000	0.9	9.679%	96.26%	10.35%
gas turbine 4	42,000	0.85	5.907%	62.66%	4.35%
	604,400		85.703%		88.61%
(1-Power factor)			14.297%		

Southwest Transmission Cooperative/Arizona Electric Power Cooperative

Derivation of Transmission Rates, Control Area Services and Revenue Requirements

Twelve Months Ended March 31, 2009

Schedules 3, 5 & 6: APACHE STATION COST SUPPORT BY UNIT

Gen. Units	name plate SRSG RATING	Prod Invest.	Int plt, a/c 106,107 Transm,GP	Accum Depreciation + Retirement WIP	Working Capital	net. Prod. Invest less TURBO	Prod $/kW	O&M Exp	A&G	Taxes	Depreciation	Annual Carrying Costs	Annual Revenue Rqt	Annual RevRqt/kW
			$50,496,560	$6,686,195	$21,814,465			$12,871,680	$12,054,892	$2,933,343	$7,693,790	$16,728,980		
ST1	70,000	$ 22,196,122	$ 3,021,820	$ 19,397,858	$ 1,305,423	$ 25,609,185	$ 366	$ 770,268	$ 721,390	$ 175,537	$ 460,412	$ 1,001,097	$ 3,128,705	44.70
ST2	188,000	158,500,501	21,578,540	89,808,077	9,321,909	175,068,030	931	5,500,416	5,151,380	1,253,496	3,287,764	7,148,744	22,341,800	118.84
ST3	188,000	147,868,356	20,131,061	82,477,954	8,696,599	162,459,584	864	5,131,450	4,805,828	1,169,412	3,067,222	6,669,209	20,843,122	110.87
IC1/GT1	9,000	1,946,118	264,948	1,835,175	114,457	2,325,524	258	67,536	63,250	15,391	40,368	87,774	274,320	30.48
GT2	17,000	3,077,974	419,041	2,596,304	181,025	3,524,967	207	106,814	100,036	24,342	63,846	138,824	433,863	25.52
GT3	64,000	8,614,275	1,172,763	6,330,170	506,632	9,140,287	143	298,940	279,970	68,126	178,685	388,524	1,214,245	18.97
GT4	40,000	28,708,212	3,908,387	5,898,018	1,688,419	32,248,226	806	996,256	933,038	410,000	595,492	1,294,808	4,229,593	105.74
	576,000	$ 370,911,558	$ 50,496,560	$ 208,343,556	$ 21,814,465	$ 410,375,802		$ 12,871,680	$ 12,054,892	$ 3,116,305	$ 7,693,790	$ 16,728,980	$ 52,465,647	
			$ 421,408,118											

		turbo equip 314,315,344,345	Plant dep reserve assignable to gen units	Turbo Depreciation Reserve	Net turbo plant
ST1	70,000	$ 6,344,228	$ (18,997,743)	$ (5,430,049)	$ 914,180
ST2	188,000	31,751,046	(86,950,886)	(17,418,125)	14,332,921
ST3	188,000	30,932,169	(79,812,422)	(16,695,738)	14,236,431
IC1/GT1	9,000	-	(1,800,094)	-	-
GT2	17,000	877,136	(2,540,819)	(724,062)	153,074
GT3	64,000	4,072,970	(6,174,886)	(2,919,587)	1,153,383
GT4	40,000	2,531,189	(5,380,513)	(474,397)	2,056,792
TOTAL	576000	$ 76,508,736	$ (201,657,361)	$ (43,661,958)	$ 32,846,781

Replacement

	kW	Cost/kW	Annual $
GT1	9,000	$105.740	$951,659
ST1	70,000	$44.696	$3,128,705
GT3	64,000	$18.973	$1,214,245
	143,000		$5,294,608
	$/kW/year		$37.025
	$/kW/month		$3.085

Schedule 3

Regulation

	kW Capacity	Cost/kW	Annual $
ST2	188,000	$118.839	$22,341,800
ST3	188,000	$110.868	$20,843,122
ST1	70,000	$44.696	$3,128,705
	446,000		$46,313,626
	$/kW/year		$103.842
	$/kW/month		$8.654

Schedule 5

Spinning

	kW Capacity	Cost/kW	Annual $
ST2	188,000	$118.839	$22,341,800
ST3	188,000	$110.868	$20,843,122
	376,000		$43,184,921
	$/kW/year		$114.854
	$/kW/month		$9.571

Schedule 6

Supplemental

	kW Capacity	Cost/kW	Annual $
GT4	40,000	$105.740	$4,229,593
GT2	17,000	$25.521	$433,863
	57,000		$4,663,456
	$/kW/year		$81.815
	$/kW/month		$6.818

Southwest Transmission Cooperative/Arizona Electric Power Cooperative

Derivation of Transmission Rates, Control Area Services and Revenue Requirements

Twelve Months Ended March 31, 2009

AEPCO PRODUCTION PLANT ORIGINAL COST AND NET PLANT SUMMARY FOR ANCILLARY SERVICES WORKSHEETS

INTANGIBLE	$	5,290		
PRODUCTION				
STEAM 1		22,196,122		
STEAM 2		158,500,501		
STEAM 3		147,868,356		
GT 1		1,946,118		
GT 2		3,077,974		
GT 3		8,614,275		
GT 4		28,708,212		
Transmissio		2,889,491		
GENERAL PLANT		19,286,132		
A/C 106		1,998,986		
A/C 107@50%		9,992,383		
ACQUISITION ADJ		13,238		
TOTAL			$ 405,097,077	
DEPRECIATION & AMORTIZATION RESERVE				
PRODUCTION				
STEAM 1	$	(18,997,743)		
STEAM 2		(86,950,886)		
STEAM 3		(79,812,422)		
GT 1		(1,800,094)		
GT 2		(2,540,819)		
GT 3		(6,174,886)		
GT 4		(5,380,513)		
GENERAL & INTANGI		(10,016,425)		
TRANSMISSION PLAN		(1,580,842)		
AMORTIZATION		(2,443,024)		
TOTAL			$ (215,697,652)	
NET PRODUCTION PLANT	$	184,347,339	less turbo eqp.	$ 5,052,086
WORKING CAPITAL	$	21,814,465		
RETIREMENT WIP	$	3,547,307		
PRODUCTION PLANT RATE BASE			$ 209,709,111	
EXPENSE ALLOCATION				
PRODUCTION OP	$	12,748,120		
PRODUCTION MNT		18,780,152		
OTHER		2,591,246		
* TRANSMISSION EXP		4,516,966		
A&G		12,455,363		
TAXES		2,933,343		
DEP EXP		8,348,168		
TOTAL			$ 62,373,358	

PRODUCTION CAPABILITY (kW on SRSG Basis)		576,000
NET INVESTMENT		$209,709,111
INTEREST & DSCR page 6	1.35	7.977%
ANNUAL CARRYING COSTS		$ 16,728,980
ANNUAL EXPENSES		$ 62,373,358
PLANT ANNUAL REVENUE REQUIREMENTS		$ 79,102,338
PLANT ANNUAL COSTS/KW		$ 137.33
MONTH		$ 11.44
Gen Plant Fixed Charge Rate (Rev Req't/ Rate Base)		37.720%
PURCHASE POWER CAPACITY (pro-forma 2009)		Test Year Actual
Purch Pwr Avg Contract Demand kW	300,000	300,000
Southpoint	150,000	150,000
Griffith	150,000	150000
Purch Pwr Annual Demand Charges	$2,365,328	$2,365,328
Southpoint	$1,389,300	$1,389,300
Griffith	$976,028	$976,028
Purch Pwr Monthly Costs/kW	$7.884	7.88
Southpoint	$9.262	$9.262
Griffith	$6.507	$6.507
PLANT + PP Annual Rev Req't	$81,467,666	$81,467,666
Annual cost/kW	$93.000	$93.000
Monthly cost/kw	$7.750	$7.750

Southwest Transmission Cooperative/Arizona Electric Power Cooperative
Derivation of Transmission Rates, Control Area Services and Revenue Requirements

Twelve Months Ended March 31, 2009

SCHEDULE 4: ENERGY IMBALANCE

Energy Imbalance Cost = Accts 501+547+ e-charge a/c 555/kwh

Fuel	501/547	$	88,508,998
Purchased Power	555 Energy Only		13,428,375
Non-Firm Wheeling			2,880
Firm Contracts Energy Revenues			(2,448,992)
Economy Sales Energy Revenues			(3,952,272)
		$	95,538,990

Total sales		2,604,463,779 kWh
	$	36.68 $/MWh

Exhibit A

Arizona Electric Power Cooperative, Inc.

P.O. Box 670 • Benson, Arizona 85602-0670 • Phone 520-586-3631

BEFORE THE ARIZONA CORPORATION COMMISSION

TESTIMONY

IN SUPPORT OF

THE ARIZONA ELECTRIC POWER COOPERATIVE, INC.

RATE APPLICATION

DOCKET NO. E-01773A

OCTOBER 2009

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Testimony	Tab
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Gary L. Goble	**C**

A

DIRECT TESTIMONY OF DIRK MINSON
ON BEHALF OF
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
GENERAL RATES APPLICATION

INTRODUCTION

Q. Please state your name and business address.

A. My name is Dirk Minson. My business address is 1000 South Highway 80, Benson, Arizona 85602.

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

A. I am the Chief Financial Officer of the Arizona Electric Power Cooperative, Inc. ("AEPCO"). As Chief Financial Officer, I serve on the Executive Management Team and report directly to the Chief Executive Officer. My specific responsibilities and duties include the accounting functions of the Cooperative, including establishing fiscal policy, procedure development and implementation of appropriate financial controls. Additional responsibilities include financial planning, rate design development and implementation, corporate treasury functions, as well as cash and working capital management and inventory control.

Q. Please briefly describe your educational background and work-related experience.

A. I hold a B.S. Degree in Business Administration from Kansas State University and an M.B.A. from the University of Missouri. My entire 34-year career has been spent working directly or indirectly for electric cooperative utilities. I began my employment with AEPCO in 1982 and was promoted to the position of Chief Financial Officer in May 1990.

Q. Mr. Minson, what is the purpose of your testimony?

A. I will provide the Commission information concerning AEPCO, its membership structure, its Board review and approval process for this rate filing and its rate history. I'll also describe generally the rate request and certain issues and other requests concerning it. Gary Pierson, our Manager of Financial Services, will testify specifically concerning the A-F rate filing schedules. Gary Goble of Management Applications Consulting testifies in support of the G and H rate filing schedules.

BACKGROUND

Q. Mr. Minson, please describe AEPCO.

A. AEPCO is a non-profit, generation cooperative which serves the wholesale power needs of its four all-requirements ("ARM") and two partial-requirements ("PRM") Class A Member distribution cooperatives ("distribution cooperatives"). The distribution cooperatives provide electricity at retail to their member owners which AEPCO generates or purchases at wholesale. We have one Class A ARM in south-central California—Anza Electric Cooperative, Inc. The three Arizona ARMs are Duncan Valley Electric Cooperative, Inc., Graham County Electric Cooperative, Inc. and Trico Electric Cooperative, Inc. Our two PRMs are Mohave Electric Cooperative, Inc. ("MEC") and Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC"). The Arizona distribution cooperatives are also regulated by the Commission.

Q. What is the difference between an ARM and a PRM?

A. As the name implies, an all-requirements member or ARM has a contract with AEPCO which requires it to buy and AEPCO to plan for and furnish all of its present and future power requirements. A partial-requirements member or PRM, instead, contracts with AEPCO to furnish only a portion of its retail electricity requirements. That member then plans for and secures from AEPCO or others the balance of its electricity needs. MEC became a PRM in 2001 as part of AEPCO's restructuring, which the Commission approved in Decision No. 63868. SSVEC became a PRM on January 1, 2008. That conversion was approved by the Commission in Decision No. 70105.

Q. Does AEPCO have other members?

A. Yes. The City of Mesa was a Class B Member during a portion of the test year. But, its contract to purchase 15 MW of power and energy from AEPCO expired on December 31, 2008 and it no longer is a member. The Salt River Project is also a Class B AEPCO Member. However, its firm 100 MW electric service purchase agreement with AEPCO will expire next year on December 31, 2010. At that time, its membership will cease. Finally, Valley Electric Association became a Class D Member in 2007. It has a service contract for scheduling and trading services.

Q. How does AEPCO obtain the power and energy it supplies to its members and for firm contract sales?

A. Most of it is produced at our Apache Generating Station located near Wilcox, Arizona. We have approximately 560 MWs of coal and natural gas fired capacity. To meet our members' needs or where it is more economical to do so, we also enter into other power purchase arrangements including short- and long-term purchase agreements with other utilities. For example, during the test period, AEPCO had a 15 MW, year-round contract with Public Service Company of New Mexico which expired on December 31, 2008.

Q. How is AEPCO governed?

A. AEPCO's Board of Directors oversees all aspects of our operations. It is comprised of 14 members. Twelve of the Board members (two per Class A Member) are designated as the distribution cooperatives' representatives by the distribution cooperative Boards. Those Boards, in turn, are elected by their retail member/consumers. The remaining two Board members represent the Class B and Class D Members.

Q. Mr. Minson, please describe AEPCO's recent rate history.

A. AEPCO's current rates were authorized by the Commission in Decision No. 68071 and became effective on September 1, 2005. In addition, the Decision approved implementation of a Purchased Power and Fuel Adjustor Clause ("PPFAC"). Decision No. 68071 also ordered AEPCO to file a rate case six months after SSVEC had completed a full calendar year as a partial-requirements member, *i.e.*, July 1, 2009. On April 13, 2009, AEPCO filed a request with the Commission to extend the filing date from July 1 to October 1 in order to facilitate further discussions on cost allocation and rate design issues among its all- and partial-requirements members. The Commission granted AEPCO's request in Decision No. 71112 and authorized AEPCO to file its rate case on October 1 based upon a test year ending March 31, 2009.

Q. Did AEPCO's Board approve this rate filing and the other requests AEPCO is presenting in this application?

A. Yes.

The process of Board review began this spring. Several Board meetings were held to discuss the need for and the elements of AEPCO's rate filing. In addition, meetings were held with the distribution cooperatives' staffs and consultants to review revenue requirement aspects of the filing and a committee of representatives of Class A Members and the AEPCO staff also discussed certain cost allocation and rate design issues. As we explained in seeking the extension for the rate filing from July 1 to October 1, our purpose in conducting these multiple meetings was to develop as much consensus on as many issues as possible. We did make significant progress on that front.

AEPCO's Board of Directors approved the filing of this rate case on a non-unanimous basis during its September 2009 meeting. The committee formed to address allocation and rate design issues has not yet reached a final resolution of all issues, but it is attempting to complete a rate settlement agreement on or before December 1, 2009.

We are hopeful that the members will be able to resolve the remaining cost allocation and rate design issues. However, regardless of that outcome, as I'll explain, for its own revenue requirements, PPFAC and other needs, AEPCO must make this filing now so that new rates can take effect January 1, 2011. We have also prepared this filing based upon cost allocation and rate design principles which we believe are fair and just—taking into account where possible the input of our members on these issues. Mr. Goble discusses these subjects in much greater detail.

OVERVIEW OF FILING

Q. Please summarize AEPCO's rate request.

A. Messrs. Pierson and Goble testify concerning the specifics of the request. But, in general, AEPCO requests an overall 2.41% increase in its revenue requirements, which is a blend of a 2.83% decrease in revenues from all-requirements members and a 5.39% increase in revenues from its partial-requirements members. AEPCO further requests that the new rates take effect January 1, 2011 and that AEPCO's PPFAC be continued beyond its currently scheduled expiration date of August 17, 2010.

Q. Why is there a difference between the rate requests?

A. In several respects, the rate filing is based upon certain cost causation principles that were developed by the rate design committee. One of these principles involved a change in the methodology by which operations and maintenance expenses were allocated to the all- and partial-requirements customers. Using an allocation method based upon allocated capacity percentages as defined in the respective partial requirements agreements rather than a method based upon the percentage of kW month billing units to total kW month billing units results in a greater percentage of operations and maintenance expenses being assigned to the partial-requirements customers. That is the primary reason for the difference between the rate requests.

Q. Do all Class A Members get the benefit of whatever cost recoveries and margins are made on sales to others by AEPCO?

A. Yes. The first step in our rate determination process is to credit to the benefit of all members whatever cost recoveries and margins that AEPCO achieves in its contract and economy sales to others. Thus, the proceeds of these sales to others are used to reduce the distribution cooperatives' cost of service and, therefore, the rates for generation service which their retail members have to pay.

Q. **Can you estimate the impact that AEPCO's proposed rate increase would have on the retail member/owner's bill?**

A. That is difficult because the distribution cooperatives have different retail rates and varying rate structures. However, generation service accounts for about 55% of the costs of the total delivered rate at retail. Assuming a residential rate of 14 cents per kWh, on average eight cents of that rate would be attributable to AEPCO's generation service. Therefore, we estimate that an ARM residential consumer using 1,000 kWh per month would see approximately a $2.00 decrease in the monthly bill and a PRM residential consumer using the same amount would see about a $4.00 increase in the monthly bill as a result of this rate request.

Q. **Why is this rate increase necessary?**

A. Obviously, AEPCO is subject to the same kind of inflationary pressures which affect all utilities and businesses in general. Many of those costs have increased since the 2003 test year used in our last rate case. In addition to that, 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 costs 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. 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.

Q. **Did the foregoing four factors affect AEPCO's financial performance in 2008 and 2009?**

A. Yes. AEPCO is already experiencing the effects of the increase in coal costs, higher maintenance outage overhaul costs and the expirations of the Mesa sales and PNM purchase contracts. The revenue and cost impacts resulting from expiration of the Salt River Project contract and the new mercury control chemical costs will commence on January 1, 2011. That is why we are requesting that the new rates not take effect until that date.

Q. **What level of margins is AEPCO requesting in this rate application?**

A. AEPCO is requesting operating margins of $3.4 million. On a cash basis, the requested margins would generate approximately $5.0 million of working capital on an annual basis. AEPCO has reviewed its working capital needs going forward and determined that approximately $20 million in working capital is and will be necessary to support operational requirements. The requested small level of margins will begin to build toward that working capital level over the next several years.

Although AEPCO had positive margins from 2005 to 2008, it did not build higher levels of working capital. AEPCO's working capital was severely strained over that period—funding, among other things, under-collections in the fuel bank caused by volatile fuel costs; paying for a principal "bubble" caused by required principal payments which exceeded the depreciation levels built into current rates; and providing the substantial sums needed to cover its construction costs until loan funds can be drawn to reimburse expenditures when those construction projects are finally completed. For example, our construction expenditures as of March 31 of this year were almost $26 million—more than seven times the requested operating margin amount.

As a result of these cash and working capital demands, since 2005, AEPCO has had to use its operating line of credit extensively. It hit a high month-end drawn balance on the credit line of about $19 million in 2006. As of March 31, 2009, AEPCO still had an outstanding drawn balance of $15.8 million on that line. Currently, the balance is down to approximately $8.0 million. The requested margins will allow AEPCO to continue to reduce its line of credit balance and gradually build the necessary level of working capital that it needs to fund operations. Those margins will also reduce the interest expense and the associated cost of service which our members must pay.

OTHER ISSUES

Q. Mr. Minson, is AEPCO also requesting continuation of its PPFAC in this proceeding?

A. Absolutely. Mr. Pierson discusses the details of that request in his testimony and Mr. Goble sponsors the PPFAC bases in his testimony. As AEPCO's CFO, I can't stress strongly enough the vital role the PPFAC has played since AEPCO's last rate case in assuring literally that the lights stayed on in rural Arizona. Even with the clause, as I just discussed, our operating margins, available cash and line of credit were strained to the breaking point in 2006 and 2007. While the markets have calmed somewhat from those extremes, they still remain very volatile. For example, while we were negotiating a new agreement to replace our expiring coal contract, Powder River Basin coal prices moved up more than 50% from early 2007 to the end of 2008 and the price of Uinta Basin coal from Colorado more than doubled. Conversely, in just the past year, there has been a natural gas price decrease of 80% from $9.50/Dth in April 2009 from the San Juan Blanco Basin to $1.94/Dth in September 2009. While that's obviously good news currently, it also reinforces the facts that very volatile fuel prices continue and the PPFAC is critical to continue to address them.

AEPCO is also concerned with the potential magnitude of carbon taxes, cap and trade allowances or similar carbon levies that are being proposed in Congress. We also ask that AEPCO be authorized to recover these costs, if they materialize, through the PPFAC.

Q. Are there any events that may require AEPCO to supplement or revise the rate relief requested in this rate case?

A. Yes. We have made a labor expense adjustment in this filing to reflect an increase in contributions that AEPCO must pay to the National Rural Electric Cooperative Association ("NRECA") for participation in its Retirement and Security Program (AEPCO's pension plan for employees). It's possible that AEPCO may have to make additional contributions in 2010 and/or 2011 in the form of a Deficit Recovery Charge dependent upon NRECA's annual evaluation of the market value of the program's investments. If that occurs, we may file an amendment on that subject. Also, the discussions I mentioned previously among our members may or may not require an alteration to our request.

CONCLUSION

Q. Do you have any concluding remarks?

A. I would ask that the Commission enter its Order authorizing the implementation as of January 1, 2011 of the all-requirements and partial-requirements rates we have requested. We'd also ask that the Commission approve continuation of the PPFAC with the modifications discussed.

Q. Does that conclude your direct testimony?

A. Yes, it does.

B

DIRECT TESTIMONY OF GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

GENERAL RATES APPLICATION

Q. Please state your name and address for the record.

A. My name is Gary E. Pierson. My business address is 1000 S. Highway 80, Benson, Arizona 85602.

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

A. I am employed by Sierra Southwest Cooperative Services, Inc. ("Sierra Southwest") as the Manager of Financial Services. As Manager of Financial Services, I am responsible for directing and administrating the treasury and cash management functions for Sierra Southwest. In addition, under agreements that Sierra Southwest has with Arizona Electric Power Cooperative, Inc. ("AEPCO") and Southwest Transmission Cooperative, Inc. ("SWTC"), I am responsible for the same functions as well as rate design and implementation for these two cooperatives.

Q. Please briefly summarize your educational and professional background.

A. I graduated in 1974 from Western State College, Gunnison, Colorado, with a Bachelor of Arts Degree specializing in Accounting and Business Administration. In June 1974, I was employed by Colorado-Ute Electric Association, Inc. and worked there for 17 years in various positions in the areas of ratemaking, budgeting, financial forecasting and power requirements studies. In May 1992, I joined AEPCO as a Rates Administrator in the Financial Services Division, where my principal responsibilities and duties included the preparation of rate filings, the design of rate structures and rate analysis studies. In 1993, I was promoted to the position of Manager of Financial Services. I have testified as an expert witness before the Public Utilities Commission of the State of Colorado, the United States Bankruptcy Court in Denver, Colorado and the Arizona Corporation Commission in connection with various proceedings involving rate cases.

Q. What is the purpose of your testimony?

A. I will testify in support of the application for a general rate filing for AEPCO. My testimony is primarily directed to financial schedules A-F which were filed in support of the application. Mr. Goble will testify concerning schedules G and H.

Q. Mr. Pierson, before discussing those schedules, please summarize AEPCO's revenue requirements and rate design requests.

A. AEPCO is asking that the Commission approve a revenue increase of $4.023 million dollars or a 2.41% increase in revenue requirements. That average increase, however, is actually a blend of a 2.83% decrease in the revenues from rates for the all-requirements members and a 5.39% increase in the revenues from rates for the partial-requirements members.

Further, as a result of numerous meetings with the members over the last several years and the development of certain cost causation principles, AEPCO is also proposing modifications to the rate designs that were approved by the Commission in the last rate filing. One of these cost causation principles involves a change in the methodology by which operations and maintenance expense is allocated to the all-requirements members ("ARMs") and the partial-requirements members ("PRMs"). As a result, AEPCO is proposing that the PRMs' O&M rates be changed from a per kW/Month unit rate to a fixed monthly charge. Another of these cost causation principles involves a change in the methodology by which energy-related expenses are allocated to the all-requirements and partial-requirements members. As a result, AEPCO is proposing that the current single energy rate per kWh be subdivided into Base Resources, Other Existing Resources and Additional ARM Resources energy rates for the ARMs and PRMs, as applicable. Also, AEPCO requests that costs recovered through the Purchased Power Fuel Adjustor Clause ("PPFAC") be applied to the same rate categories to be consistent with the proposed energy rate structure.

The following is a summary of present and proposed rate structures:

	Present Rates	Proposed Rates
All-Requirements Members:		
Demand Rate	$14.98/kW Month	$14.05/kW Month
Energy Rates:		
Base Resources		$0.03236/kWh
Other Existing Resources		$0.06730/kWh
Additional ARM Resources		$0.07341/kWh
Energy Rate	$0.02073/kWh	$0.03722/kWh (Average)

Partial-Requirements Members:

MEC:

Fixed Charge	$855,113/Month	$772,376/Month
O&M Charge	$7.26/kW Month	$1,410,263/Month
Energy Rates:		
Base Resources		$0.03216/kWh
Other Existing Resources		$0.06879/kWh
Energy Rate	$0.02073/kWh	$0.03595/kWh (Average)

SSVEC:

Fixed Charge	$757,429/Month	$683,919/Month
O&M Charge	$7.26/kW Month	$1,248,752/Month
Energy Rates:		
Base Resources		$0.03230/kWh
Other Existing Resources		$0.06676/kWh
Energy Rate	$0.02073/kWh	$0.03672/kWh (Average)

In relation to the current energy rate of $0.02073, I would note that the <u>total</u> energy rate charged the members is higher than that energy rate because of the additional PPFAC adjustors which are charged the ARMs and PRMs per kWh of energy use.

Q. Please describe the schedules.

A. They are a multi-page exhibit containing the schedules A-H (the "Schedules") that are described in A.A.C. R14-2-103.B and are divided into the following categories:

Schedule Category	Section Tab
Summary Schedules	A
Rate Base Schedules	B
Test Year Income Statements	C
Cost of Capital Schedules	D
Financial Statements and Statistical Schedules	E
Projections and Forecast Schedules	F
Cost of Service Analysis Schedules	G
Effect of Proposed Tariff Schedules	H

Q. Please describe Section A of the Schedules.

A. Section A contains the rate filing's summary schedules. Schedule A-1 shows the computation of the increase in gross revenue requirements which results from the development of the financial schedules.

As Schedule A-1 shows, the proposed revenue increase of $4.023 million is an increase of 2.41% over the revenues generated by present rates. Current rates produced approximately $529,000 in net margins in the test year ended March 31, 2009, as adjusted. Based upon a test period adjusted rate base of $231.8 million, these proposed revenue requirements generate a rate of return of 6.62%.

Schedule A-2 summarizes results of operations for the 12 months ending March 31, 2007, 2008 and 2009 and the adjusted test year with present rates and with proposed rates. As I mentioned, on an adjusted test year basis, the Test Year Adjusted column shows that AEPCO had a net margin of $529 thousand, a TIER of 1.05 and a DSC of 1.12 in the test year. Under the proposed rates, AEPCO would have a net margin of about $4.5 million, a TIER of 1.42 and a DSC of 1.35 in the test year. Schedule A-3 summarizes AEPCO's capital structure and capitalization ratios for the years ended March 31, 2007 and 2008 as well as the test year and projected year. Schedule A-4 provides data concerning construction expenditures, net plant additions and gross utility plant in service. Schedule A-5 summarizes AEPCO's changes in financial position.

Q. **Please describe Section B of the Schedules.**

A. Section B contains supporting rate base schedules that are used in the AEPCO rate filing. Schedule B-1 summarizes the components of the original cost rate base of $231.8 million, as of March 31, 2009. It includes gross utility plant in service of $399.4 million, accumulated depreciation and amortization of $204.8 million, allowances for working capital of $21.8 million, plant held for future use of $2.6 million and deferred debits of $12.8 million. No adjustments were made to the original cost rate base for the test year (Schedule B-2). Schedules B-3 and B-4, concerning reconstructed cost new less depreciation ("RCND") rate base, have not been completed. As a non-profit cooperative, AEPCO stipulates to the use of its original cost rate base as its fair value rate base.

Schedule B-5, page 1 provides the computation of working capital by components, which sum to total working capital of $21.8 million and the remaining pages show the calculation of the different components. Schedule B-5, page 2, concerning the calculation of cash working capital, has not been completed. Due to the considerable time and expense of preparing a lead/lag study, AEPCO agrees to the use of a zero value for its cash working capital. Nor is AEPCO asking for prepayments to be included in the computation of rate base as shown on Schedule B-5, page 5, because of the position Staff took on this issue in our 2004-2005 rate case.

Q. Please describe Section C of the Schedules.

A. Section C contains adjusted test year income statements and supporting schedules to the income statements. Schedule C-1, pages 1 through 4, provides the actual income statement and the as-adjusted income statement for the test year. Pages 1 and 2 of Schedule C-1 provide per books and reclassified test year income statements for the test year. The first column displays the revenues and expenses of AEPCO during the test year, which is the 12 months ending March 31, 2009. As noted on Schedule C-1, page 2, AEPCO had operating margins of $14.9 million and non-operating margins of $945 thousand that together produced a net margin of $15.8 million. The second column represents reclassification adjustments that are made to the test period which have a zero effect on net margins of AEPCO.

Schedule C-2, pages 1 through 10, provides detail on the reclassification and pro forma adjustments to revenues and expenses. They are as follows:

Reclassification Adjustments – Schedule C-2, Pages 1 and 2:

1. SWTC Revenue Reclassification – This adjustment reclassifies the network service and system control and load dispatching revenues that AEPCO collects from its all-requirements members and then pays to SWTC. These revenues and charges are a pass-through at cost of network services provided by SWTC to AEPCO's all-requirements Class A Members. Therefore, AEPCO has removed them from its cost of service. The net effect of this and the other three reclassifications on net margins discussed below is zero.
2. ACC Gross Operating Revenue Assessment – This adjustment reclassifies the revenues that AEPCO receives from its Class A Members against the expense that it records in administrative and general expenses.
3. Coal Legal Expenses – This adjustment reclassifies certain legal expenses that have been recorded in coal expense to administrative and general expenses to be consistent with the rate treatment afforded these expenses in AEPCO's last rate case.
4. Property Tax Reclassification – This adjustment reclassifies property taxes, which are recorded in various operation and maintenance expense categories according to Rural Utilities Service accounting procedures, to taxes so that these expenses can be shown separately for ratemaking purposes.

Pro Forma Adjustments – Schedule C-2, Pages 3 through 10:

1. Coal Cost Adjustment – AEPCO's long-term coal agreement expired at the end of 2008. After approximately two years of planning in relation to and negotiation of new

agreements, new contracts took effect on January 1, 2009 during the final quarter of the test year. This adjustment annualizes revenues and expenses to reflect the new coal costs, which are expected to average $3.01/MMBtu during 2009. AEPCO has included an additional $8.6 million of revenues expected from contractual sales and $23.6 million of additional expenses associated with these contracts. The effect of this adjustment decreases net margins by $14.9 million.

2. Labor Expense Adjustment – This adjustment annualizes labor expense and associated payroll taxes and benefits to reflect wage increases that occurred during the test period and the wage increase that takes effect on the date of this filing, October 1, 2009. In addition, this adjustment reflects the increase in contributions that AEPCO is obligated to pay to the National Rural Electric Cooperative Association for participation in its Retirement and Security Program, which is AEPCO's pension plan for employees. The effect of this adjustment decreases net margins by $1.5 million.

3. Salt River Project Contract Expiration Adjustment – Since 1990, AEPCO has been selling firm capacity of initially 50 MW and then 100 MW to the Salt River Project ("SRP"). This contract, which was approved by the Commission in Decision No. 56101 dated August 31, 1988, expires on December 31, 2010. This adjustment reflects the test year effect of the expiration of that 100 MW sales contract. Hourly generation and purchased power dispatches in connection with this contract have been reviewed to reflect decreased generation and purchased power expenses that would have occurred if this contract had not been in effect during the test year. In addition, AEPCO has also eliminated the associated charges that were paid to SWTC to wheel the power associated with this contract. The effect of these adjustments decreases net margins by

$13.2 million. However, as I discuss shortly, other adjustments have been made to increase AEPCO revenues as a result of increased sales (with related expenses) which are expected to occur as a result of the availability of this 100 MW.

4. City of Mesa Contract Expiration Adjustment – This adjustment annualizes the test year effect of the expiration of the 15 MW sales contract to the City of Mesa ("Mesa") that occurred last year on December 31, 2008. This agreement was approved by the Commission on May 1, 1991 in Decision No. 57343. AEPCO has reviewed the hourly generation and purchased power dispatched in connection with this contract as to decreased generation and purchased power expenses that would have occurred if this contract had not been in effect during the test year. In addition, AEPCO has eliminated the associated charges that were paid to SWTC to wheel the power associated with this contract. This adjustment decreases net margins by $2.3 million. However, as with the SRP contract, I discuss associated increased revenue adjustments below.

5. Public Service Company of New Mexico Contract Expiration Adjustment – This adjustment annualizes the test year effect of the expiration of the purchased power contract with Public Service Company of New Mexico ("PNM") that occurred on December 31, 2008. AEPCO has reviewed the hourly generation and purchased power that was dispatched in connection with this contract as to the decreased purchased power expenses that would have occurred if this contract had not been in effect during the test year. This adjustment increases net margins by $4.7 million.

6. MEC Additional Sales Adjustment – This adjustment reflects the effects of the additional capacity allocated to Mohave Electric Cooperative, Inc. ("MEC") under the terms of its partial-requirements agreement as a result of the expirations of the SRP,

Mesa and PNM contracts. AEPCO has reviewed the hourly generation and purchased power that was dispatched in connection with the MEC partial-requirements contract and made assumptions as to increased sales, additional fuel costs associated with such sales, resource transfers to other parties and displacement of other resources that would have occurred if this additional capacity had been available to MEC during the test year. The effect of this adjustment results in an increase in net margins of $5.3 million.

7. SSVEC Additional Sales Adjustment – Similarly, this adjustment reflects the effects of the additional capacity allocated to and additional impacts as described above in relation to Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") under the terms of its partial-requirements agreement as a result of the expirations of the SRP, Mesa and PNM contracts. This adjustment increases net margins by $3.9 million.

8. All-Requirements Members Coal and Purchased Power Adjustment – Similarly, this adjustment annualizes the effects of the changes in resources that would have occurred for the all-requirements members as a result of the expirations of the SRP, Mesa and PNM contracts. Based on the same review and analysis process described above in relation to MEC, the effect of this adjustment is to increase net margins by $6.5 million.

9. Maintenance Outage Adjustment – This adjustment to test period costs amortizes minor outage expenses over a two-year period and major outage expenses over a six-year period. This adjustment results in a decrease in net margins of $2.1 million.

10. SAP Software Amortization – This adjustment annualizes the amortization of the expenses associated with the installation of the Systems Applications Products ("SAP") software at AEPCO over a seven-year period which started during the test year. This adjustment decreases net margins by $825 thousand.

11. Mercury Control Adjustment – This adjustment reflects the chemical costs which will be incurred as a result of the 50% reduction in mercury emissions requirement, starting in the year 2011, pursuant to the consent decree dated January 30, 2009 between AEPCO and the Arizona Department of Environmental Quality. This adjustment decreases net margins by $2.8 million.

12. Southpoint PPA Capacity Adjustment – This adjustment reduces the Southpoint contract capacity from 30 MW to 25 MW to reflect the effect of the expirations of the SRP, Mesa and PNM contracts. This adjustment increases net margins by $232 thousand.

13. Rate Case Expense Amortization – This adjustment assumes legal and rate consultant costs associated with the rate application of $480,000 and amortizes those expenses over a three-year period. The effect of this adjustment results in a decrease in net margins of $160 thousand.

14. Interest Expense Adjustment – This adjustment annualizes interest expense based upon debt balances and interest rates at the end of the test year, which increases interest expense by $231 thousand. Net margins are decreased by the same amount. In addition, AEPCO has adjusted the principal payments for the test period to reflect extended maturity dates on certain FFB notes that was accomplished on December 31, 2008. This reduced principal payments by $7.3 million.

15. Fuel and Purchased Power Synchronization – This adjustment increases revenues to synchronize the Fuel and Purchased Power Adjustor Clause revenues with the pro forma fuel and purchased power energy costs discussed in previous adjustments. This increases margins by $2.0 million.

As indicated on page 10 of Schedule C-2, the total of these pro forma adjustments to expenses and revenues resulted in a decrease in net margins of $15.3 million.

Finally, Schedule C-3 states the computation of the gross revenue conversion factor.

Q. Please describe Section D of the Schedules.

A. The D Schedules contain information on AEPCO's cost of capital for the 12 months ended March 31, 2007, 2008 and 2009 and projected 12 months ended March 31, 2010. Schedule D-1 sets forth the computed cost of capital as of March 31, 2009 for the actual and projected year ended March 31, 2010. Invested debt capital amounted to $193.9 million with a composite cost rate of 5.92%. Schedule D-2 shows long-term and short-term debt balances by lender that comprise the total; the interest rates associated with the debt balances; and the computation of the composite cost rate for three actual years and the projected year. Schedules D-3 and D-4 on preferred stock and common equity are not applicable to AEPCO because it is a member-owned, non-profit cooperative.

Q. Please describe Section E of the Schedules.

A. Section E contains financial statements and statistical schedules for the 12 months ending March 31, 2007, 2008 and 2009. Schedule E-1 provides comparative balance sheets and Schedule E-2 shows comparative income statements. Schedule E-3 provides a comparative statement of changes in financial position and Schedule E-4 reflects changes in equity. Schedule E-5 provides detail of utility plant additions during the test year and balances as of March 31, 2008 and 2009. Schedule E-6 is not applicable to AEPCO. Schedule E-7 provides AEPCO operating statistics, while Schedule E-8 lists taxes charged to operations. Attached to my testimony as Exhibit GEP-1 are the Consolidated Financial Statements which include the Independent Auditor's Report to the AEPCO Board of Directors dated May 13, 2009. It contains the information that is referenced in Schedule E-9.

Q. Finally, please describe Section F of the Schedules.

A. Section F contains various projections and forecast schedules. Schedule F-4 discusses certain assumptions used in developing the projections contained in the previous F schedules.

Q. Concerning the PPFAC, does AEPCO have recommendations regarding it?

A. Yes. AEPCO requests that the Commission approve continuation of the adjustor mechanism authorized in the 2005 rate decision with certain modifications. As a result of discussions with the Class A Members, AEPCO is proposing energy rates that are based upon three separate cost pools for MEC, SSVEC and the all-requirements members, as applicable. Mr. Goble discusses this concept in greater detail in his testimony. Consistent with these separate energy rates, separate PPFAC power cost bases will be established for the Base Resources pool and the Other Existing Resources pool for MEC and SSVEC. For all-requirements members, separate PPFAC bases will be established for a Base Resources pool, the Other Existing Resources pool and the Additional ARM Resources pool.

Q. Please discuss any other PPFAC issues.

A. We will work with Staff to refine details, but basically the same monthly reporting and semi-annual filing/adjustment procedures would be followed that have been in place for the past several years. The adjustor bases shown on Exhibit GLG-2 are the recommended clause bases. Finally, AEPCO also requests that any carbon taxes, CO2 Cap and Trade Allowances or similar levies, if any, mandated in the future be allowed to be recovered through the PPFAC.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit GEP-1

Exhibit GEP-1

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

INDEPENDENT AUDITOR'S REPORT AND FINANCIAL STATEMENTS

DECEMBER 31, 2008 AND 2007

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INDEPENDENT AUDITOR'S REPORT

The Board of Directors
Arizona Electric Power Cooperative, Inc.

We have audited the accompanying balance sheets of Arizona Electric Power Cooperative, Inc. (the Cooperative) as of December 31, 2008 and 2007 and the related statements of revenues and expenses and unallocated accumulated margins and cash flows for the years then ended. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards,* issued by the Comptroller General of the United States. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Cooperative as of December 31, 2008 and 2007 and the results of its operations and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards,* we have also issued a report dated May 13, 2009 on our consideration of the Cooperative's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in conjunction with this report in considering the results of our audit.

Moss Adams LLP

Portland, Oregon
May 13, 2009

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
BALANCE SHEETS

ASSETS

	DECEMBER 31, 2008	DECEMBER 31, 2007
UTILITY PLANT		
Plant in service	$ 402,042,682	$ 393,889,048
Construction work in progress	20,108,331	3,128,219
Total utility plant	422,151,013	397,017,267
Less accumulated depreciation	204,728,929	198,830,152
Utility plant, net	217,422,084	198,187,115
INVESTMENTS		
Restricted held to maturity	9,862,193	6,313,693
Unrestricted	7,166,123	7,149,486
Total investments	17,028,316	13,463,179
CURRENT ASSETS		
Cash and cash equivalents		
General unrestricted	1,138,577	6,426,466
Restricted	3,871,394	3,776,700
Accounts receivable	20,661,593	21,611,126
Accumulated under-recovered fuel and purchased power costs	7,238,080	5,593,468
Inventories, at average cost		
Coal and natural gas	19,099,253	8,520,622
Materials and supplies	6,919,946	6,307,932
Prepayments and other current assets	978,377	1,166,881
Notes receivable	58,739	86,873
Total current assets	59,965,959	53,490,068
DEFERRED DEBITS	9,464,344	6,199,874
Total assets	$ 303,880,703	$ 271,340,236

See accompanying notes.

MEMBERSHIP CAPITAL AND LIABILITIES

	DECEMBER 31, 2008	DECEMBER 31, 2007
MEMBERSHIP CAPITAL		
Membership fees	$ 430	$ 430
Patronage capital	57,201,869	25,454,747
Unallocated accumulated margins	17,355,770	31,747,122
Total membership capital	74,558,069	57,202,299
LONG-TERM DEBT		
Federal Financing Bank	109,018,862	110,748,768
Cooperative Utility Trust	19,351,712	21,116,169
Solid Waste Disposal Revenue Bonds	14,765,608	15,372,414
Cooperative Finance Corporation	29,300,244	932,281
Rural Utilities Service	107,908	674,423
Captial lease obligation	4,651,289	2,336,012
Total long-term debt	177,195,623	151,180,067
CURRENT LIABILITIES		
Member advances and other investments	18,541,623	17,760,555
Current maturities of capital lease obligation	1,260,950	448,045
Current maturities of long-term debt	6,645,314	16,457,993
Accounts payable	13,307,282	7,230,981
Accrued property and business taxes	2,229,488	2,212,431
Accrued interest	725,295	965,725
Line of credit - Cooperative Finance Corporation	5,400,000	13,943,050
Other	1,097,548	897,665
Total current liabilities	49,207,500	59,916,445
ASSET RETIREMENT OBLIGATIONS	1,654,712	1,439,346
DEFERRED CREDITS	1,264,799	1,602,079
Total membership capital and liabilities	$ 303,880,703	$ 271,340,236

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF REVENUES AND EXPENSES AND UNALLOCATED ACCUMULATED MARGINS

	YEAR ENDED DECEMBER 31, 2008	YEAR ENDED DECEMBER 31, 2007
OPERATING REVENUES		
Sales of electric energy		
Members		
Class A - Firm	$ 123,646,648	$ 138,437,318
Class A - Non Firm	-	177,397
Class B	42,938,769	6,675,767
Class C	-	33,716,073
Class D	1,593,208	2,717,522
Under-recovery of fuel and purchase power costs	38,638,375	24,672,520
Nonmembers	8,402,255	5,400,208
Other, net	728,133	981,112
Total operating revenues	215,947,388	212,777,917
OPERATING EXPENSES		
Power generation		
Fuel	69,854,969	68,096,074
Operation	10,581,716	10,023,850
Maintenance	15,322,190	16,244,572
Purchased power and interchange	52,328,850	41,230,238
Administration and general	10,843,391	9,674,147
Depreciation, amortization and accretion	8,054,263	7,900,636
Transmission	18,526,791	25,955,050
Property and other taxes	2,934,495	3,340,972
Reduction in asset retirement obligation estimate	-	(1,210,453)
Total operating expenses	188,446,665	181,255,086
OPERATING MARGIN	27,500,723	31,522,831
Interest and interest related expenses, net	(11,393,082)	(12,978,824)
Other income, net	1,248,129	2,005,528
NET MARGIN	**17,355,770**	**20,549,535**
UNALLOCATED ACCUMULATED MARGINS, beginning of year	31,747,122	18,849,096
PATRONAGE CAPITAL ALLOCATION	(31,747,122)	(7,651,509)
UNALLOCATED ACCUMULATED MARGINS, end of year	$ 17,355,770	$ 31,747,122

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES		
Net margin	$ 17,355,770	$ 20,549,535
Adjustments to reconcile net margin to net cash from operating activities		
Depreciation and amortization	8,054,263	7,811,346
Amortization of deferred charges	77,989	84,480
Amortization of other deferred credits	(337,280)	(337,280)
Patronage capital allocations	(101,528)	(179,791)
Accretion of asset retirement obligations	95,185	89,290
Settlement of asset retirement obligations	-	(1,210,453)
Changes in assets and liabilities		
Restricted cash and cash equivalents	(94,694)	(496,618)
Accounts and notes receivable	977,667	(4,093,929)
Accumulated under-recovered fuel and purchased power costs	(1,644,612)	5,474,080
Inventories	(11,190,645)	(2,460,815)
Prepayments and other current assets	188,504	(185,721)
Deferred debits	(3,342,459)	1,111,405
Accounts payable	6,076,301	(2,254,135)
Accrued interest	(240,430)	(2,223,937)
Accrued overhaul	-	4,353,314
Accrued property and business taxes and other	216,940	499,836
Net cash from operating activities	16,090,971	26,530,607
CASH FLOWS FROM INVESTING ACTIVITIES		
Construction expenditures, net	(23,919,051)	(4,865,794)
Purchases and redemptions of investments, net	(3,463,609)	2,246,457
Net cash from investing activities	(27,382,660)	(2,619,337)
CASH FLOWS FROM FINANCING ACTIVITIES		
Membership fees	-	100
Member advances and other investments, net	781,068	7,031,039
Proceeds from long-term debt	30,386,500	-
Line of credit activity, net	(8,543,050)	(5,056,950)
Payments on long-term debt and capital lease obligation	(16,620,718)	(27,637,469)
Net cash from financing activities	6,003,800	(25,663,280)
CHANGE IN CASH AND CASH EQUIVALENTS	(5,287,889)	(1,752,010)
CASH AND CASH EQUIVALENTS, beginning of year	6,426,466	8,178,476
CASH AND CASH EQUIVALENTS, end of year	$ 1,138,577	$ 6,426,466

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31, 2008	2007
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid for interest, net of amount capitalized	$ 11,555,523	$ 15,118,281
Noncash investing activities		
Liabilities incurred for asset retirement obligations	$ 120,181	$ 112,742
Assets acquired under a capital lease	$ 3,250,000	$ 502,173

See accompanying notes.

Note 1 - Organization

Arizona Electric Power Cooperative, Inc. (the Cooperative) is a member owned, nonprofit Arizona rural electric generation cooperative organized in 1961 to provide wholesale electric power to its member distribution cooperatives, municipalities and other customers.

Membership of the Cooperative is restricted to electric utilities. The Cooperative has four classes of members. Class A members consist of four distribution cooperatives with all requirements contracts and two distribution cooperatives with partial requirements contracts. Class B members consist of two electric utilities with partial requirements contracts. As of December 31, 2008 there were no Class C members. In 2007, a Class D member was added, representing electric utilities other than Class A, B, or C with a written agreement for power and/or energy and/or substantial service, represented jointly by one director. Class A, Class B, Class C and Class D members are collectively referred to herein as members.

Note 2 - Summary of Significant Accounting Policies

System of accounts - The Cooperative maintains its accounts in accordance with policies and procedures as prescribed by the Rural Utilities Service (RUS) in conformity with the Uniform System of Accounts. The Cooperative's accounting policies conform to accounting principles generally accepted in the United States of America as applied in the case of regulated public utilities and are in accordance with the accounting requirements and rate-making practices of the RUS and the Arizona Corporation Commission (ACC), the regulatory authorities having jurisdiction.

Accounting for the effects of regulation - The Cooperative prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standard (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. SFAS No. 71 requires a cost-based, regulated enterprise to recognize revenues and expenses in the time periods when the revenues and expenses are included in rates. This may result in regulatory assets and liabilities until such time that the related revenues and expenses are included in rates.

Utility plant - Utility plant, consisting primarily of coal and natural gas electric generation facilities, is stated at historical cost and includes the costs of outside contractors, direct labor and materials, allocable overhead and interest charged during construction.

In accordance with the Uniform System of Accounts, the Cooperative capitalizes the interest costs associated with the borrowing of funds used to finance construction work in progress (CWIP). Interest income from construction funds held in trust, if any, is credited to CWIP. Interest costs capitalized on construction projects was approximately $180,000 and $156,000 for 2008 and 2007, respectively.

Note 2 - Summary of Significant Accounting Policies (Continued)

Depreciation is computed on the straight-line basis over estimated useful lives of depreciable property in accordance with rates prescribed by RUS, averaging 2.0% in 2008 and 2007. Minor replacements and repairs are charged to expense as incurred. Retirements of utility plant, together with the cost of removal, less salvage, are charged to accumulated depreciation.

The Cooperative assesses its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the fair value is less than the carrying amount of the asset, a loss is recognized for the difference. The Cooperative has not recorded any losses resulting from impairment of its long-lived assets.

Asset retirement obligations - 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 accretion of the ARO liability classified as an operating expense.

Investments - The Cooperative accounts for its investments in accordance with SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities. SFAS No. 115 provides that the Cooperative classify investments in securities as either trading securities, held-to-maturity securities, or available-for-sale securities. At December 31, 2008 and 2007, all investment balances were classified as held-to-maturity securities and are therefore recorded at amortized cost (See Note 3).

A decline in the market value of held-to-maturity securities below cost that is deemed to be other-than-temporary results in a reduction in carrying amount to fair value. The impairment is charged to margins and a new cost basis for the security is established. To determine whether an impairment is other-than-temporary, the Cooperative considers whether it has the ability and intent to hold the investment until a market price recovery and considers whether evidence indicating the cost of the investment is recoverable outweighs evidence to the contrary. Evidence considered in this assessment includes the reasons for the impairment, the severity and duration of the impairment, changes in value subsequent to year end and forecasted performance of the investee. Management does not believe the investments are impaired as of December 31, 2008.

Cash equivalents - The Cooperative considers all investments with an original maturity of 90 days or less to be cash equivalents. The Cooperative maintains its cash in bank accounts, which, at times, exceed federally insured limits and has not experienced any losses in such accounts.

Receivables - Receivables are recorded when invoices are issued and are written off when they are determined to be uncollectible. The allowance for doubtful accounts is estimated based on historical losses, review of specific problem accounts, the existing economic conditions in the industry and the financial stability of customers. Generally, accounts receivable are considered past due after 30 days. No allowance was deemed necessary at December 31, 2008 and 2007.

Note 2 - Summary of Significant Accounting Policies (Continued)

Inventories - Inventories, consisting of coal, natural gas and materials and supplies, are carried at average cost.

Deferred debits and credits - Deferred debits and credits are recorded at cost and either: (1) amortized over their expected period of benefit or alternate period of time as may be mandated by ACC order, if different, or (2) eliminated upon determination of their ultimate disposition.

Unamortized debt costs - Costs incurred for the issuance or repricing of long-term debt are deferred and amortized over the life of the related debt (See Note 7).

Overhaul costs - The Cooperative accounts for major and minor overhauls using the deferral method. Accordingly, incurred overhaul costs are deferred and amortized over the overhaul benefit period, generally two years for minor overhauls and six years for major overhauls. The frequency of overhauls is based on the operating characteristics and operating profiles of each generating unit. See Note 7.

Revenues, purchased power and fuel costs - Revenues are recognized as electric power and other energy service products are delivered at rates approved by the ACC. Purchased power and fuel costs are charged to expense as incurred.

In its April 15, 2005 rate order, the ACC approved a fuel and purchased power cost adjustor (the adjustor) for the Cooperative. This adjustor enables the Cooperative to accumulate its over and under collection of fuel and purchased power costs and subsequently, as approved by the ACC, refund or collect from its members the amount of over and under collection of fuel and purchased power costs. Such amounts are recorded as revenue in the period the costs are incurred.

Fair value of financial instruments - Many of the Cooperative's financial instruments lack an available trading market as characterized by a willing buyer and willing seller engaged in an exchange transaction. The Cooperative's general practice and intent is to hold its financial instruments to maturity and not to engage in trading or sales activities. As a result, significant estimations using the best available information and present value calculations are used by the Cooperative for purpose of disclosure. For current financial instruments, the carrying amounts approximate fair value.

Use of estimates - The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

Reclassifications - Certain reclassifications were made to the prior year financial statements to conform to the current year presentation. Such reclassifications had no impact on previously reported net margin.

Note 3 - Investments

Investments at December 31 consist of the following:

	2008		
	Amortized Cost	Unrealized Gain	Fair Value
Restricted - municipal bonds	$ 2,807,111	$ 125,986	$ 2,933,097
Restricted - term certificates	7,055,082	-	7,055,082
Investment in associated organizations	3,979,809	-	3,979,809
Patronage capital	3,186,314	-	3,186,314
Total	$ 17,028,316	$ 125,986	$ 17,154,302

	2007		
	Amortized Cost	Unrealized Gain	Fair Value
Restricted - municipal bonds	$ 2,807,111	$ 142,510	$ 2,949,621
Restricted - term certificates	3,506,582	-	3,506,582
Investment in associated organizations	3,981,212	-	3,981,212
Patronage capital	3,168,274	-	3,168,274
Total	$ 13,463,179	$ 142,510	$ 13,605,689

Contractual maturities of restricted investments at December 31 are as follows:

	2008		2007	
	Cost	Fair Value	Cost	Fair Value
Due from one year to five years	$ 3,617,472	$ 3,617,565	$ -	$ -
Due from six years to ten years	14,954	15,161	15,065	15,065
Due after ten years	6,229,767	6,355,453	6,298,628	6,441,138

Municipal bonds - As a condition of National Rural Utilities Cooperative Finance Corporation's (CFC) guarantee of the Solid Waste Disposal Revenue Bonds (See Note 8), the Cooperative purchased a non-interest bearing Debt Service Reserve Certificate (the certificate) maturing in 2024 upon final payment of the debt. The proceeds of the certificate are held by CFC in a Debt Service Reserve Fund (DSRF). One of the underlying investments, totaling approximately $2,762,000 and maturing in 2022, has a call feature exercisable by the issuer beginning in 2008.

Note 3 - Investments (Continued)

Term certificates - The Cooperative is a member of CFC, a not-for-profit cooperative financing institution. As a condition of membership, the Cooperative purchased Subscription Capital Term Certificates (SCTCs). The SCTCs, totaling $2,759,517 at December 31, 2008 and 2007, bear interest at 5% per annum and have maturity dates ranging from 2070 to 2080.

As a condition of the Solid Waste Disposal Revenue Bonds (See Note 8), which are guaranteed by CFC, the Cooperative purchased a Subordinated Term Certificate (STC). The STC, totaling $708,000 and $732,000 at December 31, 2008 and 2007, respectively, bears interest at 7.6% per annum and matures in full in 2024 upon final payment of the related debt.

As a condition of the long-term debt due CFC (See Note 8), the Cooperative purchased Zero Term Certificates (ZTCs). One of the ZTCs, totaling $15,065 as of December 31, 2008 and 2007, is non-interest bearing and matures in 2013. New ZTCs totaling $3,572,500 purchased in 2008 bear interest at 4.36% per annum and mature in 2013.

The SCTCs, STC and ZTCs are unrated, uncollateralized debt securities of CFC.

Investment in associated organizations - The Cooperative is a Class B member of Sierra Southwest Cooperative Services, Inc. (Sierra). The Cooperative's investment in Sierra is carried at cost (See Note 17).

In December 2006, the Cooperative became an equity member of Alliance for Cooperative Energy Services Power Marketing LLC (ACES). The Cooperative's investment in ACES is accounted for under the cost method of accounting.

Patronage capital - Patronage capital represents capital credit allocation of margins due to the Cooperative. Such amounts are returned to the Cooperative in accordance with the associated organizations bylaws and/or at their discretion. Of this balance, $2.7 million represents patronage allocations from Southwest Transmission Cooperative (See Note 17).

Municipal bonds are valued based on quoted market prices for those or similar investments. The fair value of term certificates, investment in associated organizations and patronage capital is not readily determinable; therefore, they are recorded at cost.

Note 4 - Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents at December 31 consist of the following:

	2008	2007
California power sales collateral security (Note 11)	$ 2,500,000	$ 2,500,000
Rural economic development revolving loan program (Note 6)	421,109	392,976
Other deposits on account	950,285	883,724
Total restricted cash and cash equivalents	$ 3,871,394	$ 3,776,700

Note 5 - Accounts Receivable

Accounts receivable at December 31 consist of the following:

	2008	2007
Member energy sales	$ 17,717,117	$ 19,765,764
Due from related party	716,445	1,167,014
Nonmember energy sales	1,474,094	625,418
Other	753,937	52,930
Total accounts receivable	$ 20,661,593	$ 21,611,126

Member energy sales - Member energy sales consist of sales to Members under their wholesale power sales contracts (See Note 11 - *Member Wholesale Power Sales Contracts*) and generally are not collateralized.

Nonmember energy sales - Nonmember energy sales consist of nonfirm sales to unrelated electric utilities and are generally not collateralized.

Note 6 - Notes Receivable

In 1998, the Cooperative was awarded a $400,000 Rural Utilities Service Rural Economic Development Grant. In accordance with grant guidelines, the initial loans made to qualifying recipients carry a zero interest rate and are repaid over a ten-year period. Loan repayments are required to be used to establish a revolving loan fund, which in turn, is used for providing loans to foster rural economic development. Loans made from repayments of the initial loans may carry an interest rate. As of December 31, 2008 and 2007, the Cooperative has $421,000 and $393,000, respectively, of cash and cash equivalents restricted for use in this program (See Note 4).

Note 7 - Deferred Debits

Deferred debits at December 31 consist of the following:

	2008	2007
Deferred overhaul costs	$ 7,719,209	$ 5,486,420
Unamortized debt costs	329,362	389,206
Preliminary survey and investigation and other deferred debits	1,240,375	130,705
Redemption premium (See Note 8)	175,398	193,543
Total deferred debits	$ 9,464,344	$ 6,199,874

Note 8 - Long-Term Debt

Federal Financing Bank (FFB) - Long-term debt due FFB is payable at interest rates based on long-term obligations of the United States Government as determined on the date of advance. Interest rates on existing FFB debt range from 4.2% to 9.1% for December 31, 2008 and 2007. Quarterly principal and interest installments on these obligations extend through 2034. The obligations are guaranteed by RUS. The Cooperative may prepay all outstanding notes by paying the principal amount plus the lesser of: 1) the difference between the outstanding principal balance of the loan being refinanced and the present value of the loan discounted at a rate equal to the then current cost of funds to the Department of the Treasury for obligations of comparable maturity; 2) 100% of the amount of interest for one year on the outstanding principal balance of the loan being refinanced multiplied by the ratio of a) number of quarterly payment dates remaining to maturity bears to b) number or quarterly payment dates between year 13 of the loan and the maturity date; or 3) present value of 100% of the amount of interest for one year on the outstanding principal balance of the loan.

Cooperative Utility Trust - The Cooperative issued a note, underlying a Certificate of Beneficial Interests (the Certificate), to a Cooperative Utility Trust. Principal payments on the note are due annually through 2018 and guaranteed by RUS. The interest rate on the note is 7.7%, paid semiannually. The note may be prepaid any time after September 1, 2006 at 103.5% of the outstanding principal amount of the note on the date of prepayment, declining one half percent per year to 100% beginning September 1, 2013 and thereafter.

Note 8 - Long-Term Debt (Continued)

Solid Waste Disposal Revenue Bonds - Principal on these bonds is due in annual installments through 2024. Interest rates on the bonds are variable and subject to revision semiannually. The interest rate in effect at December 31, 2008 and 2007 was 2.35% and 3.75%, respectively. Interest is paid semiannually. These bonds are guaranteed by CFC and are not subject to optional redemption prior to maturity.

Rural Utilities Service - Long-term debt due RUS consists of notes at interest rates of 2% and 5% for 2008 and 2007. Quarterly principal and interest payments on these obligations extend through 2010. The Cooperative may prepay the notes at an amount not less than the outstanding principal balance of the loan. The discount rate is the rate specified in the Treasury Constant Maturities section of the weekly publication of the Federal Reserve Statistical Release.

RUS established a Cushion of Credit Payment Program, whereby borrowers may make advance payments on their RUS and FFB notes (Notes). These advance payments earn interest at the rate of 5.0% per annum. The advance payments, plus any accrued interest, can only be used for the payment of principal and interest on the Notes. The Cooperative's participation in the Cushion of Credit Payment Program totaled approximately $26,000 and $5,000 at December 31, 2008 and 2007, respectively, and is recorded as a reduction of RUS long-term debt on the balance sheets.

Cooperative Finance Corporation - Long-term debt due CFC is payable at a variable interest rate that is established monthly and effective on the first day of each month. The interest rate in effect at December 31, 2008 and 2007 was 5.40% and 6.55%, respectively. Quarterly principal and interest payments on this obligation extend through 2013. This obligation is guaranteed by RUS. The variable interest rate on the debt is convertible to a fixed rate. The fixed rate would be equal to the rate of interest offered by CFC at the time of the conversion request. The Cooperative may prepay fixed rate notes in whole or in part, subject to a prepayment premium prescribed by CFC.

Maturities of long-term debt - Maturities of long-term debt for the next five years and thereafter are as follows:

2009	$ 6,645,314
2010	6,606,097
2011	7,104,889
2012	8,106,865
2013	37,302,461
Thereafter	113,424,022
	$ 179,189,648

Note 8 - Long-Term Debt (Continued)

Under covenants of the Consolidated Mortgage and Security Agreement (Mortgage), dated June 14, 1989, by and among the Cooperative, CFC and the United States of America acting through RUS, and RUS general and preloan policies and procedures, the Cooperative must, among other things, obtain approvals from both RUS and CFC for certain transactions and contracts and design its rates with a view to maintaining, on an annual basis, an average times interest earned ratio of 1.05 and debt service coverage ratio of 1.0 calculated retrospectively using the highest ratios from two of the three most recent years. Management believes these financial covenants have been achieved as of December 31, 2008.

Long-term debt is collateralized by the pledge of all assets through the Mortgage.

The fair value of the Cooperative's long-term debt is estimated by discounting the future cash flows required under the terms of each respective debt agreement by the currently quoted or offered rates for the same or similar issues of debt with similar maturities. The principal amounts of variable rate debt are considered reasonable estimates of their fair value. The fair value of debt at December 31, 2008 and 2007 was $188,961,909 and $177,907,656, respectively.

Components of interest expense at December 31 consist of the following:

	2008	2007
Total interest costs and related amortization	$ 11,572,860	$ 13,135,195
Interest capitalized	(179,778)	(156,371)
Total interest expense	$ 11,393,082	$ 12,978,824

Note 9 - Member Advances and Other Investments

Member investment program - The Cooperative offers all Members the ability to invest funds with the Cooperative on a short-term basis for periods of up to nine months. The Cooperative had recorded liabilities for notes of $12,134,537 and $10,756,899 at December 31, 2008 and 2007, respectively. The interest rate on these notes averaged 2.4% and 5.2% in 2008 and 2007, respectively. Interest expense on these notes was approximately $281,000 and $441,000 for the years ended December 31, 2008 and 2007, respectively.

Prepaid power program - The Cooperative also offers a program for all Members whereby the Members may make interest-bearing prepayments of their monthly power billings. The prepayment and accrued interest are applied to the Members' power billings on the date such billings become due. The Cooperative recorded liabilities for prepayments of $4,127,159 and $4,539,855 at December 31, 2008 and 2007, respectively. The interest rate on these prepayments averaged 2.5% and 5.3% in 2008 and 2007, respectively. Interest expense on these prepayments was approximately $74,000 and $217,000 for the years ended December 31, 2008 and 2007, respectively.

Environmental Portfolio Standard Plan (EPS Plan) - The Arizona Corporation Commission established the Environmental Portfolio Standard requirements in 2005 to require Arizona utility companies to generate a percentage of their power through green or renewable resources. The Cooperative Class A Arizona Members collect the funds through their monthly billings and the Cooperative manages these funds on behalf of these Members. Once the Cooperative incurs expenditures related to an approved renewable resource project, Member balances are reduced by their proportionate shares of the expenditures. The balance of these funds at December 31, 2008 and 2007 was $1,582,840 and $1,927,772, respectively.

Note 10 - Deferred Credits

Customer advance payments - In 1987, the Cooperative entered into a long-term power sale agreement with a nonmember customer for an initial term of 25 years. The customer made advance payments for demand charges under this agreement totaling $8,432,000. The advance payments are being amortized as revenue on a straight-line basis over the term of the agreement.

Note 11 - Commitments and Contingencies

Class A Member Power Sales Contracts - ***Wholesale Power Sales Contracts*** **-** The Cooperative holds all requirements wholesale power sales contracts with four of its six Class A Member cooperatives pursuant to which each Class A Member agrees to purchase from the Cooperative all of its electric power requirements. These all requirements power contracts expire December 31, 2035 and will remain in effect thereafter until terminated by either party upon six months notice. Management believes the Cooperative will be able to fulfill its requirements on these long-term contracts. The Cooperative has one Class A all requirements Member whose conversion to a partial requirements contract arrangement was approved by the Arizona Corporation Commission in December 2007 and was effective January 1, 2008.

Class A Member Power Sales Contracts - ***Partial Requirements Wholesale Power Agreements*** - The Cooperative holds partial requirements wholesale power sales contracts, expiring December 31, 2035, with two of its Class A Member cooperatives pursuant to which the Class A Members have agreed to purchase from the Cooperative electric energy and capacity up to the Member's allocated capacity percentage in the Cooperative's total resources existing at the time of execution of the contract. The Cooperative has one Class A Member whose conversion to a partial requirements contract arrangement was approved by the Arizona Corporation Commission in December 2007 and was effective January 1, 2008.

Class B and Class C Member Power Sales Contracts - The power sales contract with the Cooperative's Class B Member, for the sale of 15 MW of capacity, expired on December 31, 2008. The power sales contract with the Cooperative's Class B Member, for the sale of 100 MW of capacity, expires on December 31, 2010. There are no Class C Member contracts at this time.

Class D Member Power Sales Contract - Class D membership requires the Member to enter into a service contract for scheduling and trading services for a minimum term of 2 years. The service contract with the Cooperative's Class D Member is renewed annually until terminated by either party upon a six month written notice.

Nonmember Power Sales Agreement - Nonmember power sales agreement consists of the following:

- 8 MW agreement expiring on December 31, 2012.

Note 11 - Commitments and Contingencies (Continued)

Wholesale Power Purchase Contracts - The Cooperative's current power supply includes the following purchase power agreements:

- Hydroelectric power purchases from Western Area Power Administration (Western), a federal power marketing agency. Under the terms of its Salt Lake City Integrated Project (formerly Colorado River Storage Project) contract, which expires September 30, 2024, the Cooperative can receive up to 2.4 MW during October through March and up to 12.5 MW during April through September for service to its Class A Members. Additionally, under the terms of a contract with the Parker Davis Project, which expires September 30, 2028, the Cooperative receives 18.4 MW during October through February and 23.8 MW during March through September.
- Power purchase agreement with the Public Service Company of New Mexico, expired on December 31, 2008, to purchase capacity of 15 MW.
- Power purchase agreement with South Point Energy Center to purchase capacity in Peak Hours ranging from 30 MW to 55 MW during the months of May through October for the term of the agreement which began on May 1, 2008 and expires October 31, 2014.
- Power purchase agreement with Griffith Energy, LLC, a Dynegy subsidiary, to purchase capacity in Peak Hours of 25 MW during the months of May through October for the term of the agreement which began on May 1, 2008 and expires October 31, 2014.
- Power purchase agreement with Powerex Corp to purchase energy in Peak Hours of 25 MW during the months of June, July and August 2007 and 2008, and 35 MW during the same months of 2009 and 2010.

Network Service Agreement (Class A) - The Cooperative holds an agreement with Southwest Transmission Cooperative, Inc. (SWTC) for network integration transmission service for delivery of its power sales to the Cooperative's all requirements Class A Members. This agreement remains in effect as long as any existing wholesale power contract between the Cooperative and any of the all requirements Class A members remains in effect (See Note 17).

Bundled Transmission Service Agreements - The Cooperative holds agreements with SWTC for point-to-point transmission for the Cooperative's bundled power sales agreements. These agreements provide for reserved transmission capacity ranging from 8 MW to 100 MW. They remain in effect as determined by each power sale agreement (See Note 17).

Wholesale Transmission Contracts - The Cooperative holds separate agreements by which it takes transmission services from other entities ranging from 35 MW to 50 MW, which will remain in effect in accordance with each respective service agreement. The Cooperative uses certain of these agreements to be able to take power from certain of its power purchase agreements and the wholesale power market. In the opinion of management, the Cooperative will be able to use these contracts to provide service to the Class A all requirements members in accordance with these agreements.

Note 11 - Commitments and Contingencies (Continued)

Rate Filing Application - On August 7, 2005, the ACC approved the Cooperative's application for a rate increase to be implemented over a two-year period (the Order). Phase one became effective September 1, 2005 and resulted in a 12.44% increase; phase two became effective September 1, 2006 and resulted in a 1.5% increase; phase three became effective September 1, 2007 and resulted in a 1.5% increase. As discussed in Note 2 (Revenues, purchased power and fuel costs), the Order approved a fuel and purchased power cost adjustor. The Order also approved a demand side management (DSM) adjustor in the anticipation of the adoption of DSM rules by the ACC and the potential that the Cooperative may engage in DSM programs. The DSM adjustor would allow the Cooperative to recover the cost of the DSM programs. The Cooperative will be filing a new rate application with ACC in 2009.

California Power Sales - ***Collateral Security*** - When the Cooperative entered into scheduling coordinator agreements with the California Independent System Operator (ISO) and the California Power Exchange (CPX) in 2000 for the sale of energy into California, the ISO and CPX required the Cooperative to provide security in the form of irrevocable letters of credit to be drawn against in the event of default by the Cooperative, totaling $3,500,000. Pursuant to a November 2008 FERC order, the letters of credit were released in January 2009.

The core participants of the CPX were also required to provide an additional level of collateral security in the form of performance bonds executed by a surety on behalf of the core participants. The Cooperative in conjunction with the other core participants entered into an indemnity agreement with a surety for the issuance of performance bonds totaling $20,000,000. The Cooperative's indemnity to the surety is limited to only the amount of loss and expenses caused by the Cooperative's default as provided for in the agreement with the CPX. At this time, the CPX is in bankruptcy and no longer conducts transactions and the Cooperative withdrew as a core participant. The bonds were seized by the State of California in 2001 and the CPX is litigating their return on behalf of its creditor participants, including the Cooperative.

California Power Sales - ***California Refunds*** - In response to complaints about sharp price increases for wholesale electricity sold in single price auction markets operated by the ISO and the CPX, the FERC opened an investigation under section 206 of the Federal Power Act (FPA) to determine whether rates in those markets were just and reasonable. It determined under FPA section 206(b) that excessive rates charged in those markets between October 2, 2000 and June 20, 2001 (regular refund period) would have to be refunded. The Cooperative stopped selling into the California markets in early January 2001. On July 25, 2001, the FERC ruled that all sellers in the ISO and CPX markets, including government utilities and the Cooperative, the only electric cooperative involved, who are otherwise exempt from its regulatory jurisdiction, would also have to make refunds. Government entities and the Cooperative appealed the FERC's decision to the 9th Circuit Court of Appeals, who ruled on September 6, 2005, in Bonneville Power Administration v. FERC, that FERC does not have jurisdiction over wholesale energy sales made by government entities and by non-public utilities. This decision is now final.

Note 11 - Commitments and Contingencies (Continued)

Following the jurisdictional ruling in the 9th Circuit Court of Appeals, some California investor-owned utilities and the California Electricity Oversight Board (California Parties) filed lawsuits in March 2006 in federal district court against the non-jurisdictional entities including the Cooperative. These suits were dismissed for lack of federal jurisdiction, and refiled in California State court, in the complex case division of the county of Los Angeles. This case was thereafter dismissed as to AEPCO, without prejudice. This dismissal is being appealed. The suits seek refunds for sales to the ISO and CPX between May 1, 2000 and October 1, 2000 (early refund period) and October 2, 2000 and June 20, 2001 (regular refund period). Using the methodology accepted by FERC for calculating the refund liabilities of the participant sellers, the estimate of the Cooperative's liability, related to the regular refund period, would be approximately $9,000,000, less unpaid accounts receivable of approximately $2,500,000 resulting from the Cooperative's participation in the California market as a participant seller, and other miscellaneous allowances and interest. The Cooperative is unable to develop an estimate for the amount of the refunds that might be due for the early refund period. The Cooperative, based on the progress of the litigation, is unable to determine whether the likelihood of an unfavorable outcome is either probable or remote and has not recorded a contingent liability. The Cooperative disagrees with the basis of the claims and intends to vigorously contest this litigation.

Fuel Procurement Contracts - ***Coal Supply Agreements*** - To ensure an adequate fuel supply, the Cooperative enters into various long-term fuel contracts. At December 31, 2008, these contracts consist of:

- A 36-month contract, effective January 1, 2009. The terms of the contract require the Cooperative to purchase a minimum of 1,100,000 tons during each year of the contract.
- A 12-month contract, effective January 1, 2009. The terms of the contact require the Cooperative to purchase a minimum of 250,000 tons.
- A 12-month contract, effective January 1, 2009. The terms of the contract require the Cooperative to purchase 200,000 tons. However, the Cooperative has resold part of the contract quantity, and will also likely resale the remaining tons.

Rail Transportation Agreement - The Cooperative's rail transportation contracts expired on December 31, 2008. Once it was evident new agreements could not be reached, the Cooperative became a railroad common carrier customer. As such, all the rights and duties of the Cooperative and the railroad are governed by tariffs. Believing the tariff rates unjust, the Cooperative in 2008 filed a complaint with the Surface Transportation Board (STB) seeking the establishment of reasonable rates and other terms for unit train coal transportation service.

Coal Railcar Lease Agreements - To provide for the shipment of the coal supply, the Cooperative entered into lease agreements for the lease of coal railcar trainsets (See Note 15 - Coal Railcar Trainsets).

Note 11 - Commitments and Contingencies (Continued)

Coal Railcar Maintenance Agreement - The Cooperative entered into a 10-year railcar maintenance service agreement, effective December 17, 2002, for the maintenance of the coal railcar trainset leased under the 20-year lease agreement (See Note 15 - Coal Railcar Trainsets). The agreement shall continue for successive 12-month terms unless the agreement is cancelled or the last car covered by the agreement is released. The Cooperative has leased property at its generating station to the company performing the railcar maintenance. The term of the property lease coincides with the railcar maintenance agreement.

Personnel Staffing Agreement - The Cooperative has a personnel staffing agreement with Sierra, whereby Sierra provides personnel staffing services for all positions except certain key staff and management positions, who are employees of the Cooperative (See Note 17). The personnel staffing agreement provides that the Cooperative shall pay for the actual and verifiable costs incurred by Sierra for personnel, materials, supplies and all other direct, indirect and overhead costs incurred by Sierra in carrying out its responsibilities under the personnel staffing agreement. The term of the staffing agreement is for five years from August 1, 2001. The agreement is automatically extended for five successive years unless terminated by either party no later than two years prior to the conclusion of such fifth contract year. Neither the Cooperative nor Sierra gave the two-year advance notice of termination, thereby extending the agreement for an additional five-year term.

Approximately 43% of the personnel employed by Sierra are subject to a collective bargaining agreement. Sierra entered into a five-year collective bargaining agreement, effective March 1, 2005.

Office Facilities and Machinery and Equipment Lease Agreements - The Cooperative has entered into lease agreements with Sierra and SWTC, whereby Sierra and SWTC lease the Cooperative's office facilities and substantially all of its nongenerating machinery and equipment (See Notes 15 and 17).

Natural Gas Sales Agreement - The Cooperative has entered into an agreement with Sierra for the purchase or sale of natural gas at the then prevailing market price for natural gas. The transactions under the agreement are intended to be mutually beneficial to both parties, whereby the supply of natural gas of one party in excesses of its current demand can be sold to the other party to enable it to better match its demand. The agreement became effective March 17, 2003 and continues in effect until terminated by either party upon 30 days written notice (See Note 17).

Letters of Credit - Letters of credit issued by CFC in the amounts of $1,653,750, $2,000,000 and $2,043,101, were obtained by the Cooperative for the purpose of providing credit support for a power purchase agreement with Griffith Energy LLC, providing credit support for a power purchase agreement with Powerex Corporation and for a five-year lease with Marquette Equipment Financing, respectively. The letter of credit issued to Griffith Energy LLC is subject to annual renewals with the last expiration date not extending past January 31, 2015. The letter of credit issued to Powerex Corporation is subject to annual renewals with the last expiration date not extending past September 30, 2010. The Marquette

Note 11 - Commitments and Contingencies (Continued)

Equipment Financing letter of credit was issued on June 5, 2008 with an expiration date of March 31, 2012. The interest rate if draws were to occur will be equal to a fixed rate set by CFC, not to exceed the "Prevailing Bank Prime Rate", as published in the "Money Rates" column of the Wall Street Journal, plus one percent per annum. As a condition of the letters of credit, the Cooperative is required to remain in compliance with the terms and conditions of the Consolidated Mortgage and Security Agreement (See Note 8).

Lines of Credit - The Cooperative maintains a line of credit with CFC maturing March 2, 2011. As of December 31, 2008, the line of credit was for $25,000,000. The interest rate on advances is equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the "Prevailing Bank Prime Rate" published in the "Money Rates" column of The Wall Street Journal, plus one percent per annum. The bank prime rate at December 31, 2008 was 3.25%.

The Cooperative also maintains a line of credit agreement with CFC for $250,000 as part of its credit card program. The agreement remains in effect until terminated by either party with a 90-day notice. No amounts were drawn under this line of credit for the years ended December 31, 2008 and 2007.

Capital Lease - Capital lease property and the related liabilities are in substance asset purchases. Assets and liabilities under capital leases are recorded at the lesser of the present value of the minimum lease payments or the fair value of the assets. The assets are amortized over their related lease terms or their estimated useful lives, whichever is less. On December 22, 2005, the Cooperative entered into a master lease agreement to finance the purchase and installation of an enterprise resource planning software (ERP) system. To finance additional upgrades and enhance features of the ERP system as well as to take advantage of improved lease rates, the Cooperative incorporated the initial lease schedules with additional funding into a new lease schedule dated June 4, 2008. The initial period of the lease is twenty (20) quarters starting April 1, 2009. Future minimum lease payments are as follows:

2009	$ 1,621,421
2010	1,621,421
2011	1,621,421
2012	1,445,395
2013	795,601
Total minimum lease payments	7,105,259
Less amount representing interest	1,193,020
Present value of minimum lease payments	5,912,239
Less current portion	1,260,950
	$ 4,651,289

Note 12 - Patronage Capital

Patronage Capital Allocation - In accordance with the Cooperative's bylaws, net margins are accounted for on a patronage basis in the following sequence:

- Offset prior year's unallocated accumulated losses.
- Assign to Members' accounts as credits based on specific excesses of revenues over operating costs and expenses.

Patronage Capital Retirement - RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25% of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40% of the total assets of the Cooperative. There were no retirements for 2008 and 2007.

Note 13 - Income Tax Status

The Cooperative is exempt from income taxes under the provisions of Section 501(c)(12) of the Internal Revenue Code. Pursuant to FSP FIN 48-3, management has elected to defer the application of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, to fiscal years beginning after December 15, 2008. For the years ended December 31, 2008 and 2007 the Cooperative has accounted for uncertain tax positions in accordance with FASB Statement No. 5, Accounting for Contingencies, whereby the effect of the uncertainty would be recorded if the outcome was considered probable and was reasonably estimatable. As of December 31, 2008 and 2007, the Cooperative has no provision for income taxes.

Note 14 - Retirement Plans

The Cooperative has a defined benefit pension plan covering substantially all of its employees. Pension benefits are provided through participation in the National Rural Electric Cooperative Association (NRECA) Retirement and Security Program. The Cooperative contributes a percentage of salaried and union employees' earnings to the program, as prescribed by NRECA. Contributions made to this plan approximated $277,000 and $208,000 for the years ended December 31, 2008 and 2007, respectively. The Cooperative's policy has been to fund retirement costs annually as they accrue.

This multi-employer plan is available to all member cooperatives of NRECA. Information concerning the Cooperative's proportionate share of the excess, if any, of the actuarially computed value of vested benefits over the pension plan's net assets is not available from NRECA; the plan administrator.

The Cooperative also offers participation in the NRECA SelectRE Pension Plan to all employees meeting certain minimum service requirements. This plan has 401(k) salary deferral features. Under this plan, the Cooperative matches a percentage of the employees' contributions to the plan. The Cooperative's contributions to the plan were approximately $58,000 and $52,000 for the years ended December 31, 2008 and 2007, respectively.

Note 15 - Operating Leases

Commercial office building - In 1999, the Cooperative entered into a noncancelable lease agreement for the lease of a commercial office building (office lease). The initial lease term is for a period of ten years with a renewal option to extend the term of the lease for an additional five years. The Cooperative has subleased the building to Sierra and other tenants. The term of the lease with Sierra is for 89.5 months and commenced on August 1, 2001. Rent expense for the lease of the commercial office building was approximately $217,000 and $216,000 for the years ended December 31, 2008 and 2007, respectively, and is included in administration and general on the accompanying statements of revenues and expenses and unallocated accumulated margins. Rental income received from the sublease of the commercial office building was approximately $112,000 and $251,000 for 2008 and 2007, respectively. In 2008, the Cooperative did not renew the agreement and terminated the lease January 14, 2009.

Computer equipment - The Cooperative entered into master lease agreements for the lease of substantially all the Cooperative's personal computers and peripheral equipment. Individual certificates of acceptance (COAs), underlying the master lease agreements, are entered into as groups of computers and equipment are delivered. The terms of the COAs are for up to four years. Rent expense for the lease of the computer equipment was approximately $401,000 and $466,000 for the years ended December 31, 2008 and 2007, respectively, and is included in administration and general on the accompanying statements of revenues and expenses and unallocated accumulated margins.

Coal railcar trainsets - The Cooperative entered into lease agreements for the lease of coal railcar trainsets. Lease payments are included as a component of fuel expense. At December 31, 2008, these lease agreements consist of:

- A 20-year lease agreement, effective December 17, 2002. Lease payments under this agreement totaled approximately $400,000 in 2008 and 2007. The Cooperative has the option of canceling this agreement effective December 31, 2012 subject to the following: (1) the Cooperative notifies the lessor in writing on or before 180 days prior to the effective date of the termination, and (2) the Cooperative pays an additional amount of $5,971 per car for each car terminated.
- A 60-month lease agreement, effective January 1, 2004. Lease payments under this agreement totaled approximately $522,000 and $569,000 for 2008 and 2007, respectively.
- A 72-month lease agreement, effective January 1, 2003. This lease provides for the periodic use of a coal railcar trainset. Lease payments under this agreement totaled approximately $62,000 and $140,000 for 2008 and 2007, respectively.
- A 36-month lease agreement, effective August 1, 2006. This lease provides for the use of coal railcars. Lease payments under this agreement totaled approximately $1,175,500 and $1,180,500 for 2008 and 2007, respectively.

Note 15 - Operating Leases (Continued)

The following summarizes the future minimum lease payments under operating leases that had initial or remaining lease terms in excess of one year at December 31, 2008:

2009	$ 1,088,225
2010	399,600
2011	399,600
2012	399,600
2013	399,600
Thereafter	3,596,400
	$ 6,283,025

Note 16 - Concentration of Customers and Credit Risk

Revenue and accounts receivable for the year ended December 31, 2008 included amounts from four customers, whom each individually represented more than 10% of the total operating revenue and accounts receivable. Revenue from these customers collectively represented approximately 83% of total operating revenue for 2008. The amounts owed from these customers collectively represented approximately 83% of the total accounts receivable balance at December 31, 2008.

Revenue and accounts receivable for the year ended December 31, 2007 included amounts from four customers, whom each individually represented more than 10% of the total operating revenue and accounts receivable. Revenue from these customers collectively represented approximately 85% of total operating revenue for 2007. The amounts owed from these customers collectively represented approximately 84% of the total accounts receivable balance at December 31, 2007.

Note 17 - Related Parties

The Cooperative is a Class B member of Sierra and SWTC. Class B members of Sierra are collectively represented by one director seated on Sierra's board of directors. Class B members of SWTC are also collectively represented by one director seated on SWTC's board of directors. Directors for both SWTC and Sierra are entitled to one vote on each matter submitted to a vote at a meeting of the members. The Cooperative's investment in Sierra was $3,000,000 as of December 31, 2008 and 2007 and is carried at cost. The Cooperative's patronage allocation from SWTC was approximately $2,700,000 at December 31, 2008 and 2007.

Note 17 - Related Parties (Continued)

The Cooperative has entered into an agreement with Sierra, whereby Sierra provides personnel staffing services (See Note 11 - Personnel Staffing Agreement). For 2008 and 2007, the Cooperative recorded expenses for personnel staffing services from Sierra totaling approximately $22,197,000 and $20,193,000, respectively.

The Cooperative has entered into lease agreements with SWTC and Sierra for the lease of office facilities and machinery and equipment (See Note 11 - Office Facilities and Machinery and Equipment Lease Agreements). For 2008, rents received by the Cooperative from SWTC and Sierra totaled approximately $909,000 and $1,416,000, respectively. For 2007, rents received by the Cooperative from SWTC and Sierra totaled approximately $832,000 and $1,311,000, respectively.

The Cooperative has entered into agreements with SWTC for transmission service (See Note 11 - Network Service Agreement (Class A) and Bundled Transmission Service Agreements). For 2008 and 2007, the Cooperative recorded transmission expenses from these agreements totaling approximately $14,386,000 and $19,805,000, respectively.

The Cooperative has entered into an agreement with Sierra for the sale of natural gas (See Note 11 - Natural Gas Sales Agreement). No revenues were recorded under this agreement for 2008 and 2007.

As of December 31, 2008, the Cooperative has recorded accounts payable to SWTC and Sierra totaling approximately $5,845,000 and $20,693,000, respectively, and accounts receivable from SWTC and Sierra totaling approximately $5,512,000 and $21,742,000, respectively. As of December 31, 2007, the Cooperative had recorded accounts payable to SWTC and Sierra totaling approximately $2,038,000 and $0, respectively, and accounts receivable from SWTC and Sierra totaling approximately $1,496,000 and $1,709,000, respectively. The net receivable for 2008 and 2007 are included in the accompanying balance sheets in accounts receivable.

Note 18 - Asset Retirement Obligations

The asset retirement obligation related to generation assets at December 31 consists of the following:

	2008	2007
Liability at January 1	$ 1,439,346	$ 2,447,767
Accretion expense	95,185	89,290
Reduction in estimate	-	(1,210,453)
Liabilities incurred	120,181	112,742
Liability at December 31	$ 1,654,712	$ 1,439,346

C

DIRECT TESTIMONY OF
GARY L. GOBLE
ON BEHALF OF
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
GENERAL RATES APPLICATION

I. POSITION AND QUALIFICATIONS

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

A. My name is Gary L. Goble. I am a consultant with the firm of Management Applications Consulting, Inc. ("MAC"). MAC's primary office is 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609. My office is located at 11405 Cezanne Court, Austin, Texas 78726.

Q. In what capacity and on whose behalf are you employed in this proceeding?

A. I have been retained to provide consulting services and testimony relating to the costs of providing service and the rates charged to the Class A Members of Arizona Electric Power Cooperative, Inc. ("AEPCO"). In this proceeding, I am testifying on behalf of AEPCO and, in particular, in support of Schedules G and H of the rate filing package. This testimony addresses the allocation of costs to AEPCO's two partial-requirements and four all-requirements Class A Members. Furthermore, relying upon the results of my cost allocation, I have prepared and testify in support of proposed rates that are designed to recover these allocated costs.

Q. Please outline your education, experience and professional qualifications.

A. I am a consultant with more than 35 years of experience in regulatory matters. I have undergraduate and graduate degrees in business and have worked as a staff analyst for two regulatory commissions and as a consultant to the utility industry. I have testified before state and local regulatory agencies and boards on numerous occasions. The primary focus of my work experience has been in the areas of cost analysis, pricing and economic analysis. Please refer to Exhibit GLG-1 for more detailed information concerning my education, experience and professional qualifications.

II. ALLOCATED COST OF SERVICE

Q. Please describe what is meant by the phrase "allocated cost of service".

A. "Allocated cost of service" refers to the process by which all of a utility's revenue requirements are assigned, or allocated, among customers or customer classes on some rational basis. An allocated cost of service study identifies the detailed cost components that comprise a utility's revenue requirement, as well as the cost drivers that influence or cause these costs to be incurred. Once the cost drivers associated with costs are identified, the costs are allocated based upon the notion of cost causation. In this manner, customers who cause the costs to be incurred bear the responsibility of paying for those costs. Because all components that make up the utility's revenue requirement are allocated to customers or classes, these studies are often referred to as "fully distributed" cost of service studies.

Q. Generally, what are the steps involved in conducting an allocated cost of service study?

A. The steps employed to conduct an allocated cost of service study are functionalization, classification and allocation. Functionalization is the arrangement of costs according to major service functions, such as production, transmission or distribution. Functionalization is generally accomplished by the process of recording investment and expenses in accordance with a prescribed uniform accounting system, such as the Rural Utilities Service Uniform System of Accounts which is used by AEPCO. For example, production plant is booked in accounts 301 through 346, and production expenses are booked in accounts 500 through 557. Other costs relating to general plant, customer-related expenses and administrative and general expense are similarly booked in specific accounts that recognize the underlying purpose of the expenditure.

Classification further refines functionalized costs into categories to which general cost drivers can be ascribed. These categories are generally demand, energy, customer and revenue classifications. For example, fuel costs arise as a result of energy consumption and are, therefore, classified as energy-related costs. Grouping functionalized costs into cost classifications allows analysts to develop factors for apportioning (*i.e.*, allocating) costs to customers or customer classes.

The final allocation step employs utility metrics that reflect customer or class contributions to the cost drivers as the basis for allocating costs. Class contribution to system peak demands may be used to allocate production plant. Energy sales adjusted for losses may be used to allocate fuel costs.

Q. Was the allocated cost of service process described above used in connection with AEPCO's rate application?

A. Yes, it was. However, as I discuss later, AEPCO's cost of service methodology is also the product of significant input from its members and also reflects the specific service generation resource obligations to its partial-requirements and all-requirements members.

Q. Is this allocated cost of service process consistent with the Arizona Corporation Commission's rate application filing requirements?

A. Yes. These steps are recognized in Schedule G of the Commission's rate filing requirements. For example, Schedules G-5 and G-6 provide for the functionalization of rate base and expenses and Schedules G-3 and G-4 provide for the allocation of rate base and expenses to customer classes. However, as discussed later, not all of the Schedule G filing requirements are applicable to AEPCO in light of its organizational structure and customer makeup. Additionally, AEPCO's generation cost functionalization analysis is specially tailored to account for the differing cost responsibilities between the two partial-requirements Class A Members—Mohave Electric Cooperative, Inc. ("MEC") and Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC")—and four all-requirements Class A Members.

Q. Please describe the generation cost functionalization utilized in allocating AEPCO's cost of service.

A. AEPCO's generation cost functionalization analysis employs three functional categories: Base Resources, Other Existing Resources and Additional ARM Resources.

The first category, Base Resources, is comprised of AEPCO's coal-fired Apache Steam Units 2 and 3 and certain base load purchased power contracts (such as the Colorado River Storage Project ("CRSP") and the Parker Davis Project, which are part of the Western Area Power Administration ("WAPA") power). MEC and SSVEC participate in and receive output from these base load resources in fixed proportions according to their allocated capacity percentages as set forth in their respective partial-requirements agreements. Specifically, MEC is entitled to 35.8% of the base load supply, SSVEC is entitled to 31.7% and the four all-requirements members (which are treated as a single entity for cost allocation and rate design purposes) are entitled to the remaining 32.5%. Consequently, each partial-requirements member and the collective all-requirements members bear their percentage share of the costs of these base load resources.

The second category—Other Existing Resources—primarily consists of AEPCO's gas-fired units at Apache and other operational purchases. Similar to the assignment of Base Resources, the capital and non-energy-related operating costs of Other Existing Resources are assigned to members in accordance with their allocated capacity percentages. Because these resources are utilized by the partial-requirements and all-requirements members as needed, the energy-related costs of these resources are assigned to members on an "as used" basis as determined by the hourly dispatch model discussed below. The final category—Additional ARM Resources—is utilized exclusively by the all-requirements members. An example of this type of resource would be a seasonal peaking purchased power contract secured specifically to meet ARM loads.

Q. How are these categories used to allocate costs?

A. In order to allocate the Other Existing Resources and Additional ARM Resources costs consistent with cost causation principles, AEPCO has used an hourly matching of load requirements against available supply resources to match the partial-requirements members' hourly load schedules to the available hourly power supplies. When the partial-requirements members' scheduled load exceeds their allocated share of capacity available from Base Resources, the remaining load requirements are then matched to their share of AEPCO's Other Existing Resources. Similarly, the all-requirements members' hourly loads are initially matched to their allocated hourly Base Resources. Any unmet demand is matched first to their share of Other Existing Resources and then to other Additional ARM Resources. If scheduled loads are less than Base Resources, the available unused Base Resource capacity is available to other members at market prices. By assigning the costs of the three supply functions (Base Resources, Other Existing Resources and Additional ARM Resources) on an hour-by-hour basis, AEPCO simultaneously functionalizes the expenses of these resources and allocates the associated costs to MEC, SSVEC and the all-requirements members.

Q. Please describe Schedules G-1 and G-2 of AEPCO's rate filing.

A. Schedule G-1 summarizes AEPCO's margins and rate of return for the adjusted test year at present rate levels. Although AEPCO's revenue requirements do not employ a rate base to develop returns, this schedule shows the effective level of return to comport with the filing requirements of the Commission. Schedule G-2, page 1 provides similar information at the proposed rate level. Schedule G-2, page 2 refers to the derivation of proposed rates on Schedule G-4, page 1.

Q. Please describe Schedule G-3.

A. Schedule G-3 concerns the allocation of rate base to classes of service. Because AEPCO's revenue requirement is not driven by a rate of return on rate base (*i.e.*, AEPCO is a non-profit, member-owned cooperative), this schedule is not applicable.

Q. Please describe Schedule G-4.

A. Schedule G-4, page 1 provides the derivation of revenue requirements and rates for MEC, SSVEC and the all-requirements members. Costs which have been functionalized as Base Resources, Other Existing Resources and Additional ARM Resources on Schedule G-6 have also been further categorized as fixed costs, capacity-related operation and maintenance expenses or energy-related expenses on Schedule G-6, page 5. After netting certain adjustments, including other revenues and the revenues received from the transfer and use of resources by other members, against the energy-related costs on Schedule G-4, page 2 revenue requirements by customer by function are aggregated on Schedule G-4, page 1. These cost groupings are then employed on lines 35 through 41 of Schedule G-4, page 1 to develop the Fixed Charge and O&M

Charge dollar amounts for MEC and SSVEC, as well as the Fixed Charge Rate and the O&M Charge Rate for the all-requirements members (lines 36-38). In addition, by identifying and grouping energy costs by resource function, separate energy charges for MEC, SSVEC and the all-requirements members were developed which reflect the specific supply resource costs attributable to each of these Class A Members (lines 39-41).

Q. Please describe Schedule G-5.

A. Schedule G-5 concerns the development and presentation of rate base by function. As previously explained, AEPCO does not employ a rate base to develop its revenue requirement. Therefore, this schedule is not applicable.

Q. Please describe Schedule G-6.

A. Schedule G-6 provides the detailed functionalization of expenses to Base Resources, Other Existing Resources and Additional ARM Resources. Schedule G-6, page 1 summarizes the account-by-account assignment of expenses after reclassifications have been made to the three resource functions. Schedule G-6, page 2 provides the account-by-account assignment of booked expenses to the three resource functions. Production fuel expense, account 501, is by far the single largest component of costs. This account reflects the coal costs associated with Apache Steam Units 2 and 3 and is functionalized to Base Resources. Similarly, operations and maintenance expenses associated with the Base Resources units (accounts 502, 505, 506, 509, 511, 512, 513 and 514) are functionalized to the Base Resources function. Production fuel expense (account 547) is the fuel costs of the Other Existing Resources and is functionalized accordingly. The operations and maintenance expenses associated with Other Existing Resources (accounts 546, 548, 549, 552, 553 and 554) are also assigned to Other Existing Resources in a consistent manner.

Purchased Power expense (account 555) was assigned to functions based upon contractual obligations. That is, the energy and demand costs of the WAPA contracts were assigned to Base Resources since these agreements are firm base load supply contracts. However, the members have agreed that the costs associated with the South Point Energy Center ("Calpine"), PPL Energy Plus ("Griffith") and Powerex contracts are all-requirements member resources and, thus, on a going forward basis, the costs of these PPAs should be assigned to Additional ARM Resources. The remaining purchased power costs reflect purchases made to serve the entire AEPCO load and are, therefore, functionalized as Other Existing Resources.

System Control and Load Dispatching (account 556), Other Expenses (account 557) and Transmission of Electricity by Others (account 565, excluding a directly assigned amount associated with the Liberty to Marana transmission transaction) were functionalized on the basis of the proportions of energy from each of the three resource types insofar as the scheduling and transmission of this energy is the cost driver for these costs. Station Expense (account 562), Underground Line Expense (account 564) and Maintenance of Station Equipment (account 570) were functionalized on the basis of the related functionalization of fuel expense accounts 501 and 547. Administrative and General Expense and General Plant Expense were functionalized on the basis of the functionalized labor component of the other operation and maintenance expense accounts.

The remaining cost components of AEPCO's revenue requirements were similarly assigned to functions based upon the appropriate cost drivers. Depreciation expense was assigned based upon the amount of depreciation associated with each generation unit. The depreciation associated other non-generating equipment was pro-rated on the basis of directly determined depreciation expense by function. Similarly, Interest on Long-Term Debt was directly calculated by function and assigned accordingly with the small amount of indirect interest functionalized on a pro-rata basis. The remaining other interest and deductions were addressed in the same manner. Total booked expenses by function were then totaled and are set forth on line 59 of Schedule G-6, page 2.

Q. Please describe how the pro forma adjustments made by AEPCO were functionalized.

A. Schedule G-6, page 3 provides the distribution of AEPCO's pro-forma adjustments to test year expenses to the functions of Base Resources, Other Existing Resources and Additional ARM Resources. On this page, each of the pro forma adjustments described by Mr. Pierson has been assigned to the specific account and resource function affected by the adjustment.

The labor expense adjustment has been distributed to the various operation and maintenance accounts and resource functions on the basis of the booked labor by account which was, in turn, functionalized on the same basis as the adjusted expenses set forth on Schedule G-6, page 1. The labor adjustment affects numerous accounts and resource functions to which labor costs are booked. The Base Resources function of fuel expense (account 501) was adjusted to reflect the various pro-forma adjustments described in Mr. Pierson's testimony. The Base Resources function of steam expense (account 502) was adjusted for the mercury control pro forma adjustment. The Other Existing Resources and Additional ARM Resources functions of purchased power expense (account 555) were decreased to reflect (1) the pro forma adjustment for the expiration of the PNM PPA, (2) decreases in purchased power costs associated with increased use of Other Existing Resources resulting from the expiration of the City of Mesa ("Mesa") contract and (3) the removal and/or modification of the purchased power agreements as discussed by Mr. Pierson. The Base Resources function of transmission of Electricity by Others (account 565) reflects the reduction in point-to-point costs associated with the Salt River Project adjustment, to reflect a reduction in system control and load dispatching costs and to reflect the decrease in Mesa transmission expenses. The Other Existing Resources function of maintenance of electric plant (account 513), maintenance of structures (account 552) and maintenance of generating and electric equipment (account 553) was reduced to reflect each account's pro rata portion of the maintenance outage adjustment. The Depreciation expense adjustment and adjustment for Interest on Long-Term Debt were assigned to functions based upon the associated costs from Schedule G-6, page 1. Finally, the adjustment for interest associated with the SAP software was assigned to functions based upon the functionalization of depreciation expense.

Total pro forma adjustments by function were totaled and are set forth on line 59 of Schedule G-6, page 3.

Q. Please describe how the reclassification of expenses made by AEPCO was functionalized.

A. Schedule G-6, page 4 provides information concerning the distribution of AEPCO's reclassifications of test year expenses to the functions of Base Resources, Other Existing Resources and Additional ARM Resources. The reclassified amounts by account were removed from the functional costs using the same basis as the costs were initially assigned to the respective functions. Coal legal fees included in the Base Resources function of fuel expense (account 501) were removed from this account and reclassified to the Base Resources function of administrative and general expenses. In addition, property taxes were removed (*i.e.*, reclassified) from the various functions of those production operations and maintenance expense accounts in which these costs have been booked. This adjustment affected fuel expense (account 501), steam expenses (account 502), electric operation expenses (account 505), generation operation expenses (account 548) and administrative and general expenses. The reclassifications made to the Base Resources and Other Existing Resources functions of system control and load dispatching (account 556), other power supply expenses (account 557) and transmission of electricity by others (account 565) reflects the removal of Southwest

Transmission Cooperative revenue associated with load control and system dispatch. Finally, the reclassifications made to taxes on line 47 of Schedule G-6, page 4 removed property taxes from the Base Resources and Other Existing Resources functions of various O&M accounts and identified these costs as taxes for ratemaking purposes. Mr. Pierson explains the reclassifications proposed by AEPCO. Total reclassifications by function are totaled and set forth on line 59 of Schedule G-6, page 4.

Q. Please describe how member requirements by function by classification were developed on Schedule G-6, page 5.

A. Schedule G-6, page 5 sets forth the functionalized costs by account provided on Schedule G-6, page 1 with additional breakdowns of adjusted account balances into Fixed, O&M and Energy classifications. This allows the grouping of costs into components useful in the development of rates in Schedule G-4, page 1. As one would expect, the bulk of the operations and maintenance expenses other than fuel and purchased power are classified to O&M. Fixed costs are those costs that do not vary with the level of service. For example, while the vast majority of fuel costs are energy-related, a portion of fuel expense in account 501 is related to natural gas used for flame stabilization in the coal fired generation units and is, thus, fixed in nature rather than energy-related. Similarly, while most of the costs of gas used in the gas-fired Other Existing Resources are energy-related, a portion of those costs is gas reservation charges and is, therefore, fixed, as opposed to energy-related. Property taxes are another component of costs that are considered fixed. The demand component of purchased power costs is also considered to be fixed in nature and is classified as such, while the variable portion of purchased power is classified as energy-related. Depreciation and interest are fixed costs because they do not change with the level of energy sales.

Q. **Schedule G-6, page 5 includes revenue credits that are netted against total expenses. Please describe these revenue credits and explain how they are functionalized and classified.**

A. As indicated on Schedule G-2, page 1 (lines 3 and 4) and Schedule G-6, page 5 (line 66) AEPCO receives about $12.1 million of Non-Member and Other Operating Revenues which is used to offset an equal portion of Class A Member revenue requirements. These revenue credits are comprised of Firm Contract Revenues from ED2 firm sales, Economy Energy Sales from AEPCO generation assets, Scheduling Revenues for scheduling services provided to all-requirements members and Other Operating Revenues from miscellaneous sources. The Firm Contract Revenues arise from the sale of capacity and energy from AEPCO's Base Resources and, thus, fixed (*i.e.*, capacity-related) revenue is classified as Fixed and the variable charge revenue is classified as Energy within the Base Resources function. Economy Energy revenue is entirely variable charge revenue and results from both Base Resources sales and from sales from Other Existing Resources. Scheduling Revenues are provided from scheduling services provided exclusively to all-requirements members and are, therefore, functionalized entirely to Additional ARM Resources and classified as O&M related. Other Operating Revenues are provided from sources such as loss charges, banking charges and certain reserve sharing revenues. Because Other Operating

Revenues arise from all AEPCO generation resources, these revenues are functionalized and classified on the basis of Total Expenses prior to Revenue Credits.

Q. How are total Class A Member revenue requirements determined?

A. All classified and functionalized operations and maintenance expenses, depreciation, taxes, interest and other charges are totaled on line 59 of Schedule G-6, page 5. Revenue credits set forth on line 66 are deducted from total expenses and margins are added on line 68. Margins are classified as fixed costs and are assigned to functions on the basis of the total costs of service by function excluding margins. The resulting Class A Member revenue requirements by cost classification and function are provided on line 70 of Schedule G-6, page 5.

Q. Please describe Schedule G-7, page 1.

A. Schedule G-7 summarizes the functionalization factors employed in the assignment of costs in Schedules G-4 and G-6.

III. RATE DESIGN

Q. Mr. Goble, are you also sponsoring Schedules H-1 through H-5?

A. Yes, I am.

Q. Please describe Schedule H-1.

A. Schedule H-1, page 1 summarizes total member and other tariff sales revenues at present and proposed rates, as well as the proposed dollar and percent increases for the test year.

Q. Please describe Schedule H-2.

A. Schedule H-2, page 1 compares present and proposed revenues by member for Class A members and firm contract sales. Schedule H-2, pages 2 through 4 provides billing determinant information used to develop the rates set forth in Schedule G-4, page 1. Schedule H-2, page 2 provides unadjusted MW and MWH sales by Class A Member by month for the test year. Schedule H-2, pages 3 and 4, provides adjusted MW and MWH sales by Class A Member by month for the test year. Schedule H-2, page 4 also provides the adjusted kWh sales by member which are further indentified by resource function (*i.e.,* Base Resources, Other Existing Resources and Additional ARM Resources).

Schedule H-2, pages 5 through 10, provides detailed monthly rate revenue information at actual present and proposed rates for each Class A Member. These pages employ the actual Purchased Power and Fuel Adjustor Clause ("PPFAC") adjustor rate by month for the test year and also provide the dollar and percentage impacts of the proposed revenue changes to base rates and total revenue. Page 11 is a recap schedule that provides a summary of actual present and proposed revenues for all-requirements and partial-requirements members. Page 12 provides the average cost per kWh by Class A Member by month at present and proposed rates.

Schedule H-2, pages 13 through 18, provides the same information as pages 5 through 10, except that the PPFAC factor has been synchronized to allow a consistent comparison of present and proposed rate revenues. A consistent "apples-to-apples" comparison of rate impacts would not be possible when comparing revenues produced by actual test year PPFAC factors derived from actual test year fuel and purchased power costs to revenues produced by rates that employ adjusted test year fuel and purchased power costs. For this reason, present revenues are restated, or synchronized, on Schedule H-2, pages 13 through 18, using a PPFAC that reflects adjusted test year fuel and purchased power costs. Page 19 is a recap schedule summarizing the synchronized present revenues for all-requirements and partial-requirements members. Finally, page 20 provides the average cost per kWh for Class A Members at synchronized present and proposed rates.

Q. Please describe Schedule H-3.

A. Schedule H-3, page 1 identifies the changes in representative rate schedules. Lines 1 through 8 set forth the present monthly charges for MEC, SSVEC and the all-requirements members. Lines 10 through 17 provide the proposed rates for these members. Lines 19 through 26 set forth the changes in the monthly rates from the present rates to the proposed rates. Because AEPCO proposes to apply a fixed monthly O&M charge to the partial-requirements members, the present O&M rate per kilowatt for MEC and SSVEC has been recalculated as total monthly charges for the rate comparison provided on line 21. Similarly, the fixed charge per kilowatt of demand for the all-requirements members is proposed to be replaced by two demand billing charges, one for recovery of fixed costs and another for recovery of O&M costs. Therefore, line 22 of this page provides a comparison of the total of the two demand charges. Finally, AEPCO proposes to replace the current single base energy charge of each of MEC, SSVEC and the all-requirements members with multiple base energy charges reflecting the three generation resource functions. Therefore, the present base energy charge is compared with the weighted average proposed energy charges for purposes of calculating the base energy charge changes proposed by AEPCO. These base energy charge changes are set forth on line 26 of Schedule H-3, page 1.

Q. Please explain why Schedules H-4 and H-5 are not applicable to AEPCO.

A. Schedule H-4 requires the filing of typical bill analyses to facilitate a comparison of present and proposed rates at varying consumption levels. AEPCO does not have retail customers and has provided actual month-by-month impacts for each Class A Member in Schedule H-2. That provides the "typical" customer information specifically applicable to each customer. Finally, Schedule H-5 requires the filing of billing activity by block for each rate schedule. As stated, AEPCO does not serve any retail customer classes and AEPCO's present and proposed rates do not contain any rate blocks. Therefore, this schedule is not applicable.

Q. Please summarize AEPCO's proposed rates for Class A Members.

A. As explained by Mr. Pierson, AEPCO has worked closely with its Class A members to develop proposed rate forms that take member input into account. Schedule G-4, page

1, lines 27 through 41, shows the development of the proposed rates. Currently, both MEC and SSVEC pay fixed monthly charges, and AEPCO proposes to continue this type of rate. The monthly fixed charges for MEC and SSVEC of $772,376 and $683,919 are stated as fixed dollar amounts to reflect their respective fixed costs. Because they participate in AEPCO resources at fixed allocated capacity percentages, the fixed costs of MEC and SSVEC will neither increase nor decrease (except as a result of inflation or significant changes in AEPCO's overall cost structure[1]). Therefore, it is fair and reasonable to recover fixed costs from these members on a fixed monthly basis rather than through the application of a demand charge. The fixed costs for each of the three proposed Class A member rates are summarized on lines 2 through 6 of Schedule G-4, page 1. For MEC and SSVEC, these fixed costs are simply divided by 12 to derive the monthly fixed charges. For all-requirements members, AEPCO remains obligated to secure sufficient resources to meet load growth. Therefore, it is fair and reasonable to recover all-requirements members' fixed costs by means of a demand charge as is the typical practice in the electric utility industry. Dividing MEC's and SSVEC's Fixed costs by 12 months yields the monthly Fixed Charges for these two members of $772,376 and $683,919, respectively. Dividing the fixed costs of all-requirements members by their billing demands yields a fixed cost rate of $6.036 per kilowatt of billing demand. As indicated on Schedule H-3, lines 11 through 13, and in Mr. Pierson's testimony, the total proposed all-requirements members' demand charge is the sum of the fixed charge and the O&M charge or $14.05 per kilowatt month.

[1] Neither fixed dollar charges nor charges per kilowatt of demand can address changes in inflation or cost structure. Therefore, to the extent that this is a problem with the application of a fixed charge, it is also a problem with the typical demand charge.

Similar reasoning applies to the development of O&M charges for AEPCO'S Class A Members. After extensive discussions with its members, AEPCO proposes to modify its present O&M charges for the PRM from a charge per kilowatt of demand to a fixed monthly charge. As indicated by the cost assignments set forth on Schedule G-6, page 5, most O&M expenses are directly tied to the level of fixed assets operated and maintained by AEPCO. Therefore, for MEC and SSVEC, which have fixed levels of scheduled load and cost responsibility, these costs do not vary as AEPCO's system demand varies. For this reason, it is fair and reasonable to recover these costs on a fixed dollar basis rather than on the basis of a dollar per kilowatt of demand. The monthly O&M charges for MEC and SSVEC are calculated by dividing the allocated O&M costs shown on Schedule G-4, page 1, line 12, by 12. The resulting O&M charges are $1,410,263 and $1,248,752 for MEC and SSVEC, respectively. For all-requirements members, AEPCO remains obligated to secure sufficient resources to meet load growth and to pay for the resulting changes in operation and maintenance expenses. Therefore, it is fair and reasonable to recover all-requirements members' O&M costs by means of a demand charge as is the typical practice in the electric utility industry. The monthly O&M charge for all-requirements members is calculated by dividing the allocated O&M costs shown on Schedule G-4, page 1, line 12, by the members' billing demands. The resulting O&M charge of $8.016 per kilowatt of billing demand is shown on line 37 of this schedule.

AEPCO is proposing to charge separate energy charges for MEC, SSVEC and the all-requirements members and to further separate these energy charges into Base Resources energy charges, Other Existing Resources energy charges and Additional ARM Resources energy charges. Schedule H-3, page 1, sets forth the proposed changes in the Class A members' rate schedules.

Q. Please explain AEPCO's proposal to apply separate energy charges for Base Resources, Other Existing Resources and Additional ARM Resources.

A. The proposal to implement multiple energy charges is the result of a collaborative process between AEPCO and its members. AEPCO and its member cooperatives have discussed this matter extensively and the member cooperatives have participated in a number of meetings to address the issue of separate energy charges to allocate and to recover the costs of separate supply resources. Separate energy charges recognize cost differences among the Class A Members. For example, as shown on Schedule G-4, page 1, line 38, MEC's Base Resources cost is less than the average Base Resources cost, while the Base Resources cost of SSVEC and the all-requirements members is greater than AEPCO's average system Base Resources cost. Conversely, as shown on line 39 of this page, MEC's average cost per kWh of Other Existing Resources is greater than the average cost of the system and greater than either SSVEC's or the all-requirements members' cost. By differentiating the energy charges among the Class A Members, AEPCO is able to more accurately assign and recover energy costs, which has been a subject of considerable and prolonged controversy among the members. Applying separate energy charges for Base Resources, Other Existing Resources and

Additional ARM Resources ensures a more accurate recovery of costs and, thus, provides rates that are fairer than a blended, average cost alternative.

Q. Please describe AEPCO's proposed PPFAC changes.

A. As explained by Mr. Pierson, AEPCO proposes to work with the Staff of the Commission to develop and refine the administrative procedures and calculations necessary to implement refinements to the PPFAC. AEPCO proposes that its PPFAC employ the same procedures to calculate hourly costs by resource as was used to assign fuel and purchased power costs in Schedule G-6. As previously explained, these procedures match hourly load requirements (either scheduled loads for MEC and SSVEC or actual loads for the all-requirements members) with the allocated capacity available to meet the loads in that hour. Under AEPCO's proposal, costs and usage will be accumulated for all hours in the month for each customer (again, the four all-requirements members are treated as a single entity for this calculation) and total costs and usage for the month will be calculated. Unused available capacity from each resource for each member will be available for use by other members, if needed, and will be priced at the then current market price for that period. Load that is unable to be served from Base Resources will be served by Other Existing Resources for all members in accordance with their respective allocated portions of the supply resources and any remaining unserved all-requirements members' load will be served by Additional ARM Resources. The adjustment mechanism will take into account the costs of tariff load, resource transfers, third-party sales, purchased power costs, the costs of transmission of power by others and will also reduce the recoverable costs by transfer credits and revenues from firm contract and economy energy sales.

Q. Please describe the calculation of the proposed PPFAC bases.

A. The proposed PPFAC bases are calculated in a manner consistent with the manner by which the PPFAC factors will be calculated. Exhibit GLG-2 sets forth the development of the PPFAC base factors. Page 1 of Exhibit GLG-2 summarizes the recoverable fuel and purchased power costs by resource for MEC, SSVEC and the all-requirements members and calculates the fuel and purchased power base rate factors for each resource and member. On this page, the PPFAC bases for Base Resources are set forth on line 4, the PPFAC bases for Other Existing Resources are set forth on line 9 and the PPFAC bases for Additional ARM Resources are set forth on line 14. The average costs of fuel and purchased power from all resources are provided on line 19.

Exhibit GLG-2, page 2 summarizes the energy costs and credits from all resources. As indicated on lines 2 through 7, there are fuel costs associated with sales to tariff load and sales to third parties, as well as costs and credits associated with transfers among the AEPCO members. Also included as recoverable costs are purchased power expenses (account 555) and the costs of firm and non-firm transmission of electricity by others (account 565). Because AEPCO is able to make sales to non-members from Base Resources and Other Existing Resources, the revenue derived from such sales, as shown on lines 21 through 24, is available to reduce the costs of fuel and purchased power that must be recovered from Class A Members.

Pages 3, 4 and 5 of Exhibit GLG-2 set forth the development of energy costs and credits for Base Resources, Other Existing Resources and Additional ARM Resources, respectively, for MEC, SSVEC and the all-requirements members. All information used to develop the bases are provided in and derived from Schedules G-2 and G-6 of AEPCO's rate filing package.

Q. In your opinion, do the rates proposed by AEPCO properly and reasonably reflect the costs of providing service?

A. Yes, they do. The rates have been designed based upon the costs of providing service. The proposed rates also reflect carefully considered input from and the collective thinking of the Class A members after extensive discussion and numerous meetings. The rates, and the underlying cost structure, are the result of an objective and well-reasoned analysis of cost functions and classifications. The functionalization of costs into Base Resources, Other Existing Resources and Additional ARM Resources allows the proposed rates to directly link the functional cost drivers to the resulting costs. For the most part, costs are functionalized on a direct assignment basis: fuel costs from base units are assigned to Base Resources; operation and maintenance expenses of other generation resources are assigned to Other Existing Resources; and purchased power costs attributable to all-requirements members' demands are directly assigned to Additional ARM Resources. Joint and common costs, which by their nature cannot be directly assigned, are allocated to functions using standard, commonly employed and accepted methodologies and/or methods prescribed by member operating agreement.

Similarly, the classification of costs to Fixed, O&M and Energy functions recognizes and closely follows cost causation principles and accepted industry practices. In my opinion, the results of the cost allocations set forth in Schedule G are accurate and reasonable and the rates developed from these costs properly and reasonably reflect the costs of providing service by AEPCO.

Q. In your opinion, are the rates proposed by AEPCO fair and reasonable?

A. Yes, they are. The proposed rates accurately reflect the costs of providing service. As such, they are neither discriminatory nor burdensome upon the Members paying the rates. Members who cause costs to be incurred bear the responsibility of those costs. The underlying logic of the rate design is consistent with generally accepted ratemaking principles. Therefore, I recommend that the rates proposed by AEPCO be approved.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit GLC-1

QUALIFICATIONS AND EXPERIENCE

I graduated from the University of Arkansas at Fayetteville in 1974 with a Bachelor of Science degree in Public Administration. In 1980, I received a Master of Business Administration degree from Saint Edward's University in Austin, Texas. Upon graduation from the University of Arkansas, I was employed by the Arkansas Public Service Commission and held several positions with the Arkansas Public Service Commission staff, including Chief of the Rates Section and Interim Chief of the Finance Section. My activities in these positions included developing and presenting staff analyses and testimony concerning cost allocation studies and rate design for electric, natural gas, water, and telephone utilities; ensuring utility compliance with Arkansas Public Service Commission rate and tariff requirements; and providing supervision and management to staff financial analysts in the determination of utility cost of capital and capital structure.

In 1978, I accepted the position of Manager of Electric and Water Rates in the Economic Research Division of the Public Utility Commission of Texas. In this capacity, I was responsible for staff analyses, testimony, and activities concerning cost analysis, rate design, pricing strategies, tariffs, and econometric applications for regulated utilities.

In 1980, I was employed by Gilbert Associates, Inc. as a Management Consultant. I was promoted to Senior Management Consultant in March 1981 and to Principal Management Consultant in July 1981. In July 1981, I became Manager of Cost and Load Analysis in Gilbert Associates' Austin office. My responsibilities at this consulting firm included the duties and areas of expertise previously described, as well as management of projects and project teams working on behalf of utility clients.

I became a principal at Management Applications Consulting, ("MAC") at the time of its formation in May 1984. My experience at MAC included continued work in the electric and gas utility industry representing investor-owned utilities, electric cooperatives, and municipally-owned utility systems. My duties at MAC included the duties and areas of expertise described above. I remained a principal at MAC from May 1984 until January 2006.

From January 2006 through March 2007, I was employed as a management consultant by R. J. Covington Consulting, LLC. While employed by this firm, I continued to provide consulting services similar to those previously described as well as work in the areas of business valuation, affiliate transactions, and revenue requirement adjustments in regulatory proceedings.

In April 2007 I returned to MAC as a managing consultant. My responsibilities and job duties at MAC are the same as those previously described.

I have previously submitted testimony before the Public Service Commission of the State of Montana, the Public Utility Commission of Texas, the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Railroad Commission of Texas, the Public Service Commission of Wyoming, the North Carolina Utilities Commission, and the New Hampshire Public Utilities Commission. In addition, I have provided formal rate presentations to a number of municipally-owned and cooperative electric utilities. I am currently, or have in the past, been a member of the following organizations: Association of Energy Economics, Association of Energy Engineers, Association of Energy Services Professionals, American Statistical Association, NARUC Committee on Utility Billing Practices (past member), and the NARUC Ad Hoc Committee on Section I33 of PURPA (past member). During the past 34 years, I have made a number of presentations at various industry associations and trade groups.

Exhibit GLC-2

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER
SUMMARY OF RESOURCE ENERGY COSTS AND BASE FUEL FACTORS

LINE NO.	DESCRIPTION	TOTAL	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Base Resources				
2	Recoverable Fuel Costs	$76,185,028	$26,137,724	$24,643,426	$25,403,878
3	kWh Sales	2,282,789,101	784,700,545	738,282,902	759,805,654
4	Base Rate Fuel Factor	$0.033374	$0.033309	$0.033379	$0.033435
5					
6	Other Existing Resources				
7	Recoverable Fuel Costs	$24,347,239	$6,804,886	$8,455,486	$9,086,868
8	kWh Sales	318,474,678	90,679,515	108,755,098	119,040,065
9	Base Rate Fuel Factor	$0.076450	$0.075043	$0.077748	$0.076335
10					
11	Additional ARM Resources				
12	Recoverable Fuel Costs	$1,973,944	$0	$0	$1,973,944
13	kWh Sales	3,200,000	0	0	3,200,000
14	Base Rate Fuel Factor	$0.616857	$0.000000	$0.000000	$0.616857
15					
16	Total Resources				
17	Recoverable Fuel Costs	$102,506,211	$32,942,611	$33,098,912	$36,464,689
18	kWh Sales	2,604,463,779	875,380,060	847,038,000	882,045,719
19	Base Rate Fuel Factor	$0.039358	$0.037632	$0.039076	$0.041341

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER
RESOURCE ENERGY COSTS AND CREDITS - ALL RESOURCES

LINE NO.	DESCRIPTION	TOTAL	BASE RESOURCES	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	Resource Costs for Member Use	$67,096,874	$56,632,134	$10,464,740	$0
2	Plus:				
3	Resource Costs for Tariff Load	$19,329,841	$19,329,841	$0	$0
4	Resource Costs for Resource Transfers	2,844,341	1,145,169	1,699,172	0
5	Resource Costs of Third Party Sales	2,507,121	2,507,121	0	0
6	Resource Transfer Credits	(1,699,172)	(1,699,172)	0	0
7	Subtotal	$22,982,131	$21,282,959	$1,699,172	$0
8					
9	Total Resource Costs - Fuel Expense Accounts 501 and 547	$90,079,005	$77,915,093	$12,163,912	$0
10					
11	Plus:				
12	Purchased Power Account 555 - Demand	$4,066,417	$1,701,090	$0	$2,365,328
13	Purchased Power Account 555 - Energy	12,478,964	751,678	11,492,376	234,910
14	Subtotal	$16,545,381	$2,452,768	$11,492,376	$2,600,238
15					
16	Plus:				
17	Non-Firm Transmission of Electricity by Others Account 565	$2,880	$2,880	$0	$0
18	Firm Transmission of Electricity by Others Account 565	4,499,040	3,198,060	1,138,980	162,000
19	Subtotal	$4,501,921	$3,200,940	$1,138,980	$162,000
20					
21	Less:				
22	Firm Contract Revenues (Energy-Related)	($2,448,992)	($2,448,992)	$0	$0
23	Resource Economy Energy	(3,952,272)	(3,504,243)	(448,029)	0
24	Firm Contract Revenues (Demand-Related)	(1,430,539)	(1,430,539)	0	0
25	Scheduling Revenues	(788,294)	0	0	(788,294)
26	Subtotal	($8,620,097)	($7,383,774)	($448,029)	($788,294)
27					
28	Recoverable Resource Fuel Costs for FPPCA	$102,506,211	$76,185,028	$24,347,239	$1,973,944
29	Recoverable Resource Fuel Costs per kWh	$0.039358	$0.033374	$0.076450	$0.616857
30					
31	kWh Purchased by Class A Member by Resource Type	2,604,463,779	2,282,789,101	318,474,678	3,200,000

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF BASE RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	BASE RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Base Coal Costs for Member Use	$56,632,134	$19,467,093	$18,315,549	$18,849,492
2	Plus:				
3	Coal Costs for Tariff Load	$19,329,841	$6,678,640	$6,187,018	$6,464,183
4	Coal Costs for Resource Transfers	1,145,169	398,862	269,962	476,345
5	Coal Costs of Third Party Sales	2,507,121	1,199,603	705,665	601,853
6	Resource Transfer Credits	(1,699,172)	(572,118)	(405,130)	(721,924)
7	Subtotal	$21,282,959	$7,704,987	$6,757,515	$6,820,457
8					
9		$77,915,093	$27,172,080	$25,073,064	$25,669,949
10	Plus:				
11	Purchased Power Account 555 - Energy	$1,701,090	$584,744	$550,154	$566,192
12	Purchased Power Account 555 - Demand	751,678	269,101	238,282	244,295
13	Subtotal	$2,452,768	$853,844	$788,436	$810,488
14					
15	Plus:				
16	Non-Firm Transmission of Electricity by Others Account 565	2,880	990	932	959
17	Firm Transmission of Electricity by Others Account 565	3,198,060	1,144,905	1,013,785	1,039,369
18	Subtotal	$3,200,940	$1,145,896	$1,014,717	$1,040,328
19					
20	Total Fuel, Purchased Power and Wheeling Costs	$83,568,802	$29,171,819	$26,876,217	$27,520,765
21					
22	Less:				
23	Firm Contract Revenues (Energy-Related)	($2,448,992)	($841,832)	($792,035)	($815,125)
24	Base Resource Economy Energy	(3,504,243)	(1,680,130)	(987,275)	(836,838)
25	Firm Contract Revenues (Demand-Related	(1,430,539)	(512,133)	(453,481)	(464,925)
26	Subtotal	($7,383,774)	($3,034,095)	($2,232,791)	($2,116,888)
27					
28	Base Resource Recoverable Fuel Costs for FPPCA	$76,185,028	$26,137,724	$24,643,426	$25,403,878
29	Base Resource Recoverable Fuel Costs per kWh	$0.033374	$0.033309	$0.033379	$0.033435
30					
31	Base kWh Purchased by Class A Member	2,282,789,101	784,700,545	738,282,902	759,805,654
32	ACP Ratio	100.00%	35.80%	31.70%	32.50%

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF OTHER EXISTING RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	OTHER EXISTING RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Fuel Expense Account 547	$10,464,740	$2,979,633	$3,573,577	$3,911,530
2	Plus:				
3	Purchased Power Account 555 - Demand	0	0	0	0
4	Purchased Power Account 555 - Energy	11,492,376	3,272,232	3,924,502	4,295,642
5	Subtotal	$11,492,376	$3,272,232	$3,924,502	$4,295,642
6					
7	Plus:				
8	*Other Existing Resource Costs for Resource Transfers*	$1,699,172	$272,834	$749,346	$676,992
9					
10	Plus:				
11	Non-Firm Transmission of Electricity by Others Account 565	$0	$0	$0	$0
12	Firm Transmission of Electricity by Others Account 565	1,138,980	407,755	361,057	370,169
13	Subtotal	$1,138,980	$407,755	$361,057	$370,169
14					
15	Total Fuel, Purchased Power and Wheeling Costs	$24,795,268	$6,932,454	$8,608,482	$9,254,333
16					
17	Less:				
18	Firm Contract Revenues (Energy-Related)	$0	$0	$0	$0
19	OER Economy Energy	(448,029)	(127,568)	(152,996)	(167,465)
20	Subtotal	($448,029)	($127,568)	($152,996)	($167,465)
21					
22	Other Existing Resource Recoverable Fuel Costs for FPPCA	$24,347,239	$6,804,886	$8,455,486	$9,086,868
23	Other Existing Resource Recoverable Fuel Costs per kWh	$0.076450	$0.075043	$0.077748	$0.076335
24					
25	Other Resource kWh Purchased by Class A Member	318,474,678	90,679,515	108,755,098	119,040,065

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER
DEVELOPMENT OF ADDITIONAL ARM RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	ADDITIONAL ARM RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Purchased Power Account 555 - Demand	$2,365,328	$0	$0	$2,365,328
2	Purchased Power Account 555 - Energy	234,910	0	0	234,910
3	Subtotal	$2,600,238	$0	$0	$2,600,238
4					
5	Plus:				
6	Non-Firm Transmission of Electricity by Others Account 565	$0	$0	$0	$0
7	Firm Transmission of Electricity by Others Account 565	162,000	0	0	$162,000
8	Subtotal	$162,000	$0	$0	$162,000
9					
10	Total Fuel, Purchased Power and Wheeling Costs	$2,762,238	$0	$0	$2,762,238
11					
12	Less:				
13	Firm Contract Revenues (Energy-Related)	$0	$0	$0	0
14	Additional ARM Economy Energy	0	0	0	0
15	Scheduling Revenues	(788,294)	0	0	(788,294)
16	Subtotal	($788,294)	$0	$0	($788,294)
17					
18	Additional ARM Resource Recoverable Fuel Costs for FPPCA	$1,973,944	$0	$0	$1,973,944
19	Additional Resource Recoverable Fuel Costs per kWh	$0.616857	$0.000000	$0.000000	$0.616857
20					
21	Additional ARM kWh Purchased by Class A Member	3,200,000	0	0	3,200,000

Arizona Electric Power Cooperative, Inc.
P.O. Box 670 • Benson, Arizona 85602-0670 • Phone 520-586-3631

BEFORE THE ARIZONA CORPORATION COMMISSION

A.A.C. R14-2-103.B SCHEDULES

IN SUPPORT OF

THE ARIZONA ELECTRIC POWER COOPERATIVE, INC.

RATE APPLICATION

DOCKET NO. E-01773A

OCTOBER 2009

A Touchstone Energy® Cooperative

Arizona Electric Power Cooperative, Inc.
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Arizona Electric Power Cooperative, Inc.
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A

Arizona Electric Power Cooperative, Inc.

SCHEDULE A-1

10/1/2009

Computation of Increase in Gross Revenue Requirements
Test Year End 3/31/2009

LINE NO.		ORIGINAL COST	
1.	ADJUSTED RATE BASE	$ 231,844,975	(a)
2.	ADJUSTED ELECTRIC OPERATING INCOME (MARGINS)	11,334,942	(b)
3.	CURRENT RATE OF RETURN	4.89%	
4.	REQUIRED ELECTRIC OPERATING INCOME (MARGINS)	15,357,962	(c)
5.	REQUIRED RATE OF RETURN	6.62%	
6.	OPERATING INCOME DEFICIENCY	$ 4,023,020	
7.	INCREASE (decrease) IN GROSS REV. REQUIREMENTS	$ 4,023,020	

	CUSTOMER CLASSIFICATION	PROJECTED REVENUE INC. DUE TO RATES	% DOLLAR INCREASE
		(d)	(d)
8.	MEMBER CONTRACTS (ALL AND PARTIAL REQUIREMENTS)	$ 4,023,020	2.41%
9.	OTHER FIRM CONTRACTS (PARTIAL REQ.)	-	-
10.	TOTAL	$ 4,023,020	2.41%

SUPPORTING SCHEDULES:
(a) B-1, LINE 9
(b) A-2, LINE 3
(c) G-2, LINE 9
(d) H-1

Arizona Electric Power Cooperative, Inc.

Summary Results of Operations

SCHEDULE A-2
10/1/2009

LINE NO.		-PRIOR YEARS- 3/31/2007 (a)	3/31/2008 (a)	3/31/2009 TEST YEAR ACTUAL (a)	TEST YEAR ADJUSTED (b)	PROPOSED RATES (c)
1.	GROSS REVENUE	$ 195,971,975	$ 219,877,845	$ 209,981,784	$ 178,762,679	$ 182,785,699
2.	OPERATING EXPENSES	169,498,279	188,992,808	183,767,165	167,427,737	167,427,737
3.	ELECTRIC OPERATING INCOME (MARGINS)	26,473,696	30,885,037	26,214,619	11,334,942	15,357,962
4.	TOTAL INTEREST & OTHER DEDUCTIONS	13,150,255	11,297,983	11,325,919	11,917,826	11,917,826
5.	TOTAL OTHER NON OPERATING INCOME	1,367,120	1,824,300	945,315	1,112,155	1,112,155
5a.	EXTRAORDINARY ITEMS	-	-	-	-	-
6.	NET INCOME (MARGINS)	$ 14,690,561	$ 21,411,354	$ 15,834,015	$ 529,271	$ 4,552,291
7.	THROUGH 14.	NOT APPLICABLE				
15.	TIMES TOTAL INTEREST EARNED (TIER)	2.20	2.96	2.50	1.05	1.42
16.	DEBT SERVICE COVERAGE (DSC)	1.19	1.41	1.39	1.12	1.35

SUPPORTING SCHEDULES:
(a) E-2, PAGES 1 & 2
(b) C-1, PAGES 3 & 4
(c) F-1, PAGES 1 & 2

Arizona Electric Power Cooperative, Inc.

Summary of Capital Structure

SCHEDULE A-3
10/1/2009

LINE NO.	DESCRIPTION	PRIOR YEARS 3/31/2007	PRIOR YEARS 3/31/2008 (a)	ACTUAL TEST YEAR 3/31/2009 (c)	END OF PROJECTED YR 3/31/2010 (c)
1.	SHORT-TERM DEBT	$15,017,463	$24,771,128	$15,851,384	$15,851,384
2.	LONG-TERM DEBT	185,683,757	161,746,607	178,093,188	192,789,771
3.	TOTAL DEBT (a)	200,701,220	186,517,735	193,944,572	208,641,155
4.	PREFERRED STOCK	-	-	-	-
5.	MARGINS AND EQUITY (b)	27,423,893	60,032,833	75,866,848	64,585,124
6.	TOTAL CAPITAL	$ 228,125,113	$ 246,550,568	$ 269,811,420	$ 273,226,279
	CAPITALIZATION RATIOS: (%)				
7.	SHORT-TERM DEBT	6.58%	10.05%	5.87%	5.80%
8.	LONG-TERM DEBT	81.40%	65.60%	66.01%	70.56%
9.	TOTAL DEBT	87.98%	75.65%	71.88%	76.36%
10.	PREFERRED STOCK	0.00%	0.00%	0.00%	0.00%
11.	MARGINS AND EQUITY	12.02%	24.35%	28.12%	23.64%
		100.00%	100.00%	100.00%	100.00%
12.	WEIGHTED COST OF SHORT TERM DEBT	5.15%	7.15%	4.25%	4.25%
13.	WEIGHTED COST OF LONG TERM DEBT	6.24%	6.06%	6.07%	5.72%
14.	WEIGHTED COST OF SENIOR CAPITAL	NOT APPLICABLE			

SUPPORTING SCHEDULES:
(a) D-2
(b) E-1, PAGE 2 LINE 25
(c) D-1

Arizona Electric Power Cooperative, Inc.

Construction Expenditures and Gross Utility Plant in Service

SCHEDULE A-4
10/1/2009

LINE NO.			CONSTRUCTION EXPENDITURES			NET PLANT ADDITIONS			GROSS UTILITY PLANT IN SERVICE	
1.	3/31/2007	$	9,434,638	(a)	$	(1,249,588)		$	400,661,362	(d)
2.	3/31/2008		7,467,384	(a)		7,090,728			393,570,634	(c)
3.	3/31/2009		25,616,852	(a)		5,853,730	(c)		399,424,364	(c)
4.	3/31/2010		20,113,770	(b)		23,593,561			423,017,925	
5.	3/31/2011		35,295,070	(b)		20,113,770			443,131,695	
6.	3/31/2012		29,718,927	(b)		35,295,070			478,426,765	

SUPPORTING SCHEDULES:
(a) E-3, LINE 15
(b) F-3, LINE 6
(c) E-5, PAGE 2, LINE 39
(d) E-1, PAGE 1, LINE 1

Arizona Electric Power Cooperative, Inc.
Summary of Changes in Financial Position

LINE NO.		-PRIOR YEARS (a)- 3/31/2007	3/31/2008	ACTUAL TEST YEAR	12 MOS. ENDED 3/31/2009 PRESENT RATES (b)	PROPOSED RATES (b)
1.	NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 28,643,154	$ 22,381,804	$ 13,616,330	$ 905,169	$ 4,928,189
2.	NET CASH USED IN INVESTING ACTIVITIES	(10,394,683)	(5,424,406)	(29,201,380)	(29,201,380)	(29,201,380)
3.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(17,084,007)	(12,893,380)	7,972,352	7,972,352	7,972,352
4.	NET DECREASE IN CASH AND CASH EQ.	$ 1,164,464	$ 4,064,018	$ (7,612,698)	$ (20,323,859)	$ (16,300,839)

SUPPORTING SCHEDULES:
(a) E-3
(b) F-2

B

Arizona Electric Power Cooperative, Inc.

Summary of Original Cost Rate Base

SCHEDULE B-1

10/1/2009

LINE NO.		ORIGINAL COST RATE BASE*	
1.	GROSS UTILITY PLANT IN SERVICE	$ 399,424,364	(a)
2.	LESS: ACCUMULATED DEPRECIATION & AMORT.	(204,796,249)	(a)
3.	NET UTILITY PLANT IN SERVICE	$ 194,628,115	(a)
	LESS:		
4.	CUSTOMER ADVANCES FOR CONSTRUCTION	-	
5.	CONTRIBUTION IN AID OF CONSTRUCTION	-	
6.	ADD: ALLOWANCE FOR WORKING CAPITAL	21,814,465	(b)
7.	PLANT HELD FOR FUTURE USE	2,551,631	(c)
8.	DEFERRED DEBITS	12,850,764	(d)
9.	TOTAL RATE BASE	$ 231,844,975	(e)

*** INCLUDING PRO FORMA ADJUSTMENTS**

SUPPORTING SCHEDULES:
(a) B-2 LINES 10, 13, & 14
(b) B-5, PAGE 1
(c) E-5, PAGE 2
(d) E-1, PAGE 1

RECAP SCHEDULES:
(e) A-1

Arizona Electric Power Cooperative, Inc.
Original Cost Rate Base Pro Forma Adjustments

SCHEDULE B-2
10/1/2009

LINE NO.		ACTUAL TEST YEAR 3/31/2009 (a)	PRO FORMA ADJUSTMENTS 3/31/2009 (a)	ADJUSTED TEST YEAR 3/31/2009	
	PRODUCTION:				
1.	GROSS PLANT	$ 370,911,555	$ -	$ 370,911,555	
2.	ACCUMULATED DEPRECIATION	(194,303,265)	-	(194,303,265)	
3.	NET PLANT	176,608,290	-	176,608,290	
	TRANSMISSION:				
4.	GROSS PLANT	2,889,491	-	2,889,491	
5.	ACCUMULATED DEPRECIATION	(1,580,842)	-	(1,580,842)	
6.	NET PLANT	1,308,649	-	1,308,649	
	GENERAL & INTANGIBLE:				
7.	GROSS PLANT	25,623,318	-	25,623,318	
8.	ACCUMULATED DEPRECIATION	(10,016,425)	-	(10,016,425)	
9.	NET PLANT	15,606,893	-	15,606,893	
9A.	RWIP	3,547,307	-	3,547,307	
10.	TOTAL GROSS PLANT	399,424,364	-	399,424,364	(b)
11.	TOTAL ACC DEP. & RWIP	(202,353,225)	-	(202,353,225)	
12.	ACCUMULATED AMORTIZATION	(2,443,024)	-	(2,443,024)	
13.	TOTAL ACCUM DEPREC. & AMORT.	(204,796,249)	-	(204,796,249)	(b)
14.	TOTAL NET PLANT	$ 194,628,115	$ -	$ 194,628,115	(b)

SUPPORTING SCHEDULES:
(a) E-5, PAGES 1 AND 2

RECAP SCHEDULES:
(b) B-1, LINES 1, 2, & 3

Arizona Electric Power Cooperative, Inc.

RCND Rate Base Pro Forma Adjustments

SCHEDULE B-3
10/1/2009

LINE NO.		ACTUAL AT TEST YEAR 3/31/2009	PRO FORMA ADJUSTMENTS 3/31/2009	ADJUSTED TEST YEAR 3/31/2009
1.	GROSS UTILITY PLANT IN SERVICE	$ -	$ -	$ -
2.	LESS: ACCUMULATED DEPRECIATION	-	-	-
3.	NET UTILITY PLANT IN SERVICE	$ -	$ -	$ -

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

Arizona Electric Power Cooperative, Inc.
RCND by Major Plant Accounts

LINE NO.		RCN	DEPR.	RCND	PRO FORMA ADJUST.	ADJUSTED RCND
	INTANGIBLE PLANT:					
1.	301ORGANIZATION	$ -	$ -	$ -	$ -	$ -
2.	114 ACQUISITION ADJUSTMENT	-	-	-	-	-
3.	302 FRANCHISE ADJUSTMENT	-	-	-	-	-
4.	SUBTOTAL INTANGIBLE	-	-	-	-	-
	STEAM PRODUCTION PLANT:					
5.	310 LAND AND LAND RIGHTS	-	-	-	-	-
6.	311 STRUCTURES AND IMPROVEMENTS	-	-	-	-	-
7.	312 BOILER EQUIPMENT	-	-	-	-	-
8.	314 TURBINE GENERATORS	-	-	-	-	-
9.	315 ACCESSORY ELEC. EQUIPMEN	-	-	-	-	-
10.	316 MISC. POWER EQUIPMENT	-	-	-	-	-
11.	SUBTOTAL STEAM PRODUCTION	-	-	-	-	-
	OTHER PRODUCTION PLANT:					
12.	340 LAND AND LAND RIGHTS	-	-	-	-	-
13.	341 STRUCTURES AND IMPROVEMENTS	-	-	-	-	-
14.	342 FUEL HLDRS PRODRS & ACCE	-	-	-	-	-
15.	343 PRIME MOVERS	-	-	-	-	-
16.	344 GENERATORS	-	-	-	-	-
17.	345 ACCESSORY ELEC. EQUIPMENT	-	-	-	-	-
18.	346 MISC. POWER EQUIPMENT	-	-	-	-	-
19.	SUBTOTAL OTHER PRODUCTION	-	-	-	-	-
	TRANSMISSION PLANT:					
20.	350 LAND AND LAND RIGHTS	-	-	-	-	-
21.	352 STRUCTURES AND IMPRVMNT	-	-	-	-	-
22.	353 STATION EQUIPMENT	-	-	-	-	-
23.	354 TOWERS AND FIXTURES	-	-	-	-	-
24.	355 POLES AND FIXTURES	-	-	-	-	-
25	356 OVERHEAD CONDUCTORS	-	-	-	-	-
26.	359 ROADS AND TRAILS	-	-	-	-	-
27.	SUBTOTAL TRANSMISSION	-	-	-	-	-
	GENERAL PLANT:					
28.	309 LAND AND LAND RIGHTS	-	-	-	-	-
29.	390 ACCOUNTS 390 - 399	-	-	-	-	-
30.	SUBTOTAL GENERAL	-	-	-	-	-
31.	TOTAL	$ -	$ -	$ -	$ -	$ -

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

Arizona Electric Power Cooperative, Inc.

RCND by Major Plant Accounts

LINE NO.		ADJ. 1	ADJ. 2	ADJ. 3	ADJ. 4	TOTAL ADJUSMENTS
	INTANGIBLE PLANT:					
1.	301 ORGANIZATION	$ -	$ -	$ -	$ -	$ -
2.	114 ACQUISITION ADJUSTMENT	-	-	-	-	-
3.	302 FRANCHISE ADJUSTMENT	-	-	-	-	-
4.	SUBTOTAL INTANGIBLE	-	-	-	-	-
	STEAM PRODUCTION PLANT:					
5.	310 LAND AND LAND RIGHTS	-	-	-	-	-
6.	311 STRUCTURES AND IMPROVEMEN	-	-	-	-	-
7.	312 BOILER EQUIPMENT	-	-	-	-	-
8.	314 TURBINE GENERATORS	-	-	-	-	-
9.	315 ACCESSORY ELEC. EQUIPMENT	-	-	-	-	-
10.	316 MISC. POWER EQUIPMENT	-	-	-	-	-
11.	SUBTOTAL STEAM PRODUCTION	-	-	-	-	-
	OTHER PRODUCTION PLANT:					
12.	340 LAND AND LAND RIGHTS	-	-	-	-	-
13.	341 STRUCTURES AND IMPROVEMEN	-	-	-	-	-
14.	342 FUEL HLDRS PRODCRS & ACC	-	-	-	-	-
15.	343 PRIME MOVERS	-	-	-	-	-
16.	344 GENERATORS	-	-	-	-	-
17.	345 ACCESSORY ELEC. EQUIPMENT	-	-	-	-	-
18.	346 MISC. POWER EQUIPMENT	-	-	-	-	-
19.	SUBTOTAL OTHER PRODUCTION	-	-	-	-	-
	TRANSMISSION PLANT:					
20.	350 LAND AND LAND RIGHTS	-	-	-	-	-
21.	352 STRUCTURES AND IMPROVEMEN	-	-	-	-	-
22.	353 STATION EQUIPMENT	-	-	-	-	-
23.	354 TOWERS AND FIXTURES	-	-	-	-	-
24.	355 POLES AND FIXTURES	-	-	-	-	-
25.	356 OVERHEAD CONDUCTORS	-	-	-	-	-
26.	359 ROADS AND TRAILS	-	-	-	-	-
27.	SUBTOTAL TRANSMISSION	-	-	-	-	-
	GENERAL PLANT:					
28.	389 LAND AND LAND RIGHTS	-	-	-	-	-
29.	390 ACCOUNTS 390 - 399	-	-	-	-	-
30.	SUBTOTAL GENERAL	-	-	-	-	-
31.	TOTAL	$ -	$ -	$ -	$ -	$ -

RECAPSCHEDULES:

Arizona Electric Power Cooperative, Inc.
Computation of Working Capital

LINE NO.			
1.	CASH WORKING CAPITAL	$ -	(a)
2.	FUEL STOCK	16,033,459	(b)
3.	MATERIALS AND SUPPLIES	5,781,006	(c)
4.	PREPAYMENTS	0	(d)
5	TOTAL WORKING CAPITAL	$ 21,814,465	(e)

SUPPORTING SCHEDULES:
(a) B-5, PAGE 2
(b) B-5, PAGE 3
(c) B-5, PAGE 4
(d) B-5, PAGE 5

RECAP SCHEDULES:
(e) B-1, Line 6

Arizona Electric Power Cooperative, Inc.

Calculation of Cash Working Capital

LINE NO.			
1.	TOTAL PRO FORMA O&M EXPENSES EXCL PRO FORMA FUEL & OTHER EXP	$	-
	NET OTHER O&M EXPENSE LAG		
2.	A. DAYS		-
3.	B. PERCENT	0.00%	
4.	CASH WORKING CAPITAL OTHER THAN FUEL		-
5.	FUEL EXPENSE		-
	FUEL EXPENSE LAG:		
6.	A. LAG IN REVENUES (DAYS)		-
7.	B. LAG IN EXPENSES (DAYS)		-
8.	C. NET LAG -DAYS		-
9.	D. PERCENT	0.00%	
10.	CASH WORKING CAPITAL FUEL		-
11.	TOTAL CASH WORKING CAPITAL	$	-

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

Arizona Electric Power Cooperative, Inc.
Calculation of Fuel-Stock Working Capital

LINE NO.		PER BOOKS	AS ADJUSTED	
1.	APRIL	$ 12,947,499	$ 12,947,499	
2.	MAY	13,052,341	13,052,341	
3.	JUNE	12,202,455	12,202,455	
4.	JULY	13,487,043	13,487,043	
5.	AUGUST	13,527,247	13,527,247	
6.	SEPTEMBER	13,493,843	13,493,843	
7.	OCTOBER	11,817,432	11,817,432	
8.	NOVEMBER	17,387,542	17,387,542	
9.	DECEMBER	19,099,253	19,099,253	
10.	JANUARY	19,592,846	19,592,846	
11.	FEBRUARY	20,512,638	20,512,638	
12.	MARCH	25,281,374	25,281,374	
13.	TOTAL	$ 192,401,513	$ 192,401,513	
14.	12-MONTH AVERAGE		$ 16,033,459	(a)

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) B-5, PAGE 1

Arizona Electric Power Cooperative, Inc.

Calculation of Materials & Supplies Working Capital

LINE NO.		PER BOOKS	AS ADJUSTED	
1.	MARCH (Prior Yr)	$ 5,477,444		
2.	APRIL	5,472,079	$ 5,474,761	
3.	MAY	5,617,091	5,544,585	
4.	JUNE	5,761,128	5,689,109	
5.	JULY	5,738,710	5,749,919	
6.	AUGUST	5,860,779	5,799,745	
7.	SEPTEMBER	5,885,008	5,872,893	
8.	OCTOBER	5,833,455	5,859,231	
9.	NOVEMBER	5,859,314	5,846,385	
10.	DECEMBER	5,907,983	5,883,648	
11.	JANUARY	5,923,451	5,915,717	
12.	FEBRUARY	5,977,342	5,950,396	
13.	MARCH	5,594,033	5,785,688	
14.	TOTAL	$ 69,430,373	$ 69,372,078	
15.	12-MONTH AVERAGE		$ 5,781,006	(a)

SUPPORTING SCHEDULES:

RECAP SCHEDULE:
(a) B-5, PAGE 1

Arizona Electric Power Cooperative, Inc.

Calculation of Prepayments Working Capital

LINE NO.		PER BOOKS	PRO FORMA ADJUSTMENTS	AS ADJUSTED
1.	MARCH (Prior Yr)	$ -	$ -	$ -
2.	APRIL	-	-	-
3.	MAY	-	-	-
4.	JUNE	-	-	-
5.	JULY	-	-	-
6.	AUGUST	-	-	-
7.	SEPTEMBER	-	-	-
8.	OCTOBER	-	-	-
9.	NOVEMBER	-	-	-
10.	DECEMBER	-	-	-
11.	JANUARY	-	-	-
12.	FEBRUARY	-	-	-
13.	MARCH	-	-	-
14.	TOTAL	$0	$ -	$0
15.	13-MONTH AVERAGE	$0	$ -	$0 (a)

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) B-5, PAGE 1

C

Arizona Electric Power Cooperative, Inc.

Reclassified Year End Income Statement

LINE NO.		PER BOOKS 3/31/2009 (a) (c)	RECLASSIFIED ADJUST. (b)	RECL TEST YR 3/31/2009
	REVENUES:			
1.	CLASS A MEMBERS	$ 112,717,749	$ (247,456)	$ 112,470,293
2.	FUEL ADJUSTMENT	35,644,363	-	35,644,363
3.	NON-CLS A, NON-FIRM & NON-MEM	48,834,238	-	48,834,238
4.	TOTAL ELECTRIC REVENUE:	197,196,350	(247,456)	196,948,894
5.	OTHER OPERATING REVENUE	12,785,434	(9,261,491)	3,523,943
6.	TOTAL OPERATING REVENUE	209,981,784	(9,508,947)	200,472,837
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	72,540,278	(551,375)	71,988,903
8.	PRODUCTION - STEAM A/C 500	5,997,229	-	5,997,229
9.	A/C 502	2,795,766	(1,708,100)	1,087,666
10.	A/C 503	-	-	-
11.	A/C 504	-	-	-
12.	A/C 505	1,385,698	(509,412)	876,286
13.	A/C 506 & 509	1,083,857	-	1,083,857
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	234,983	-	234,983
17.	A/C 548	707,145	(509,363)	197,782
18.	A/C 549	39,148	-	39,148
19.	A/C 550	-	-	-
	OTHER POWER SUPPLY			
20.	DEMAND A/C 555	6,274,506	-	6,274,506
21.	ENERGY A/C 555	35,795,430	-	35,795,430
22.	A/C 556	3,315,542	(833,446)	2,482,096
23.	A/C 557	1,548,021	(1,548,021)	-
24.	TRANSMISSION	16,345,977	(6,880,024)	9,465,953
25.	ADMINISTRATIVE & GENERAL	11,249,966	264,291	11,514,257
26.	TOTAL OPERATIONS	159,313,546	(12,275,450)	147,038,096
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	1,302,263	-	1,302,263
28.	A/C 511	26,944	-	26,944
29.	A/C 512	4,763,936	-	4,763,936
30.	A/C 513	6,184,656	-	6,184,656
31.	A/C 514	2,334,541	-	2,334,541
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	51,049	-	51,049
34.	A/C 552	27,641	-	27,641
35.	A/C 553	1,384,550	-	1,384,550
36.	A/C 554	175,654	-	175,654
37.	TRANSMISSION	13,624	-	13,624
38.	GENERAL PLANT	304,878	-	304,878
39.	TOTAL MAINTENANCE	16,569,736	-	16,569,736

Arizona Electric Power Cooperative, Inc.
Reclassified Year End Income Statement

LINE NO.		PER BOOKS 3/31/2009 (a) (c)	RECLASSIFIED ADJUST. (b)	RECL TEST YR 3/31/2009
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	7,883,883	-	7,883,883
41.	ACC GROSS REVENUE TAXES	-	-	-
42.	TAXES	-	2,933,343	2,933,343
43.	TOTAL OTHER	7,883,883	2,933,343	10,817,226
44.	TOTAL OPERATING EXPENSES	183,767,165	(9,342,107)	174,425,058
45.	ELECTRIC OPERATING MARGINS	26,214,619	(166,840)	26,047,779
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	10,580,757	-	10,580,757
47.	INTEREST CHARGES TO CONSTR	(187,816)	-	(187,816)
48.	OTHER INTEREST EXPENSE	781,804	-	781,804
49.	OTHER DEDUCTIONS	151,174	-	151,174
50.	TOTAL INTEREST & OTHER DEDUCTIONS	11,325,919	-	11,325,919
51.	OPERATING MARGINS	14,888,700	(166,840)	14,721,860
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	546,419	-	546,419
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	398,896	166,840	565,736
55.	TOTAL OTHER NON OPERATING INCOME	945,315	166,840	1,112,155
55a.	EXTRAORDINARY ITEMS	-	-	-
56.	NET INCOME (MARGINS)	15,834,015	-	15,834,015

SUPPORTING SCHEDULES:
(a) RUS FORM 12A
(b) C-2, PAGES 1 & 2

RECAP SCHEDULE:
(c) A-2

Arizona Electric Power Cooperative, Inc.
Adjusted Year End Income Statement

LINE NO.		RECL TEST YR 3/31/2009 (c)	PRO FORMA ADJUST. (a)	ADJ TEST YR 3/31/2009 (b)
	REVENUES:			
1.	CLASS A MEMBERS	$ 112,470,293	$ 12,729,054	$ 125,199,347
2.	FUEL ADJUSTMENT	35,644,363	5,774,929	41,419,292
3.	NON-CLS A, NON-FIRM & NON-MEM	48,834,238	(40,214,141)	8,620,097
4.	TOTAL ELECTRIC REVENUE:	196,948,894	(21,710,158)	175,238,736
5.	OTHER OPERATING REVENUE	3,523,943	-	3,523,943
6.	TOTAL OPERATING REVENUE	200,472,837	(21,710,158)	178,762,679
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	71,988,903	16,520,095	88,508,998
8.	PRODUCTION - STEAM A/C 500	5,997,229	354,307	6,351,536
9.	A/C 502	1,087,666	2,839,932	3,927,598
10.	A/C 503	-	-	-
11.	A/C 504	-	-	-
12.	A/C 505	876,286	-	876,286
13.	A/C 506 & 509	1,083,857	20,818	1,104,675
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	234,983	13,891	248,874
17.	A/C 548	197,782	1,405	199,187
18.	A/C 549	39,148	816	39,964
19.	A/C 550	-	-	-
	OTHER POWER SUPPLY			
20.	- DEMAND A/C 555	6,274,506	(3,157,500)	3,117,006
21.	- ENERGY A/C 555	35,795,430	(22,367,055)	13,428,375
22.	A/C 556	2,482,096	109,150	2,591,246
23.	A/C 557	-	-	-
24.	TRANSMISSION	9,465,953	(4,963,137)	4,502,816
25.	ADMINISTRATIVE & GENERAL	11,514,257	540,635	12,054,892
26.	TOTAL OPERATIONS	147,038,096	(10,086,643)	136,951,453
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	1,302,263	85,151	1,387,414
28.	A/C 511	26,944	1,342	28,286
29.	A/C 512	4,763,936	(680,227)	4,083,709
30.	A/C 513	6,184,656	(533,229)	5,651,427
31.	A/C 514	2,334,541	105,664	2,440,205
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	51,049	3,337	54,386
34.	A/C 552	27,641	3,164,043	3,191,684
35.	A/C 553	1,384,550	376,795	1,761,345
36.	A/C 554	175,654	6,042	181,696
37.	TRANSMISSION	13,624	526	14,150
38.	GENERAL PLANT	304,878	95,593	400,471
39.	TOTAL MAINTENANCE	16,569,736	2,625,037	19,194,773

Arizona Electric Power Cooperative, Inc.
Adjusted Year End Income Statement

LINE NO.		RECL TEST YR 3/31/2009 (c)	PRO FORMA ADJUST. (a)	ADJ TEST YR 3/31/2009 (b)
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 7,883,883	$ 464,285	$ 8,348,168
41.	ACC GROSS REVENUE TAXES	-	-	-
42.	TAXES	2,933,343	-	2,933,343
43.	TOTAL OTHER	10,817,226	464,285	11,281,511
44.	TOTAL OPERATING EXPENSES	174,425,058	(6,997,321)	167,427,737
45.	ELECTRIC OPERATING MARGINS	26,047,779	(14,712,837)	11,334,942
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	10,580,757	231,437	10,812,194
47.	INTEREST CHARGES TO CONSTRUCTION	(187,816)	-	(187,816)
48.	OTHER INTEREST EXPENSE	781,804	360,470	1,142,274
49.	OTHER DEDUCTIONS	151,174	-	151,174
50.	TOTAL INTEREST & OTHER DEDUCTIONS	11,325,919	591,907	11,917,826
51.	OPERATING MARGINS	14,721,860	(15,304,744)	(582,884)
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	546,419	-	546,419
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	565,736	-	565,736
55.	TOTAL OTHER NON OPERATING INCOME	1,112,155	-	1,112,155
55a.	EXTRAORDINARY ITEMS	-	-	-
56.	NET INCOME (MARGINS)	$ 15,834,015	(15,304,744)	529,271

SUPPORTING SCHEDULES:
(a) C-2 PAGES 3 - 10

RECAP SCHEDULE:
(b) A-2
(c) C-1 PAGES 1 & 2

Arizona Electric Power Cooperative, Inc.
Income Statement Reclassification Adjustments

LINE NO.	(a)	1 SWTC REVENUE RECLASS.	2 ACC GOR ASSESSMENT	3 COAL LEGAL EXPENSES	4 PROPERTY TAX RECLASS.	4 TOTAL RECLASS.
	REVENUES:					
1.	CLASS A MEMBERS	$ -	$ (247,456)	$ -	$ -	$ (247,456)
2.	FUEL ADJUSTMENT	-		-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	-		-	-	-
4.	TOTAL ELECTRIC	-	(247,456)	-	-	(247,456)
5.	OTHER OPERATING REVENUE	(9,261,491)		-	-	(9,261,491)
6.	TOTAL OPERATING REVENUE	(9,261,491)	(247,456)	-	-	(9,508,947)
	OPERATING EXPENSES:					
	OPERATIONS					
7.	PRODUCTION -FUEL A/C 501 & 547	-		(538,144)	(13,231)	(551,375)
8.	PRODUCTION - STEAM A/C 500	-		-	-	-
9.	A/C 502	-		-	(1,708,100)	(1,708,100)
10.	A/C 503	-		-	-	-
11.	A/C 504	-		-	-	-
12.	A/C 505	-		-	(509,412)	(509,412)
13.	A/C 506 & 509	-		-	-	-
14.	A/C 507	-		-	-	-
15.	A/C 508	-		-	-	-
16.	PRODUCTION - OTHER - A/C 546	-		-	-	-
17.	A/C 548	-		-	(509,363)	(509,363)
18.	A/C 549	-		-	-	-
19.	A/C 550	-		-	-	-
	OTHER POWER SUPPLY					
20.	- DEMAND A/C 555	-		-	-	-
21.	- ENERGY A/C 555	-		-	-	-
22.	A/C 556	(833,446)		-	-	(833,446)
23.	A/C 557	(1,548,021)		-	-	(1,548,021)
24.	TRANSMISSION	(6,880,024)		-	-	(6,880,024)
25.	ADMINISTRATIVE & GENERAL	-	(247,456)	538,144	(26,397)	264,291
26.	TOTAL OPERATIONS	(9,261,491)	(247,456)	-	(2,766,503)	(12,275,450)
	MAINTENANCE					
27.	PRODUCTION - STEAM - A/C 510	-		-	-	-
28.	A/C 511	-		-	-	-
29.	A/C 512			-	-	-
30.	A/C 513	-		-	-	-
31.	A/C 514	-		-	-	-
32.	A/C 515	-		-	-	-
33.	PRODUCTION - OTHER - A/C 551	-		-	-	-
34.	A/C 552	-		-	-	-
35.	A/C 553	-		-	-	-
36.	A/C 554	-		-	-	-
37.	TRANSMISSION	-		-	-	-
38.	GENERAL PLANT	-		-	-	-
39.	TOTAL MAINTENANCE	-		-	-	-

Arizona Electric Power Cooperative, Inc.

Income Statement Reclassification Adjustments

LINE NO.	(a)	1 SWTC REVENUE RECLASS	2 ACC GOR ASSESSMENT	3 COAL LEGAL EXPENSES	4 MEC SCHEDULE B RECLASS	TOTAL RECLASS
	OTHER:					
40.	DEPRECIATION & AMORTIZATION	$ -		$ -	$ -	$ -
41.	ACC GROSS REVENUE TAXES	-		-	-	-
42.	TAXES	-		-	2,933,343	2,933,343
43.	TOTAL OTHER	-		-	2,933,343	2,933,343
44.	TOTAL OPERATING EXPENSES	(9,261,491)	(247,456)	-	166,840	(9,342,107)
45.	ELECTRIC OPERATING MARGINS	-		-	(166,840)	(166,840)
	INTEREST & OTHER DEDUCTIONS:					
46.	INTEREST ON LONG-TERM DEBT	-		-	-	-
47.	INTEREST CHARGES TO CONSTR	-		-	-	-
48.	OTHER INTEREST EXPENSE	-		-	-	-
49.	OTHER DEDUCTIONS	-		-	-	-
50.	TOTAL INTEREST & OTHER DEDUCTIONS	-	-	-	-	-
51.	OPERATING MARGINS	-	-	-	(166,840)	(166,840)
	OTHER NON OPERATING INCOME:					
52.	INTEREST INCOME	-	-	-	-	-
53.	AFUDC	-	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	166,840	166,840
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	166,840	166,840
55a.	EXTRAORDINARY ITEMS	-	-	-	-	-
56.	NET INCOME (MARGINS)	$ -	$ -	$ -	$ -	$ -

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) C-1,PAGES 1 AND 2

Arizona Electric Power Cooperative, Inc.

Income Statement Pro-Forma Adjustments

LINE NO.		1 COAL COST ADJUSTMENT	2 PAYROLL & PENSION ADJUSTMENTS	3 SRP CONTRACT EXPIRATION ADJUSTMENT	4 CITY OF MESA CONTRACT EXPIR. ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ -	$ -
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	8,639,944	-	(42,873,982)	(5,980,103)
4.	TOTAL ELECTRIC	8,639,944	-	(42,873,982)	(5,980,103)
5.	OTHER OPERATING REVENUE	-	-	-	-
6.	TOTAL OPERATING REVENUE	8,639,944	-	(42,873,982)	(5,980,103)
	OPERATING EXPENSES: OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	23,586,639	59,915	(25,209,256)	(3,200,162)
8.	PRODUCTION - STEAM A/C 500	-	354,307	-	-
9.	A/C 502	-	35,856	-	-
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	-	-	-
13.	A/C 506 & 509	-	20,818	-	-
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	13,891	-	-
17.	A/C 548	-	1,405	-	-
18.	A/C 549	-	816	-	-
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				
20.	- DEMAND A/C 555	-	-	-	-
21.	- ENERGY A/C 555	-		-	-
22.	A/C 556	-	109,150	-	-
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	-		(4,454,400)	(508,737)
25.	ADMINISTRATIVE & GENERAL	-	380,635	-	-
26.	TOTAL OPERATIONS	23,586,639	976,793	(29,663,656)	(3,708,899)
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	85,151	-	-
28.	A/C 511	-	1,342	-	-
29.	A/C 512	-	138,123	-	-
30.	A/C 513	-	27,815	-	-
31.	A/C 514	-	105,664	-	-
32.	A/C 515	-	-	-	-
33.	PRODUCTION - OTHER - A/C 551	-	3,337	-	-
34.	A/C 552	-	1,543	-	-
35.	A/C 553	-	30,603	-	-
36.	A/C 554	-	6,042	-	-
37.	TRANSMISSION	-	526	-	-
38.	GENERAL PLANT	-	95,593	-	-
39.	TOTAL MAINTENANCE	-	495,739	-	-

Arizona Electric Power Cooperative, Inc.
Income Statement Pro Forma Adjustments

LINE NO.		1 COAL PRICE ADJUSTMENT	2 PAYROLL & PENSION ADJUSTMENTS	3 SRP CONTRACT EXPIRATION ADJUSTMENT	4 CITY OF MESA CONTRACT EXPIR. ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ -
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	-
43.	TOTAL OTHER	-	-	-	-
44.	TOTAL OPERATING EXPENSES	23,586,639	1,472,532	(29,663,656)	(3,708,899)
45.	ELECTRIC OPERATING MARGINS	(14,946,695)	(1,472,532)	(13,210,326)	(2,271,204)
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT	-	-	-	-
47.	INTEREST CHARGES TO CONSTR	-	-	-	-
48.	OTHER INTEREST EXPENSE	-	-	-	-
49.	OTHER DEDUCTIONS	-	-	-	-
50.	TOTAL INTEREST & OTHER DEDUCTIONS	-	-	-	-
51.	OPERATING MARGINS	(14,946,695)	(1,472,532)	(13,210,326)	(2,271,204)
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	-	-	-	-
53.	AFUDC	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	-
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	-
55a.	EXTRAORDINARY ITEMS	-	-	-	-
56.	NET INCOME (MARGINS)	$ (14,946,695)	$ (1,472,532)	$ (13,210,326)	$ (2,271,204)

SUPPORTING SCHEDULES:
(1) Adjustments - Coal Price Adjustment
(2) Adjustments - Payroll and Pension Adjustment
(3) Adjustments - Contract Termination Adjustment Spreadsheet
(4) Adjustments - Contract Termination Adjustment Spreadsheet

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

10/1/2009

LINE NO.		5 PNM PPA CONTRACT EXPIR. ADJUSTMENT	6 MEC ADD. SALES ADJUSTMENT	7 SSVEC ADD. SALES ADJUSTMENT	8 ARM COAL & PURCHASED POWER ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ 6,783,251	$ 6,007,034	$ -
2.	FUEL ADJUSTMENT	-	1,938,796	1,717,095	-
3.	NON-CLS A, NON-FIRM & NON-ME	-	-	-	-
4.	TOTAL ELECTRIC	-	8,722,047	7,724,129	-
5.	OTHER OPERATING REVENUE	-	-	-	-
6.	TOTAL OPERATING REVENUE	-	8,722,047	7,724,129	-
	OPERATING EXPENSES:				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	-	7,704,987	6,757,515	6,820,457
8.	PRODUCTION - STEAM A/C 500	-	-	-	-
9.	A/C 502	-	-	-	-
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	-	-	-
13.	A/C 506 & 509	-	-	-	-
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	-
17.	A/C 548	-	-	-	-
18.	A/C 549	-	-	-	-
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				
20.	- DEMAND A/C 555	(2,925,000)	-	-	-
21.	- ENERGY A/C 555	(1,787,636)	(4,286,793)	(3,007,381)	(13,285,245)
22.	A/C 556	-	-	-	-
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	-	-	-	-
25.	ADMINISTRATIVE & GENERAL	-	-	-	-
26.	TOTAL OPERATIONS	$ (4,712,636)	$ 3,418,194	$ 3,750,134	$ (6,464,788)
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	-	-	-
28.	A/C 511	-	-	-	-
29.	A/C 512	-	-	-	-
30.	A/C 513	-	-	-	-
31.	A/C 514	-	-	-	-
32.	A/C 515	-	-	-	-
33.	PRODUCTION - OTHER - A/C 551	-	-	-	-
34.	A/C 552	-	-	-	-
35.	A/C 553	-	-	-	-
36.	A/C 554	-	-	-	-
37.	TRANSMISSION	-	-	-	-
38.	GENERAL PLANT	-	-	-	-
39.	TOTAL MAINTENANCE	-	-	-	-

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		5 PNM PPA CONTRACT TERM. ADJUSTMENT	6 MEC ADD. SALES ADJUSTMENT	7 SSVEC ADD. SALES ADJUSTMENT	8 ARM COAL & PURCHASED POWER ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	-	-	-	-
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	-
43.	TOTAL OTHER	-	-	-	-
44.	TOTAL OPERATING EXPENSES	(4,712,636)	3,418,194	3,750,134	(6,464,788)
45.	ELECTRIC OPERATING MARGINS	4,712,636	5,303,853	3,973,995	6,464,788
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT	-	-	-	-
47.	INTEREST CHARGES TO CONSTR	-	-	-	-
48.	OTHER INTEREST EXPENSE	-	-	-	-
49.	OTHER DEDUCTIONS	-	-	-	-
50.	TOTAL INTEREST & OTHER DEDUCTIONS	-	-	-	-
51.	OPERATING MARGINS	4,712,636	5,303,853	3,973,995	6,464,788
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	-	-	-	-
53.	AFUDC	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	-
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	-
55a.	EXTRAORDINARY ITEMS	-	-	-	-
56.	NET INCOME (MARGINS)	$ 4,712,636	$ 5,303,853	$ 3,973,995	$ 6,464,788

SUPPORTING SCHEDULES.

(5) Adjustments - Contract Termination Adjustment Spreadsheet
(6) Adjustments - Contract Termination Adjustment Spreadsheet
(7) Adjustments - Contract Termination Adjustment Spreadsheet
(8) Adjustments - Contract Termination Adjustment Spreadsheet

Arizona Electric Power Cooperative, Inc.
Income Statement Pro Forma Adjustments

LINE NO.		9 MAINTENANCE OUTAGE ADJUSTMENT	10 SAP SOFTWARE AMORTIZATION ADJUSTMENT	11 MERCURY CONTROL ADJUSTMENT	12 SOUTHPOINT PPA CAPACITY ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ -	$ -
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	-	-	-	-
4.	TOTAL ELECTRIC	-	-	-	-
5.	OTHER OPERATING REVENUE	-	-	-	-
6.	TOTAL OPERATING REVENUE	0	0	0	0
	OPERATING EXPENSES				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	0	0	0	0
8.	PRODUCTION - STEAM A/C 500	0	0	0	0
9.	A/C 502	0	0	2,804,076	0
10.	A/C 503	0	0	0	0
11.	A/C 504	0	0	0	0
12.	A/C 505	0	0	0	0
13.	A/C 506 & 509	0	0	0	0
14.	A/C 507	0	0	0	0
15.	A/C 508	0	0	0	0
16.	PRODUCTION - OTHER - A/C 546	0	0	0	0
17.	A/C 548	0	0	0	0
18.	A/C 549	0	0	0	0
19.	A/C 550	0	0	0	0
	OTHER POWER SUPPLY				
20.	- DEMAND A/C 555	0	0	0	(232,500)
21.	- ENERGY A/C 555	0	0	0	0
22.	A/C 556	0	0	0	0
23.	A/C 557	0	0	0	0
24.	TRANSMISSION	0	0	0	0
25.	ADMINISTRATIVE & GENERAL	0	0	0	0
26.	TOTAL OPERATIONS	0	0	2,804,076	(232,500)
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	0	0	0	0
28.	A/C 511	0	0	0	0
29	A/C 512	(818,350)	0	0	0
30.	A/C 513	(561,044)	0	0	0
31	A/C 514	0	0	0	0
32	A/C 515	0	0	0	0
33	PRODUCTION - OTHER - A/C 551	0	0	0	0
34.	A/C 552	3,162,500	0	0	0
35.	A/C 553	346,192	0	0	0
36.	A/C 554	0	0	0	0
37.	TRANSMISSION	0	0	0	0
38.	GENERAL PLANT	0	0	0	0
39.	TOTAL MAINTENANCE	$ 2,129,298	$ -	$ -	$ -

Arizona Electric Power Cooperative, Inc.
Income Statement Pro Forma Adjustments

LINE NO.		9 MAINTENANCE OUTAGE ADJUSTMENT	10 SAP SOFTWARE AMORTIZATION ADJUSTMENT	11 MERCURY CONTROL ADJUSTMENT	12 SOUTHPOINT PPA CAPACITY ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	0	464,285	0	0
41.	ACC GROSS REVENUE TAXES	0	0	0	0
42.	TAXES	0	0	0	0
43.	TOTAL OTHER	0	464,285	0	0
44.	TOTAL OPERATING EXPENSES	2,129,298	464,285	2,804,076	(232,500)
45.	ELECTRIC OPERATING MARGINS	(2,129,298)	(464,285)	(2,804,076)	232,500
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT	0	0	0	0
47.	INTEREST CHARGES TO CONSTR	0	0	0	0
48.	OTHER INTEREST EXPENSE	0	360,470	0	0
49.	OTHER DEDUCTIONS	0	0	0	0
50.	TOTAL INTEREST & OTHER DEDUCTIONS	0	360,470	0	0
51.	OPERATING MARGINS	(2,129,298)	(824,755)	(2,804,076)	232,500
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	0	0	0	0
53.	AFUDC	0	0	0	0
54.	OTHER NONOPERATING INCOME	0	0	0	0
55.	TOTAL OTHER NON OPERATING INCOME	0	0	0	0
55a.	EXTRAORDINARY ITEMS	0	0	0	0
56.	NET INCOME (MARGINS)	$ (2,129,298)	$ (824,755)	$ (2,804,076)	$ 232,500

SUPPORTING SCHEDULES:

(9) Adjustments - Maintenance Outage Adjustment

(10) Adjustments - SAP Software Amortization Adjustment

(11) Adjustments - Mercury Control Chemicals Adjustment

(12) Adjustments - Southpoint PPA Capacity Adjustment

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		13 RATE CASE AMORTIZATION ADJUSTMENT	14 INTEREST ADJUSTMENT	15 REVENUE SYNCHRONIZATION ADJUSTMENT	TOTAL PRO-FORMA ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ (61,231)	$ 12,729,054
2.	FUEL ADJUSTMENT	-	-	2,119,038	5,774,929
3.	NON-CLS A, NON-FIRM & NON-ME	-	-	-	(40,214,141)
4.	TOTAL ELECTRIC	-	-	2,057,807	(21,710,158)
5.	OTHER OPERATING REVENUE	-	-	-	-
6.	TOTAL OPERATING REVENUE	-	-	2,057,807	(21,710,158)
	OPERATING EXPENSES				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	-	-	-	16,520,095
8.	PRODUCTION - STEAM A/C 500	-	-	-	354,307
9.	A/C 502	-	-	-	2,839,932
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	-	-	-
13.	A/C 506 & 509	-	-	-	20,818
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	13,891
17.	A/C 548	-	-	-	1,405
18.	A/C 549	-	-	-	816
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				-
20.	- DEMAND A/C 555	-	-	-	(3,157,500)
21.	- ENERGY A/C 555	-	-	-	(22,367,055)
22.	A/C 556	-	-	-	109,150
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	-	-	-	(4,963,137)
25.	ADMINISTRATIVE & GENERAL	160,000	-	-	540,635
26.	TOTAL OPERATIONS	160,000	-	-	(10,086,643)
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	-	-	85,151
28.	A/C 511	-	-	-	1,342
29	A/C 512	-	-	-	(680,227)
30.	A/C 513	-	-	-	(533,229)
31	A/C 514	-	-	-	105,664
32	A/C 515	-	-	-	-
33	PRODUCTION - OTHER - A/C 551	-	-	-	3,337
34.	A/C 552	-	-	-	3,164,043
35.	A/C 553	-	-	-	376,795
36.	A/C 554	-	-	-	6,042
37.	TRANSMISSION	-	-	-	526
38.	GENERAL PLANT	-	-	-	95,593
39.	TOTAL MAINTENANCE	$ -	$ -	$ -	$ 2,625,037

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		13 RATE CASE AMORTIZATION ADJUSTMENT	14 INTEREST ADJUSTMENT	15 REVENUE SYNCHRONIZATION ADJUSTMENT	TOTAL PRO-FORMA ADJUSTMENTS
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ 464,285
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	-
43.	TOTAL OTHER	-	-	-	464,285
44.	TOTAL OPERATING EXPENSES	160,000	-	-	(6,997,321)
45.	ELECTRIC OPERATING MARGINS	(160,000)	-	2,057,807	(14,712,837)
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT		231,437	-	231,437
47.	INTEREST CHARGES TO CONSTR		-	-	-
48.	OTHER INTEREST EXPENSE		-	-	360,470
49.	OTHER DEDUCTIONS		-	-	-
50.	TOTAL INTEREST & OTHER DEDUCTIONS	-	231,437	-	591,907
51.	OPERATING MARGINS	(160,000)	(231,437)	2,057,807	(15,304,744)
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	-	-	-	-
53.	AFUDC	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	-
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	-
55a.	EXTRAORDINARY ITEMS	-	-	-	-
56.	NET INCOME (MARGINS)	$ (160,000)	$ (231,437)	$ 2,057,807	$ (15,304,744)

SUPPORTING SCHEDULES:
(13) Adjustments - Rate Case Amortization Adjustment
(14) Adjustments - Interest Expense Adjustment

Arizona Electric Power Cooperative, Inc.

Computation of Gross Revenue Conversion Factor

SCHEDULE C-3

10/1/2009

LINE NO.		PERCENTAGE OF INCREMENTAL GROSS REVENUES
1.	FEDERAL INCOME TAX RATE	0.00000
2.	STATE INCOME TAX RATE	0.00000
3.	CORPORATION COMMISSION GROSS REVENUE TAX RATE	0.00157
4.	TOTAL TAX PERCENTAGE **	0.00157
5.	OPERATING INCOME PERCENT	0.00000
6.	GROSS REVENUE CONVERSION FACTOR (a)	0.00000

** Included as both a revenue and an expense so no revenue conversion adjustment required **

RECAPSCHEDULES:

D

Arizona Electric Power Cooperative, Inc.

Summary Cost of Capital

SCHEDULE D-1
10/1/2009

END OF ACTUAL TEST YEAR 3/31/2009

LINE NO.	INVESTED CAPITAL		AMOUNT (b)	%	COST RATE	COMPOSITE (b)
1.	LONG-TERM DEBT (a)	$	178,093,188	91.83%	6.07%	5.57%
2.	SHORT-TERM DEBT (a)		15,851,384	8.17%	4.25%	0.35%
3.	TOTAL	$	193,944,572	100.00%		5.92%

END OF PROJECTED YEAR 3/31/2010

	INVESTED CAPITAL		AMOUNT (b)	%	COST RATE	COMPOSITE (b)
4.	LONG-TERM DEBT (a)	$	192,789,771	92.40%	5.72%	5.28%
5.	SHORT-TERM DEBT (a)		15,851,384	7.60%	4.25%	0.32%
6.	TOTAL	$	208,641,155	100.00%		5.60%

SUPPORTING SCHEDULES:
(a) D-2

RECAP SCHEDULES:
(b) A-3

Arizona Electric Power Cooperative, Inc.
Cost Of Long-Term and Short-Term Debt

SCHEDULE D-2
10/1/2009

LINE NO.		END OF ACTUAL TEST YEAR 3/31/2009 OUTSTANDING	FACE RATE	ANNUAL INTEREST	END OF PROJECTED YEAR 3/31/2010 OUTSTANDING	FACE RATE	ANNUAL INTEREST
1.	FFB DEBT	$ 111,662,701	5.871%	$ 6,555,717	$ 146,124,707	5.450%	$ 7,964,074
2.	REA DEBT	487,450	5.000%	24,373	-	5.000%	-
4.	CFC SERIES 1994A BONDS	15,372,414	4.400%	676,386	14,765,608	4.400%	649,687
5.	CENTRAL BANK FOR COOPERATIVES	21,116,169	7.740%	1,634,391	19,351,712	7.740%	1,497,823
6.	NRUCFC	29,454,454	5.406%	1,592,327	12,547,744	5.116%	642,002
7.	REGULATORY ASSET	-	-	329,000	-	-	268,500
8.	TOTAL LONG-TERM (b)	$ 178,093,188	6.071%	$ 10,812,194	$ 192,789,771	5.717%	$ 11,022,086
9.	COST RATE (b)			6.071%			5.717%
	SHORT TERM:	15,851,384	4.250%	$ 673,684	15,851,384	4.250%	$ 673,684
10.	SHORT-TERM DEBT (b)	$ 15,851,384	4.250%	$ 673,684	$ 15,851,384		$ 673,684
11.	COST RATE (b)			4.250%			4.250%

LINE NO.		END OF YEAR 3/31/2007 OUTSTANDING (a)	FACE RATE	ANNUAL INTEREST	END OF YEAR 3/31/2008 OUTSTANDING (a)	FACE RATE	ANNUAL INTEREST
	LONG-TERM DEBT:						
1.	FFB DEBT	$ 133,681,423	5.909%	$ 7,899,235	$ 120,853,445	5.902%	$ 7,132,770
2.	REA DEBT	1,895,951	4.755%	90,152	1,230,992	4.942%	60,836
3	CFC SERIES 1997C BONDS	1,985,603	5.050%	100,273	-	0.000%	-
4.	CFC SERIES 1994A BONDS	16,451,180	3.600%	592,242	15,911,797	2.600%	413,707
5.	CENTRAL BANK FOR COOPERATIVES	24,049,064	7.740%	1,861,398	22,670,265	7.740%	1,754,679
6.	NRUCFC	7,620,536	7.155%	545,249	1,080,108	4.900%	52,925
7.	REGULATORY ASSET	-	0.000%	498,000	-	0.000%	387,500
8.	TOTAL LONG-TERM DEBT (b)	$ 185,683,757		$ 11,586,549	$ 161,746,607		$ 9,802,417
9.	COST RATE (b)			6.240%			6.060%
	SHORT TERM:	15,017,463	5.150%	$ 773,399	24,771,128	7.150%	$ 1,771,136
10.	SHORT-TERM DEBT (b)	$ 15,017,463		$ 773,399	$ 24,771,128		$ 1,771,136
11.	COST RATE (b)			5.150%			7.150%

SUPPORTING SCHEDULES:
(a) E-1, PAGE 2

RECAP SCHEDULES:
(b) A-3

Arizona Electric Power Cooperative, Inc.

SCHEDULE D-3

Cost Of Prefered Stock

10/1/2009

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

Cost of Common Stock

SCHEDULE D-4

10/1/2009

NOT APPLICABLE

E

Arizona Electric Power Cooperative, Inc.

Comparative Balance Sheets

LINE NO.		PER BOOKS 3/31/2009	PRIOR YEAR 3/31/2008	PRIOR YEAR 3/31/2007
	ASSETS			
	UTILITY PLANT:			
1.	UTILITY PLANT IN SERVICE	$ 399,424,364	$ 393,570,634	$ 400,661,362
2.	LESS: ACCUMULATED DEPRECIATION AND AMORTIZATION	(204,796,249)	(200,735,187)	(206,328,011)
3.	TOTAL UTILITY PLANT IN SERVICE	194,628,115	192,835,447	194,333,351
4.	CONSTRUCTION WORK IN PROGRESS	23,593,561	7,980,425	7,243,123
5.	PLANT HELD FOR FUTURE USE	2,551,631	2,224,466	2,224,466
6.	NET UTILITY PLANT (a)	220,773,307	203,040,338	203,800,940
	CURRENT ASSETS:			
7.	GENERAL FUND CASH	758,225	590,122	472,694
8.	TEMPORARY INVESTMENTS	970,595	8,679,313	4,758,818
9.	ACCOUNTS RECEIVABLE	17,835,024	26,074,020	22,679,149
10.	FUEL INVENTORY	25,281,373	12,670,242	5,247,527
11.	MATERIALS AND SUPPLIES	6,713,415	6,232,510	6,503,453
12.	PREPAYMENTS & OTHER CURRENT ASSETS	1,812,669	1,169,539	1,007,462
13.	NOTES RECEIVABLE-CURRENT	-	-	-
14.	OTHER	922,940	144,115	364,377
15.	TOTAL CURRENT ASSETS	54,294,241	55,559,861	41,033,480
	OTHER ASSETS:			
16.	INV - ASSOC ORG	14,200,452	10,612,318	12,670,128
17.	INVESTMENTS	2,827,057	6,216,349	6,185,278
18.	DEFERRED DEBITS	12,850,764	7,124,355	2,531,593
19.	UNAMORTIZED DEBT	314,401	374,245	440,468
20.	REGULATORY ASSETS	-	-	5,915,646
21.	TOTAL OTHER ASSETS	30,192,674	24,327,267	27,743,113
22.	TOTAL ASSETS	$ 305,260,222	$ 282,927,466	$ 272,577,533

Arizona Electric Power Cooperative, Inc.

Comparative Balance Sheets

LINE NO.		PER BOOKS 3/31/2009	PRIOR YEAR 3/31/2008	PRIOR YEAR 3/31/2007
	LIABILITIES & EQUITY			
	EQUITY: (c) (d)			
23.	PATRONAGE CAPITAL	$ 57,202,299	$ 25,455,177	$ 17,803,668
24.	UNALLOCATED MARGINS	18,664,549	34,577,656	9,620,225
25.	TOTAL EQUITY	75,866,848	60,032,833	27,423,893
	LIABILITIES:			
	LONG-TERM DEBT: (b)			
26.	FFB DEBT	111,662,701	120,853,445	133,681,423
27.	REA DEBT	487,450	1,230,992	1,895,951
28.	PAYMENTS UNAPPLIED	(1,936)	-	-
29.	CFC 1997C BONDS	-	-	1,985,603
30.	CFC 1994A BONDS	15,372,414	15,911,797	16,451,180
31.	COOPERATIVE UTILITY TRUST	21,116,169	22,670,265	24,049,064
32.	NRUCFC	29,454,454	1,080,108	7,620,536
33.	LESS CURRENT MATURITIES	(6,783,417)	(14,056,086)	(17,910,459)
34.	TOTAL LONG-TERM DEBT	171,307,835	147,690,521	167,773,298
35.	OBLIGATIONS UNDER CAPITAL LEASES	2,187,848	2,187,848	-
	CURRENT LIABILITIES:			
36.	MEMBER ADVANCES & NOTES	15,851,384	24,771,128	15,017,463
37.	ACCOUNTS PAYABLE	18,046,827	17,390,453	14,397,789
38.	ACCRUED TAXES	2,505,770	3,121,044	2,727,516
39.	ACCRUED INTEREST	264,400	250,826	404,564
40.	CURRENT LIABILITY - OTHER	1,169,934	1,324,421	3,439,670
41.	CURRENT MATURITIES OF LONG TERM DEBT	6,783,417	14,056,086	17,910,459
42.	TOTAL CURRENT LIABILITIES	44,621,732	60,913,958	53,897,461
43.	ACCUMULATED OPERATING PROVISIONS	1,654,712	1,439,346	5,537,314
44.	DEFERRED CREDITS	9,621,247	10,662,960	17,945,567
45.	TOTAL LIABILITIES AND EQUITY	$ 305,260,222	$ 282,927,466	$ 272,577,533

SUPPORTING SCHEDULES:
(a) E-5, PAGE 2
(b) D-2, D-2A AND GENERAL LEDGER
(c) E-4

RECAP SCHEDULES:
(d) A-3 Line 5

Arizona Electric Power Cooperative, Inc.

Comparative Income Statements

LINE NO.		ACTUAL TEST YEAR 3/31/2009 (b)	PRIOR YEAR 3/31/2008	PRIOR YEAR 3/31/2007
	REVENUES:			
1.	CLASS A MEMBERS	$ 112,717,749	$ 121,706,484	$ 116,023,863
2.	FUEL ADJUSTMENT	35,644,363	31,778,337	21,145,239
3.	NON-CIS A, N-FIRM & N-MEMB	48,834,238	50,225,790	42,029,953
4.	TOTAL ELECTRIC REVENUE	197,196,350	203,710,611	179,199,055
5.	OTHER OPERATING REVENUE	12,785,434	16,167,234	16,772,920
6.	TOTAL OPERATING REVENUE	209,981,784	219,877,845	195,971,975
	OPERATING EXPENSES			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	72,540,278	67,118,456	62,123,859
8.	PRODUCTION - STEAM A/C 500	5,997,229	6,495,910	5,349,768
9.	A/C 502	2,795,766	3,028,239	2,493,935
10.	A/C 503	-	-	-
11.	A/C 504	-	-	-
12.	A/C 505	1,385,698	1,500,921	1,236,098
13.	A/C 506	1,083,857	1,173,982	966,844
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	234,983	254,523	209,615
17.	A/C 548	707,145	765,945	630,801
18.	A/C 549	39,148	42,403	34,921
19.	A/C 550	-	-	-
	OTHER POWER SUPPLY	-		
20.	-DEMAND A/C 555	6,274,506	7,695,611	2,502,598
21.	- ENERGY A/C 555	35,795,430	39,809,116	32,588,227
22.	A/C 556	3,315,542	2,166,738	1,793,912
23.	A/C 557	1,548,021	86,886	476,286
24.	TRANSMISSION	16,345,977	24,271,032	25,872,662
25.	ADMINISTRATIVE & GENERAL	11,249,966	8,666,853	11,175,967
26.	TOTAL OPERATIONS	159,313,546	163,076,615	147,455,493
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	1,302,263	1,411,447	1,119,132
28.	A/C 511	26,944	29,203	23,155
29.	A/C 512	4,763,936	5,163,353	4,094,004
30.	A/C 513	6,184,656	6,703,189	5,314,935
31.	A/C 514	2,334,541	2,530,273	2,006,245
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	51,049	55,329	43,870
34.	A/C 552	27,641	29,958	23,754
35.	A/C 553	1,384,550	1,500,633	1,189,847
36.	A/C 554	175,654	190,381	150,952
37.	TRANSMISSION	13,624	37,620	382,115
38.	GENERAL PLANT	304,878	36,823	-
39.	TOTAL MAINTENANCE	16,569,736	17,688,210	14,348,009

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-:

Comparative Income Statements

10/1/2(

LINE NO.		ACTUAL TEST YEAR 3/31/2009 (b)	PRIOR YEAR 3/31/2008	PRIOR YEAR 3/31/2007
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 7,883,883	$ 8,227,983	$ 7,693,790
41.	ACC GROSS REVENUE TAXES	-	-	-
42.	TAXES	-	-	987
43.	TOTAL OTHER	7,883,883	8,227,983	7,694,777
44.	TOTAL OPERATING EXPENSES	183,767,165	188,992,808	169,498,279
45.	ELECTRIC OPERATING MARGINS	26,214,619	30,885,037	26,473,696
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	10,580,757	10,899,120	12,250,444
47.	INTEREST CHARGES TO CONSTR	(187,816)	(115,946)	(113,795)
48.	OTHER INTEREST EXPENSE	781,804	1,640,895	1,444,683
49.	OTHER DEDUCTIONS	151,174	(1,126,086)	(431,077)
50.	TOTAL INTEREST & OTHER DEDUCTIONS	11,325,919	11,297,983	13,150,255
51.	OPERATING MARGINS	14,888,700	19,587,054	13,323,441
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	546,419	773,784	855,503
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	398,896	1,050,516	511,617
55.	TOTAL OTHER NON OPERATING INCOME	945,315	1,824,300	1,367,120
55a.	EXTRAORDINARY ITEMS	-	-	-
56.	NET INCOME (MARGINS) (c)	$ 15,834,015	$ 21,411,354	$ 14,690,561

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(b) C-1 PAGES 1 & 2
(c) A-2

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-3

Comparative Statement of Changes in Financial Position

10/1/2009

LINE NO.			PER BOOKS 3/31/2009	PRIOR YEAR 3/31/2008	PRIOR YEAR 3/31/2007
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1.	NET MARGIN	(a)	$ 15,834,015	$ 21,411,354	$ 14,690,561
	ADJUSTMENTS TO RECONCILE NET MARGIN TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES-				
2.	DEPREC. & AMORT.		7,883,883	8,227,984	7,453,614
3.	AMORTIZATION OF DEFERRED CHARGES		77,988	84,367	90,405
4.	AMORTIZATION OF OTHER DEFERRED CREDITS		(337,280)	(337,280)	(337,280)
5.	CUMULATIVE EFFECRT OF CHANGE IN ACCOUNTING PRINCIPLE		-	11,197,584	-
	CHANGES IN ASSETS AND LIABILITIES				
6.	RESTRICTED CASH AND CASH EQUIVALENTS		2,427,313	(54,573)	(850,419)
7.	RECEIVABLES		8,202,346	(3,329,948)	(975,115)
8.	INVENTORIES		(13,092,037)	(7,151,772)	(301,926)
9.	DEFERRED DEBITS		(610,070)	8,221	(909,765)
10.	ACCOUNTS PAYABLE		656,374	2,992,170	8,003,953
11.	ACCRUED INTEREST PAYABLE		13,574	(153,738)	71,928
12.	SHORTFALL CHARGE-BACK CONTINGENCY				
13.	ACCRUED OVERHAUL		(5,134,485)	(4,619,126)	(1,718,634)
14.	OTHER , NET		(2,305,291)	(5,893,439)	3,425,832
	NET CASH PROVIDED BY OPERATING ACTIVITIES	(b)	13,616,330	22,381,804	28,643,154
	CASH FLOWS FROM INVESTING ACTIVITIES:				
15.	CONSTRUCTION EXPENDITURES, NET (c)		(25,616,852)	(7,467,384)	(9,434,638)
16.	RESTRUCTURING TRANSFER OF CASH & CASH EQ.				
17.	MATURITIES OF INVESTMENTS		116,219	2,230,217	116,317
18.	PURCHASE OF INVESTMENTS		(3,700,747)	(187,239)	(1,076,362)
19.	PATRONAGE CAPITAL RETIREMENT		-	-	-
20.	NET CASH USED IN INVESTING ACTIVITIES	(b)	(29,201,380)	(5,424,406)	(10,394,683)
	CASH FLOWS FROM FINANCING ACTIVITIES:				
21.	MEMBER ADVANCES, NET		1,670,757	6,950,718	214,820
22.	ISSUANCE OF LONG-TERM DEBT		30,386,500	-	-
23.	RETIREMENT OF LONG-TERM DEBT		(14,041,855)	(23,937,148)	(16,948,927)
24.	LINE OF CREDIT ACTIVITY, NET		(10,043,050)	4,093,050	(350,000)
25.	MEMBERSHIP FEES		-	-	100
26.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(b)	7,972,352	(12,893,380)	(17,084,007)
27.	NET DECREASE IN CASH AND CASH EQ.	(b)	(7,612,698)	4,064,018	1,164,464
28.	CASH AND CASH EQUIVALENTS, April 1		8,831,428	4,767,410	3,602,946
29.	CASH AND CASH EQUIVALENTS, March 31		$ 1,218,730	$ 8,831,428	$ 4,767,410
	SUPPLEMENTAL DISCLOSURES:				
30.	CASH PAID FOR INTEREST, NET OF AMOUNT CAPITALIZED		$ 11,083,183	$ 12,577,807	$ 13,509,404

SUPPORTING SCHEDULES:
(a) C-1, PAGE 2

RECAP SCHEDULES:
(b) A-5
(c) A-4

Arizona Electric Power Cooperative, Inc.

Statement of Change in Equity

SCHEDULE E-4
10/1/2009

LINE NO.			PATRONAGE CAPITAL			UNALLOCATED MARGINS	
1.	BALANCE, MARCH 31, 2006	$	8,183,443		$	(5,069,700)	
2.	UNALLOCATED MARGINS CHANGE		-			14,689,925	
3.	BALANCE, MARCH 31, 2007		17,803,668	(a)		9,620,225	
4.	UNALLOCATED MARGINS CHANGE		-			24,957,431	
5.	BALANCE, MARCH 31, 2008		25,455,177			34,577,656	(a)
6.	UNALLOCATED MARGINS CHANGE		-			(31,747,122)	
7.	NET EARNINGS (LOSS)					15,834,015	
8.	BALANCE, MARCH 31, 2009\1	$	57,202,299	(a)	$	18,664,549	(a)

SUPPORTING SCHEDULES:

\1. As reflected by REA Form 12a (Unaudited)

RECAP SCHEDULES:
(a) E-1, PAGE 2

Arizona Electric Power Cooperative, Inc.
Detail of Utility Plant

LINE NO.		END OF PRIOR YEAR 3/31/2008 /1	NET ADDITIONS	ACTUAL TEST YEAR 3/31/2009 /2	PRO FORMA ADJUSTMENT (a)	ADJUSTED TEST YEAR 3/31/2009
	INTANGIBLE PLANT:					
1.	301 ORGANIZATION	$ 4,545	$ -	$ 4,545	$ -	$ 4,545
2.	114 ACQUISITION ADJUSTMENT	-	-	-	-	-
3.	302 FRANCHISE AND CONSENT	745	-	745	-	745
4.	303 MISC. INTANGIBLE PLANT	7,494,523	(1,162,627)	6,331,896	-	6,331,896
5.	SUBTOTAL INTANGIBLE	7,499,813	(1,162,627)	6,337,186	-	6,337,186
	STEAM PRODUCTION PLANT:					
6.	310 LAND AND LAND RIGHTS	3,915,175	-	3,915,175	-	3,915,175
7.	311 STRUCTURES AND IMPROVEMENTS	35,470,405	(150,210)	35,320,195	-	35,320,195
8.	312 BOILER EQUIPMENT	209,486,199	6,210,032	215,696,231	-	215,696,231
9.	314 TURBINE GENERATORS	52,445,104	710,921	53,156,025	-	53,156,025
10.	315 ACCESSORY ELEC. EQUIPMENT	17,710,112	41,340	17,751,452	-	17,751,452
11.	316 MISC. POWER EQUIPMENT	4,119,427	-	4,119,427	-	4,119,427
12.	317 ASSET RETIREMENT OBLIGATION	972,497	120,182	1,092,679	-	1,092,679
13.	SUBTOTAL STEAM PRODUCTION	324,118,919	6,932,265	331,051,184	-	331,051,184
	OTHER PRODUCTION PLANT:					
14.	340 LAND AND LAND RIGHTS	1,160	-	1,160	-	1,160
15.	341 STRUCTURES AND IMPROVEMENTS	713,887	-	713,887	-	713,887
16.	342 FUEL HLDRS PRODCRS & ACCES	2,805,026	-	2,805,026	-	2,805,026
17.	343 PRIME MOVERS	29,660,071	343	29,660,414	-	29,660,414
18.	344 GENERATORS	3,312,541	-	3,312,541	-	3,312,541
19.	345 ACCESSORY ELEC. EQUIPMENT	2,452,313	-	2,452,313	-	2,452,313
20.	346 MISC. POWER EQUIPMENT	915,030	-	915,030	-	915,030
21.	SUBTOTAL OTHER PRODUCTION	39,860,028	343	39,860,371	-	39,860,371
	TRANSMISSION PLANT:					
22.	350 LAND AND LAND RIGHTS	-	-	-	-	-
23.	352 STRUCTURES AND IMPROVEMENTS	-	-	-	-	-
24.	353 STATION EQUIPMENT	2,642,162	-	2,642,162	-	2,642,162
25.	354 TOWERS AND FIXTURES	-	-	-	-	-
26.	355 POLES AND FIXTURES	173,130	-	173,130	-	173,130
27.	356 OVERHEAD CONDUCTORS	74,199	-	74,199	-	74,199
28.	359 ROADS AND TRAILS	-	-	-	-	-
29.	SUBTOTAL TRANSMISSION	2,889,491	-	2,889,491	-	2,889,491

Arizona Electric Power Cooperative, Inc.

Detail of Utility Plant

LINE NO.		END OF PRIOR YEAR 3/31/2008 /1		NET ADDITIONS	ACTUAL TEST YEAR 3/31/2009 /2		PRO FORMA ADJUSTMENT (a)	ADJUSTED TEST YEAR 3/31/2009	
	GENERAL PLANT:								
30.	389 LAND AND LAND RIGHTS	$ 147,861		$ -	$ 147,861		$ -	$ 147,861	
31.	390ACCOUNTS390-399	19,054,522		83,749	19,138,271		-	19,138,271	
32.	SUBTOTAL GENERAL	19,202,383		83,749	19,286,132		-	19,286,132	
	COMPLETED CONST - UNCLASSIFIED								
33.	GENERAL PLANT	-		-	-		-	-	
34.	LINES	-		-	-		-	-	
35.	SUBSTATION	-		-	-		-	-	
36.	GENERATION - STEAM	-		-	-		-	-	
37.	GENERATION - IC	-		-	-		-	-	
38.	TOTAL COMPLETED	-		-	-		-	-	
39.	TOTAL PLANT IN SERVICE	393,570,634	(b) (c)	5,853,730	399,424,364	(b) (c)	-	399,424,364	(d)
	ACCUMULATED DEPRECIATION (d)								
40.	PRODUCTION	(188,126,064)		(6,177,201)	(194,303,265)		-	(194,303,265)	
41.	TRANSMISSION	(1,501,381)		(79,461)	(1,580,842)		-	(1,580,842)	
42.	*RETIREMENTS*	244,516		3,302,791	3,547,307		-	3,547,307	
43.	GENERAL	(9,731,445)		(284,980)	(10,016,425)		-	(10,016,425)	
44.	ELEC PLT IN SERVICE	-		-	-		-	-	
45.	TOTAL	(199,114,374)		(3,238,851)	(202,353,225)		-	(202,353,225)	
46.	ACCUMULATED AMORTIZATION	(1,620,813)		(822,211)	(2,443,024)		-	(2,443,024)	
47.	TOTAL ACCUM DEPREC. & AMORT.	(200,735,187)	(b)	(4,061,062)	(204,796,249)	(b)	-	(204,796,249)	(d)
48.	TOTAL UTILITY PLANT IN SERVICE	192,835,447		1,792,668	194,628,115	(d)	-	194,628,115	(d)
49.	CWIP	7,980,425	(b)	15,613,136	23,593,561	(b)	-	23,593,561	
50.	PLANT HELD FOR FUTURE USE	2,224,466		327,165	2,551,631	(b)	-	2,551,631	(e)
51.	TOTAL NET PLANT IN SERVICE	$ 203,040,338	(b)	$ 17,732,969	$ 220,773,307		$ -	$ 220,773,307	

SUPPORTING SCHEDULES:
(a) E-5, PAGES 3 AND 4

/1 From General Ledger Balance Sheet
/2 From General Ledger Balance Sheet

RECAP SCHEDULES:
(b) E-1, PAGE 1, Lines 1-6
(c) A-4
(d) B-2, Lines 10-14
(e) B-1

Arizona Electric Power Cooperative, Inc.
Detail of Utility Plant Pro Forma Adjustments

LINE NO.			TOTAL
	INTANGIBLE PLANT:		
1.	301 ORGANIZATION	$ -	$ -
2.	114 ACQUISITION ADJUSTMENT	-	-
3.	302 FRANCHISE AND CONSENT	-	-
4.	303 MISC. INTANGIBLE PLANT	-	-
5.	SUBTOTAL INTANGIBLE	-	-
	STEAM PRODUCTION PLANT:		
6.	310 LAND AND LAND RIGHTS	-	-
7.	311 STRUCTURES AND IMPROVEMENTS	-	-
8.	312 BOILER EQUIPMENT	-	-
9.	314 TURBINE GENERATORS	-	-
10.	315 ACCESSORY ELEC. EQUIPMENT	-	-
11.	316 MISC. POWER EQUIPMENT	-	-
12.	317 ASSET RETIREMENT OBLIGATION	-	-
13.	SUBTOTAL STEAM PRODUCTION	-	-
	OTHER PRODUCTION PLANT:		
14.	340 LAND AND LAND RIGHTS	-	-
15.	341 STRUCTURES AND IMPROVEMENTS	-	-
16.	342 FUEL HLDRS PRODCRS & ACCES	-	-
17.	343 PRIME MOVERS	-	-
18.	344 GENERATORS	-	-
19.	345 ACCESSORY ELEC. EQUIPMENT	-	-
20.	346 MISC. POWER EQUIPMENT	-	-
21.	SUBTOTAL OTHER PRODUCTION	-	-
	TRANSMISSION PLANT:		
22.	350 LAND AND LAND RIGHTS	-	-
23.	352 STRUCTURES AND IMPROVEMENTS	-	-
24.	353 STATION EQUIPMENT	-	-
25.	354 TOWERS AND FIXTURES	-	-
26.	355 POLES AND FIXTURES	-	-
27.	356 OVERHEAD CONDUCTORS	-	-
28.	359 ROADS AND TRAILS	-	-
29.	SUBTOTAL TRANSMISSION	-	-

Arizona Electric Power Cooperative, Inc.
Detail of Utility Plant Pro Forma Adjustments

LINE NO.			TOTAL
	GENERAL PLANT:		
30.	389 LAND AND LAND RIGHTS	$ -	$ -
31.	390ACCOUNTS390-399	-	-
32.	SUBTOTAL GENERAL	-	-
	COMPLETED CONST - UNCLASSIFIED		
33.	GENERAL PLANT	-	-
34.	LINES	-	-
35.	SUBSTATION	-	-
36.	GENERATION - STEAM	-	-
37.	GENERATION - IC	-	-
38.	TOTAL COMPLETED	-	-
39.	TOTAL PLANT IN SERVICE	-	-
	ACCUMULATED DEPRECIATION		
40.	PRODUCTION	-	-
41.	TRANSMISSION	-	-
42.	RETIREMENTS	-	-
43.	GENERAL	-	-
44.	ELEC PLT IN SERVICE	-	-
45.	TOTAL	-	-
46.	ACCUMULATED AMORTIZATION	-	-
47.	TOTAL ACCUM DEPREC. & AMORT.	-	-
48.	NET PLANT IN SERVICE	-	-
49.	CWIP	-	-
50.	PLANT HELD FOR FUTURE USE	-	-
51.	TOTAL NET PLANT	$ -	$ -

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-6

Statement of Change in Equity

10/1/2009

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

Operating Statistics

SCHEDULE E-7
10/1/2009

LINE NO.	ELECTRIC STATISTICS	TEST YEAR ENDED 3/31/2009	PRIOR YEAR ENDED 3/31/2008	PRIOR YEAR ENDED 3/31/2007
	MWH SALES:			
1.	CLASS A MEMBERS	2,027,671,490	2,529,040,979	2,279,959,691
2.	OTHER FIRM CONTRACTS	1,117,704,528	1,002,646,636	1,085,878,850
3.	TOTAL	3,145,376,018	3,531,687,615	3,365,838,541
	AVERAGE NO. CUSTOMERS:			
4.	CLASS A MEMBERS	6	6	6
5.	OTHER FIRM CONTRACTS	3	3	3
6.	TOTAL	9	9	9
	AVERAGE MWH USE:			
7.	CLASS A MEMBERS	337,945,248	421,506,830	379,993,282
8.	OTHER FIRM CONTRACTS	372,568,176	334,215,545	361,959,617
9.	TOTAL	710,513,424	755,722,375	741,952,899
10.	KWH PRODUCTION EXPENSE (a)	$ 108,335,708	$ 106,927,572	$ 94,712,086

SUPPORTING SCHEDULES:
(a) G-4, Page 1

Arizona Electric Power Cooperative, Inc.

Taxes Charged to Operations

SCHEDULE E-8
10/1/2009

LINE NO.	DESCRIPTION:		PER BOOKS 3/31/2009		PRIOR YEAR ENDED 3/31/2008		PRIOR YEAR ENDED 3/31/2007
	FEDERAL TAXES:						
1.	PAYROLL ESTIMATED	$	621,698	$	557,198	$	551,219
	FEDERAL INCOME		-		-		-
	TOTAL FEDERAL TAXES		621,698		557,198		551,219
	STATE TAXES:						
2.	PAYROLL ESTIMATED		89,163		83,428		93,667
3.	PROPERTY		2,933,343		3,340,972		2,885,174
4.	STATE INCOME		50		50		50
5.	CALIFORNIA FRANCHISE TAX		859		852		837
6.	PAYROLL ESTIMATED	$	3,023,415	$	3,425,302	$	2,979,728

Arizona Electric Power Cooperative, Inc.
Notes to Financial Statements

SEE FINANCIAL STATEMENTS

F

Arizona Electric Power Cooperative, Inc.

Projected Income Statement / Present and Proposed Rates

LINE NO.		-ACTUAL- TESTYEAR 3/31/2009	-PROJECTED YEAR- PRESENT RATES 3/31/2009 (a)	PROPOSED RATES 3/31/2009
	REVENUES:			
1.	CLASS A MEMBERS	$ 112,717,749	$ 125,199,347	129,222,367
2.	FUEL ADJUSTMENT	35,644,363	41,419,292	41,419,292
3.	NON-CIS A, N-FIRM & N-MEMB	48,834,238	8,620,097	8,620,097
4.	TOTAL ELECTRIC REVENUE	197,196,350	175,238,736	179,261,756
5	OTHER OPERATING REVENUE	12,785,434	3,523,943	3,523,943
6.	TOTAL OPERATING REVENUE (b)	209,981,784	178,762,679	182,785,699
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	72,540,278	88,508,998	88,508,998
8.	PRODUCTION - STEAM A/C 500	5,997,229	6,351,536	6,351,536
9.	A/C 502	2,795,766	3,927,598	3,927,598
10.	A/C 503	-	-	-
1L	A/C 504	-	-	-
12.	A/C 505	1,385,698	876,286	876,286
13.	A/C 506	1,083,857	1,104,675	1,104,675
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	234,983	248,874	248,874
17.	A/C 548	707,145	199,187	199,187
18.	A/C S49	39,148	39,964	39,964
19.	A/C 550	-	-	-
	OTHER POWER SUPPLY	-	-	-
20.	-DEMAND A/C 555	6,274,506	3,117,006	3,117,006
21.	- ENERGY A/C 555	35,795,430	13,428,375	13,428,375
22.	A/C 556	3,315,542	2,591,246	2,591,246
23.	A/C 557	1,548,021	-	-
24.	TRANSMISSION	16,345,977	4,502,816	4,502,816
25.	ADMINISTRATIVE & GENERAL	11,249,966	12,054,892	12,054,892
26.	TOTAL OPERATIONS	159,313,546	136,951,453	136,951,453
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	1,302,263	1,387,414	1,387,414
28.	A/C 511	26,944	28,286	28,286
29.	A/C 512	4,763,936	4,083,709	4,083,709
30.	A/C 513	6,184,656	5,651,427	5,651,427
31.	A/C 514	2,334,541	2,440,205	2,440,205
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	51,049	54,386	54,386
34.	A/C 552	27,641	3,191,684	3,191,684
35.	A/C 553	1,384,550	1,761,345	1,761,345
36.	A/C 554	175,654	181,696	181,696
37.	TRANSMISSION	13,624	14,150	14,150
38.	GENERAL PLANT	304,878	400,471	400,471
39.	TOTAL MAINTENANCE	$ 16,569,736	$ 19,194,773	$ 19,194,773

Arizona Electric Power Cooperative, Inc.

Projected Income Statement - Present and Proposed Rates

LINE NO.		-ACTUAL- TESTYEAR 3/31/2009	-PROJECTED YEAR- PRESENT RATES 3/31/2009 (a)	PROPOSED RATES 3/31/2009
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 7,883,883	$ 8,348,168	$ 8,348,168
41.	ACC GROSS REVENUE TAXES	-	-	-
42.	TAXES	-	2,933,343	2,933,343
43.	TOTAL OTHER	7,883,883	11,281,511	11,281,511
44.	TOTAL OPERATING EXPENSES (b)	183,767,165	167,427,737	167,427,737
45.	ELECTRIC OPERATING MARGINS (b)	26,214,619	11,334,942	15,357,962
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	10,580,757	10,812,194	10,812,194
47.	INTEREST CHARGES TO CONSTR	(187,816)	(187,816)	(187,816)
48.	OTHER INTEREST EXPENSE	781,804	1,142,274	1,142,274
49.	OTHER DEDUCTIONS	151,174	151,174	151,174
50.	TOTAL INTEREST & OTHER DEDUCTIONS (b)	11,325,919	11,917,826	11,917,826
51.	OPERATING MARGINS	14,888,700	(582,884)	3,440,136
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	546,419	546,419	546,419
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	398,896	565,736	565,736
55.	TOTAL OTHER NON OPERATING INCOME (b)	945,315	1,112,155	1,112,155
55a.	EXTRAORDINARY ITEMS (b)	-	-	-
56.	NET INCOME (MARGINS) (b)	$ 15,834,015	$ 529,271	$ 4,552,291

SUPPORTING SCHEDULES:
(a) C-1, *PAGES 3 & 4*

RECAP SCHEDULES:
(b) A-2

Arizona Electric Power Cooperative, Inc.

SCHEDULE F-2
10/1/2009

Projected Changes in Financial Position
Present and Proposed Rates

LINE NO.		ACTUAL TESTYEAR ENDED 3/31/2009 (a)	PROJECTED YEAR PRESENT RATES ENDED 3/31/2009 (b)	PROJECTED YEAR PROPOSED RATES ENDED 3/31/2009 (b)
1.	NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 13,616,330	$ 905,169	$ 4,928,189
2.	NET CASH USED IN INVESTING ACTIVITIES	(29,201,380)	(29,201,380)	(29,201,380)
3.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	7,972,352	7,972,352	7,972,352
4.	NET DECREASE IN CASH AND CASH EQ.	$ (7,612,698)	$ (20,323,859)	$ (16,300,839)

SUPPORTING SCHEDULES:
(a) E-3

RECAP SCHEDULES:
(b) A-5

Arizona Electric Power Cooperative, Inc.

Projected Construction Requirements

SCHEDULE F-3
10/1/2009

LINE NO.		-ACTUAL- TESTYEAR ENDED 3/31/2009	-PROJECTED YEAR- YEAR ENDED 3/31/2010	YEAR ENDED 3/31/2011	YEAR ENDED 3/31/2012
1.	PRODUCTION PLANT	$ 22,230,312	$ 19,617,100	$ 34,783,500	$ 29,192,000
2.	TRANSMISSION PLANT	-	-	-	-
3.	GENERAL PLANT	83,749	496,670	511,570	526,927
4.	HEADQUARTERS BULDING	-	-	-	-
5.	RETIREMENTS	3,302,791	-	-	-
6.	TOTAL PLANT (a)	$ 25,616,852	$ 20,113,770	$ 35,295,070	$ 29,718,927

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) A-4

Arizona Electric Power Cooperative, Inc.

Assumptions Used in Developing Projections

SCHEDULE F-4
10/1/2009

LINE NO.		
1.	DSCR GOAL	1.35
2.	COAL	$3.01 $/MMBtu
3.	GAS	$8.00/MCF
	PURCHASED POWER:	
4.	CRSP	$7.76/KW + $.010560/KWH
5.	SOUTHPOINT (May - Oct)	$8.55/KW + $0.07592/KWH
6.	GRIFFITH	$7.35/KW + $0.08220/KWH
7.	PARKER DAVIS (Jan-Sept)	$1.46/KW + $0.00790/KWH
8.	PARKER DAVIS (Oct-Dec)	$1.48/KW + $0.00798/KWH
9.	POWEREX	$0.08904/KWH
10.	ECONOMY	$0.09036/KWH
11.	FFB INTEREST RATE	4.5000%
12.	S-T INVESTMENT INTEREST	2.4500%
13.	STAFFING LEVELS	299
14.	PROPERTY TAXES	$3,300,627
	DEPRECIATION RATES:	
15.	STEAM UNITS	
	ST 1	3.10%
	ST 2	2.09%
	ST 3	1.81%
16.	COMBUSTION TURBINES	3.00%
17.	HEADQUARTERS	2.00%
18.	GENERAL PLANT	6.00%
19.	VEHICLES	3-10 YEARS MINUS SALVAGE
20.	COMMUNICATIONS	6.00%
21.	SYS. CONTROL & MICROWAVE	6.00%

G

Arizona Electric Power Cooperative, Inc.
COST OF SERVICE SUMMARY - PRESENT RATES

LINE NO.	DESCRIPTION	TOTAL AEPCO
1	REVENUES:	
2	MEMBERS (a)	$166,618,638
3	NON-MEMBERS (b)	8,620,097
4	OTHER OPERATING REVENUE (b)	3,523,943
5	TOTAL REVENUES	$178,762,678
6	OPERATING EXPENSES (c)	167,427,738
7	ELECTRIC OPERATING MARGINS	$11,334,940
8	INCOME TAXES	0
9	RETURN (MARGINS) (LINE 7 - LINE 8)	$11,334,940
10		
11	RATE BASE (d)	$ 231,844,975
12	RATE OF RETURN	4.89%
13		
14		
15	SUPPORTING SCHEDULES:	
16	(a) H-1, LINE 1	
17	(b) C-1, PAGE 3, LINES 3 AND 5	
18	(c) G-6, PAGE 1, LINE 50 AND C-1, PAGE 4, LINE 44	
19	(d) B-1, LINE 9	

Arizona Electric Power Cooperative, Inc.
COST OF SERVICE SUMMARY - PROPOSED RATES

LINE NO.	DESCRIPTION	TOTAL AEPCO
1	**REVENUES:**	
2	**MEMBERS (a)**	$170,641,659
3	**NON-MEMBERS (b)**	8,620,097
4	**OTHER OPERATING REVENUE (b)**	3,523,943
5	**TOTAL REVENUES**	$182,785,699
6	**OPERATING EXPENSES (c)**	167,427,738
7	**ELECTRIC OPERATING MARGINS**	$15,357,961
8	**INCOME TAXES**	0
9	**RETURN (MARGINS) (LINE 6 - LINE 7)**	$15,357,961
10		
11	**RATE BASE (d)**	$ 231,844,975
12	**RATE OF RETURN**	6.62%
13		
14		
15	SUPPORTING SCHEDULES:	
16	(a) H-1, LINE 1	
17	(b) C-1, PAGE 3, LINES 3 AND 5	
18	(c) G-6, PAGE 1, LINE 50 AND C-1, PAGE 4, LINE 44	
19	(d) B-1, LINE 9	

Arizona Electric Power Cooperative, Inc.

DERIVATION OF PROPOSED RATES

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1					
2	SEE SCHEDULE G-4, PAGE 1 OF 2				

Arizona Electric Power Cooperative, Inc.
RATE BASE ALLOCATION TO CLASSES OF SERVICE

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1					
2	THIS SCHEDULE IS NOT APPLICABLE				

Arizona Electric Power Cooperative, Inc.
DERIVATION OF REVENUE REQUIREMENTS AND RATES

LINE NO.	FUNCTIONAL COSTS	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1	REVENUE REQUIREMENT DEVELOPMENT				
2	FIXED COSTS				
3	BASE RESOURCES	$7,188,562	$6,365,291	$6,525,929	$20,079,781
4	OTHER EXISTING RESOURCES	2,079,946	1,841,740	1,888,219	5,809,905
5	ADDITIONAL ARM RESOURCES	0	0	2,689,474	2,689,474
6	SUB-TOTAL	$9,268,508	$8,207,031	$11,103,622	$28,579,161
7					
8	O&M				
9	BASE RESOURCES	$14,205,355	$12,578,484	$12,895,922	$39,679,761
10	OTHER EXISTING RESOURCES	2,717,800	2,406,544	2,467,277	7,591,621
11	ADDITIONAL ARM RESOURCES	0	0	(618,710)	(618,710)
12	SUB-TOTAL	$16,923,155	$14,985,028	$14,744,489	$46,652,672
13					
14	ENERGY				
15	BASE RESOURCES	$25,235,851	$23,844,840	$24,585,138	$73,665,829
16	OTHER EXISTING RESOURCES	6,237,567	7,259,986	8,011,534	21,509,087
17	ADDITIONAL ARM RESOURCES	0	0	234,910	234,910
18	SUB-TOTAL	$31,473,418	$31,104,826	$32,831,581	$95,409,826
19					
20	TOTAL RESOURCE COSTS				
21	BASE RESOURCES	$46,629,767	$42,788,615	$44,006,989	$133,425,371
22	OTHER EXISTING RESOURCES	11,035,314	11,508,270	12,367,030	34,910,613
23	ADDITIONAL ARM RESOURCES	0	0	2,305,674	2,305,674
24	SUB-TOTAL	$57,665,081	$54,296,885	$58,679,693	$170,641,659
25					
26					
27	RATE DEVELOPMENT				
28	BILLING DETERMINANTS				
29	BILLING DEMANDS	1,723,369	1,629,806	1,839,465	5,192,640
30	BASE RESOURCE KWH	784,700,545	738,282,902	759,805,654	2,282,789,101
31	OTHER EXISTING RESOURCES KWH	90,679,515	108,755,098	119,040,065	318,474,678
32	ADDITIONAL ARM RESOURCES KWH	0	0	3,200,000	3,200,000
33	TOTAL KWH	875,380,060	847,038,000	882,045,719	2,604,463,779
34					
35	MONTHLY CHARGES				
36	FIXED CHARGE	$772,376	$683,919	$6.036	$5.504
37	O&M CHARGE	$1,410,263	$1,248,752	$8.016	$8.984
38	BASE ENERGY CHARGE	$0.03216	$0.03230	$0.03236	$0.03227
39	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.06879	$0.06676	$0.06730	$0.06754
40	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	$0.07341	$0.07341
41	AVERAGE ENERGY CHARGE	$0.035954	$0.036722	$0.037222	$0.036633

Arizona Electric Power Cooperative, Inc.
ASSIGNMENT OF BASE AND OTHER ENERGY RESOURCE COSTS AND CREDITS

BASE RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	ENERGY	MEC	SSVEC	ARM
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	COAL COSTS FOR TARIFF LOAD	$19,329,841	$6,678,640	$6,187,018	$6,464,183
4	COAL COSTS FOR RESOURCE TRANSFERS	1,145,169	398,862	269,962	476,345
5	COAL COSTS FOR THIRD PARTY SALES	2,507,121	1,199,603	705,665	601,853
6	RESOURCE TRANSFER CREDITS	(1,699,172)	(572,118)	(405,130)	(721,924)
7	SUB-TOTAL	$21,282,959	$7,704,987	$6,757,515	$6,820,457
8					
9	BASE COST BEFORE ADJUSTMENTS	56,632,134	19,467,093	18,315,549	18,849,492
10					
11	PRODUCTION - FUEL A/C 501	$77,915,093	$27,172,080	$25,073,064	$25,669,949
12					
13	ADJUSTMENTS				
14	PURCHASED POWER ACCOUNT 555 - ENERGY	1,701,090	584,744	550,154	566,192
15	TRANSMISSION OF ELEC BY OTHERS ACCOUNT 565 - ENERGY	2,880	990	932	959
16	FIRM CONTRACT REVENUES	(2,448,992)	(841,832)	(792,035)	(815,125)
17	BASE RESOURCE ECONOMY ENERGY	(3,504,243)	(1,680,130)	(987,275)	(836,838)
18	SCHEDULING REVENUES	0	0	0	0
19	OTHER OPERATING REVENUES	0	0	0	0
20	TOTAL NET BASE RESOURCES ENERGY REVENUE REQUIREMENTS	$73,665,829	$25,235,851	$23,844,840	$24,585,138
21					
22					

LINE NO.	OTHER RESOURCE ENERGY COSTS AND CREDITS				
23					
24	DESCRIPTION	ENERGY	MEC	SSVEC	ARM
25	OTHER EXISTING RESOURCE COSTS	$21,509,087	$6,237,567	$7,259,986	$8,011,534
26	RESOURCE TRANSFER COSTS	1,699,172	272,834	749,346	676,992
27	OTHER RESOURCE COSTS	$19,809,915	$5,964,733	$6,510,640	$7,334,542
28					
29	RESOURCE TRANSFER KWH	35,966,376	5,616,722	15,907,156	14,442,498
30	OTHER RESOURCE KWH	282,508,302	85,062,793	92,847,942	104,597,567
31	TOTAL OTHER EXISTING RESOURCE KWH	318,474,678	90,679,515	108,755,098	119,040,065

Arizona Electric Power Cooperative, Inc.

DISTRIBUTION OF RATE BASE BY FUNCTION

LINE NO.	DESCRIPTION	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES	TOTAL AEPCO
1					
2	THIS SCHEDULE IS NOT APPLICABLE				

Arizona Electric Power Cooperative, Inc.

Distribution of Expenses by Resource
(Reclassifications and Pro Forma Adjustments Included)

LINE NO.		TOTAL ADJUSTED O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$77,934,468	$77,934,468	$0	$0
4	PRODUCTION - FUEL A/C 547	10,574,530	0	10,574,530	0
5	PRODUCTION - STEAM A/C 500	6,351,536	6,351,536	0	0
6	A/C 502	3,927,597	3,927,597	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	876,286	876,286	0	0
10	A/C 506 & 509	1,104,675	1,104,675	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	248,874	0	248,874	0
14	A/C 548	199,187	0	199,187	0
15	A/C 549	39,964	0	39,964	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY	0	0	0	0
18	- DEMAND A/C 555	3,117,006	751,678	0	2,365,328
19	- ENERGY A/C 555	13,428,376	1,701,090	11,492,376	234,910
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	2,591,247	2,271,204	316,858	3,184
22	A/C 557	0	0	0	0
23	TRANSMISSION				
24	A/C 562	819	699	119	0
25	A/C 564	77	65	11	0
26	A/C 565	4,501,921	3,200,940	1,138,980	162,000
27	ADMINISTRATIVE & GENERAL	12,054,892	11,169,203	881,345	4,343
28	TOTAL OPERATIONS	$136,951,454	$109,289,444	$24,892,245	$2,769,765
29					
30	PRODUCTION - STEAM - A/C 510	$1,387,414	$1,387,414	$0	$0
31	A/C 511	28,286	28,286	0	0
32	A/C 512	4,083,709	4,083,709	0	0
33	A/C 513	5,651,427	5,651,427	0	0
34	A/C 514	2,440,204	2,440,204	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	54,386	0	54,386	0
37	A/C 552	3,191,684	0	3,191,684	0
38	A/C 553	1,761,345	0	1,761,345	0
39	A/C 554.	181,696	0	181,696	0
40	TRANSMISSION				
41	A/C 570	14,150	12,087	2,063	0
42	GENERAL PLANT	400,471	371,851	28,563	57
43	TOTAL MAINTENANCE	$19,194,773	$13,974,979	$5,219,737	$57
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$8,348,168	$6,353,076	$1,994,833	$258
47	TAXES	2,933,343	2,617,177	316,166	0
48	TOTAL OTHER	$11,281,511	$8,970,253	$2,310,999	$258
49					
50	TOTAL OPERATING EXPENSES	$167,427,738	$132,234,676	$32,422,982	$2,770,080
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$10,812,194	$8,158,153	$2,653,949	$93
54	INT. CHARGES TO CONST.	(187,816)	(141,713)	(46,101)	(2)
55	OTHER INT. EXPENSE	1,142,274	924,605	217,611	58
56	OTHER DEDUCTIONS	151,174	114,066	37,107	1
57	TOTAL INT. & OTHER DED.	$11,917,826	$9,055,110	$2,862,565	$150
58					
59	TOTAL EXPENSES	$ 179,345,564	$ 141,289,787	$ 35,285,547	$ 2,770,230
60					
61					
62					

63 SUPPORTING SCHEDULES:
64 (a) C-1, PAGES 3 AND 4
65 (b) C-1, PAGE 4, LINES 44 + 50

Arizona Electric Power Cooperative, Inc.
Distribution of Booked Expenses by Resource

LINE NO.		TOTAL BOOKED O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$61,965,748	$61,965,748	$0	$0
4	PRODUCTION - FUEL A/C 547	10,574,530	0	10,574,530	0
5	PRODUCTION - STEAM A/C 500	5,997,229	5,997,229	0	0
6	A/C 502	2,795,766	2,795,766	0	0
7	A/C 503	0		0	0
8	A/C 504	0		0	0
9	A/C 505	1,385,698	1,385,698	0	0
10	A/C 506 & 509	1,083,857	1,083,857	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	234,983	0	234,983	0
14	A/C 548	707,145	0	707,145	0
15	A/C 549	39,148	0	39,148	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	6,274,506	751,678	2,925,000	2,597,828
19	- ENERGY A/C 555	35,795,431	1,701,090	30,545,119	3,549,222
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	3,315,542	2,906,043	405,426	4,074
22	A/C 557	1,548,021	1,356,826	189,293	1,902
23	TRANSMISSION				
24	A/C 562	819	699	119	0
25	A/C 564	77	65	11	0
26	A/C 565	16,345,082	14,201,775	1,981,307	162,000
27	ADMINISTRATIVE & GENERAL	11,249,966	10,445,976	802,390	1,600
28	TOTAL OPERATIONS	$159,313,547	$104,592,451	$48,404,471	$6,316,625
29					
30	PRODUCTION - STEAM - A/C 510	$1,302,263	$1,302,263	$0	$0
31	A/C 511	26,944	26,944	0	0
32	A/C 512	4,763,936	4,763,936	0	0
33	A/C 513	6,184,656	6,184,656	0	0
34	A/C 514	2,334,541	2,334,541	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	51,049	0	51,049	0
37	A/C 552	27,641	0	27,641	0
38	A/C 553	1,384,550	0	1,384,550	0
39	A/C 554.	175,654	0	175,654	0
40	TRANSMISSION				
41	A/C 570	13,624	11,638	1,986	0
42	GENERAL PLANT	304,878	283,090	21,745	43
43	TOTAL MAINTENANCE	$16,569,736	$14,907,068	$1,662,625	$43
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$7,883,883	$5,921,972	$1,961,719	$192
47	TAXES	0	0	0	0
48	TOTAL OTHER	$7,883,883	$5,921,972	$1,961,719	$192
49					
50	TOTAL OPERATING EXPENSES	$183,767,166	$125,421,490	$52,028,814	$6,316,861
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$10,580,757	$7,983,526	$2,597,140	$91
54	INT. CHARGES TO CONST.	(187,816)	(141,713)	(46,101)	(2)
55	OTHER INT. EXPENSE	781,804	589,897	191,901	7
56	OTHER DEDUCTIONS	151,174	114,066	37,107	1
57	TOTAL INT. & OTHER DED.	$11,325,919	$8,545,775	$2,780,047	$97
58					
59	TOTAL EXPENSES	$ 195,093,084	$ 133,967,265	$ 54,808,861	$ 6,316,958
60					
61					
62					

63 SUPPORTING SCHEDULES:
64 (a) C-1, PAGES 1 AND 2
65 (b) C-1, PAGE 2, LINES 44 + 50

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource

LINE NO.		ADJUSTMENTS TO *O&M EXPENSES (a)*	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$16,520,095	$16,520,095	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0
5	PRODUCTION - STEAM A/C 500	354,307	354,307	0	0
6	A/C 502	2,839,931	2,839,931	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	0	0	0	0
10	A/C 506 & 509	20,818	20,818	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	13,891	0	13,891	0
14	A/C 548	1,405	0	1,405	0
15	A/C 549	816	0	816	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	(3,157,500)	0	(2,925,000)	(232,500)
19	- ENERGY A/C 555	(22,367,055)	0	(19,052,743)	(3,314,312)
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	109,150	95,669	13,347	134
22	A/C 557	0	0	0	0
23	TRANSMISSION				
24	A/C 562	0	0	0	0
25	A/C 564	0	0	0	0
26	A/C 565	(4,963,137)	(4,963,137)	0	0
27	ADMINISTRATIVE & GENERAL	540,635	477,825	60,105	2,706
28	TOTAL OPERATIONS	($10,086,643)	$15,345,509	($21,888,180)	($3,543,972)
29					
30	PRODUCTION - STEAM - A/C 510	$85,151	$85,151	$0	$0
31	A/C 511	1,342	1,342	0	0
32	A/C 512	(680,227)	(680,227)	0	0
33	A/C 513	(533,229)	(533,229)	0	0
34	A/C 514	105,663	105,663	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	3,337	0	3,337	0
37	A/C 552	3,164,043	0	3,164,043	0
38	A/C 553	376,795	0	376,795	0
39	A/C 554.	6,042	0	6,042	0
40	TRANSMISSION				
41	A/C 570	526	449	77	0
42	GENERAL PLANT	95,593	88,761	6,818	14
43	TOTAL MAINTENANCE	$2,625,037	($932,089)	$3,557,112	$14
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$464,285	$431,104	$33,115	$66
47	TAXES	0	0	0	0
48	TOTAL OTHER	$464,285	$431,104	$33,115	$66
49					
50	TOTAL OPERATING EXPENSES	($6,997,321)	$14,844,525	($18,297,953)	($3,543,892)
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$231,437	$174,627	$56,808	$2
54	INT. CHARGES TO CONST.	0	0	0	0
55	OTHER INT. EXPENSE	360,470	334,709	25,710	51
56	OTHER DEDUCTIONS	0	0	0	0
57	TOTAL INT. & OTHER DED.	$591,907	$509,335	$82,518	$53
58					
59	TOTAL EXPENSES	($6,405,414)	$15,353,860	($18,215,434)	($3,543,839)
60					
61					
62					

63 SUPPORTING SCHEDULES:
64 (a) C-1, PAGES 3 & 4
65 (b) C-1, PAGE 4, LINES 44 + 50

Arizona Electric Power Cooperative, Inc.

Distribution of Expense Reclassifications by Resource

LINE NO.		*RECLASSIFICATIONS OF O&M EXPENSES*	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	($551,375)	($551,375)	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0
5	PRODUCTION - STEAM A/C 500	0	0	0	0
6	A/C 502	(1,708,100)	(1,708,100)	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	(509,412)	(509,412)	0	0
10	A/C 506 & 509	0	0	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0
14	A/C 548	(509,363)	0	(509,363)	0
15	A/C 549	0	0	0	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	0	0		
19	- ENERGY A/C 555	0	0	0	0
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	(833,446)	(730,508)	(101,914)	(1,024)
22	A/C 557	(1,548,021)	(1356826)	(189293)	(1902)
23	TRANSMISSION				
24	A/C 562	0	0	0	0
25	A/C 564	0	0	0	0
26	A/C 565	(6,880,024)	(6,037,697)	(842,327)	0
27	ADMINISTRATIVE & GENERAL	264,291	245,403	18,850	38
28	TOTAL OPERATIONS	($12,275,450)	($10,648,516)	($1,624,046)	($2,888)
29					
30	PRODUCTION - STEAM - A/C 510	$0	$0	$0	$0
31	A/C 511	0	0	0	0
32	A/C 512	0	0	0	0
33	A/C 513	0	0	0	0
34	A/C 514	0	0	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0
37	A/C 552	0	0	0	0
38	A/C 553	0	0	0	0
39	A/C 554.	0	0	0	0
40	TRANSMISSION				
41	A/C 570	0	0	0	0
42	GENERAL PLANT	0	0	0	0
43	TOTAL MAINTENANCE	$0	$0	$0	$0
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$0	$0	$0	$0
47	TAXES	2,933,343	2,617,177	316,166	0
48	TOTAL OTHER	$2,933,343	$2,617,177	$316,166	$0
49					
50	TOTAL OPERATING EXPENSES	($9,342,107)	($8,031,339)	($1,307,880)	($2,888)
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$0	$0	$0	$0
54	INT. CHARGES TO CONST.	0	0	0	0
55	OTHER INT. EXPENSE	0	0	0	0
56	OTHER DEDUCTIONS	0	0	0	0
57	TOTAL INT. & OTHER DED.	$0	$0	$0	$0
58					
59	TOTAL EXPENSES	($9,342,107)	($8,031,339)	($1,307,880)	($2,888)
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-2, PAGES 1 & 2				
65	(b) C-2, PAGE 2, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Class A Member Revenue Requirements by Function

LINE NO.		BASE RESOURCES			OTHER EXISTING RESOURCES			ADDITIONAL ARM RESOURCES			TOTAL AEPCO REVENUE REQUIREMENT			
		FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	Total
1	OPERATING EXPENSES:													
2	OPERATIONS													
3	PRODUCTION - FUEL A/C 501	$19,375	$0	$77,915,093	$0	$0	$0	$0	$0	$0	$19,375	$0	$77,915,093	$77,934,468
4	PRODUCTION - FUEL A/C 547	0	0	0	109,790	0	10,464,740	0	0	0	109,790	0	10,464,740	10,574,530
5	PRODUCTION - STEAM A/C 500	0	6,351,536	0	0	0	0	0	0	0	0	6,351,536	0	6,351,536
6	A/C 502	1,145,813	2,781,784	0	0	0	0	0	0	0	1,145,813	2,781,784	0	3,927,597
7	A/C 503	0	0	0	0	0	0	0	0	0	0	0	0	0
8	A/C 504	0	0	0	0	0	0	0	0	0	0	0	0	0
9	A/C 505	92,400	783,886	0	0	0	0	0	0	0	92,400	783,886	0	876,286
10	A/C 506 & 509	0	1,104,675	0	0	0	0	0	0	0	0	1,104,675	0	1,104,675
11	A/C 507	0	0	0	0	0	0	0	0	0	0	0	0	0
12	A/C 508	0	0	0	0	0	0	0	0	0	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0	248,874	0	0	0	0	0	248,874	0	248,874
14	A/C 548	0	0	0	79,166	120,021	0	0	0	0	79,166	120,021	0	199,187
15	A/C 549	0	0	0	0	39,964	0	0	0	0	0	39,964	0	39,964
16	A/C 550	0	0	0	0	0	0	0	0	0	0	0	0	0
17	OTHER POWER SUPPLY													
18	- DEMAND A/C 555	751,678	0	0	0	0	0	2,365,328	0	0	3,117,006	0	0	3,117,006
19	- ENERGY A/C 555	0		1,701,090	0	0	11,492,376	0	0	234,910	0	0	13,428,376	13,428,376
20	- INDIRECT A/C 555	0	0	0	0	0	0	0	0	0	0	0	0	0
21	A/C 556	0	2,271,204	0	0	316,858	0	0	3,184	0	0	2,591,247	0	2,591,247
22	A/C 557	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TRANSMISSION													
24	A/C 562	0	699	0	0	119	0	0	0	0	0	819	0	819
25	A/C 564	0	65	0	0	11	0	0	0	0	0	77	0	77
26	A/C 565	0	3,198,060	2,880	0	1,338,980	0	0	162,000	0	0	4,499,040	2,880	4,501,921
27	ADMINISTRATIVE & GENERAL	0	11,169,203	0		881,345	0	0	4,343	0	0	12,054,892	0	12,054,892
28	TOTAL OPERATIONS	$2,009,266	$27,661,115	$79,619,064	$188,956	$2,746,173	$21,957,116	$2,365,328	$169,527	$234,910	$4,563,549	$30,576,815	$101,811,090	$136,951,454
29														
30	PRODUCTION - STEAM - A/C 510	0	1,387,414	0	0	0	0	0	0	0	0	1,387,414	0	1,387,414
31	A/C 511	0	28,286	0	0	0	0	0	0	0	0	28,286	0	28,286
32	A/C 512	0	4,083,709	0	0	0	0	0	0	0	0	4,083,709	0	4,083,709
33	A/C 513	0	5,651,427	0	0	0	0	0	0	0	0	5,651,427	0	5,651,427
34	A/C 514	0	2,440,204	0	0	0	0	0	0	0	0	2,440,204	0	2,440,204
35	A/C 515.	0	0	0	0	0	0	0	0	0	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0	54,386	0	0	0	0	0	54,386	0	54,386
37	A/C 552	0	0	0	0	3,191,684	0	0	0	0	0	3,191,684	0	3,191,684
38	A/C 553	0	0	0	0	1,761,345	0	0	0	0	0	1,761,345	0	1,761,345
39	A/C 554.	0	0	0	0	181,696	0	0	0	0	0	181,696	0	181,696
40	TRANSMISSION													
41	A/C 570	0	12,087	0	0	2,063	0	0	0	0	0	14,150	0	14,150
42	GENERAL PLANT	0	371,851	0	0	28,563	0	0	57	0	0	400,471	0	400,471
43	TOTAL MAINTENANCE	$0	$13,974,979	$0	$0	$5,219,737	$0	$0	$57	$0	$0	$19,194,773	$0	$19,194,773
44														
45	OTHER:													
46	DEPRECIATION & AMORTIZATION	$6,353,076	$0	$0	$1,994,833	$0	$0	$258	$0	$0	8,348,168	0	0	8,348,168
47	TAXES	2,617,177	0	0	316,166	0	0	0	0	0	2,933,343	0	0	2,933,343
48	TOTAL OTHER	$8,970,253	$0	$0	$2,310,999	$0	$0	$258	$0	$0	$11,281,511	$0	$0	$11,281,511
49														
50	TOTAL OPERATING EXPENSES	$10,979,519	$41,636,093	$79,619,064	$2,499,955	$7,965,911	$21,957,116	$2,365,586	$169,584	$234,910	$15,845,060	$49,771,588	$101,811,090	$167,427,738
51														
52	INT. & OTHER DEDUCTIONS:													
53	INT. ON LONG-TERM DEBT	$8,158,153	$0	$0	$2,653,949	$0	$0	$93	$0	$0	$10,812,194	$0	$0	$10,812,194
54	INT. CHARGES TO CONST.	(141,713)	0	0	(46,101)	0	0	(2)	0	0	(187,816)	0	0	(187,816)
55	OTHER INT. EXPENSE	924,605	0	0	217,611	0	0	58	0	0	1,142,274	0	0	1,142,274
56	OTHER DEDUCTIONS	114,066	0	0	37,107	0	0	1	0	0	151,174	0	0	151,174
57	TOTAL INT. & OTHER DED.	$9,055,110	$0	$0	$2,862,565	$0	$0	$150	$0	$0	$11,917,826	$0	$0	$11,917,826
58														
59	TOTAL EXPENSES	$20,034,630	$41,636,093	$79,619,064	$5,362,520	$7,965,911	$21,957,116	$2,365,736	$169,584	$234,910	$27,762,886	$49,771,588	$101,811,090	$179,345,564
60														
61	REVENUE CREDITS													
62	FIRM CONTRACT REVENUES	$1,430,539	$0	$2,448,992	$0	$0	$0	$0	$0	$0	$1,430,539	$0	$2,448,992	$3,879,531
63	ECONOMY ENERGY	0	0	3,504,243	0	0	448,029	0	0	0	0	0	3,952,272	3,952,272
64	SCHEDULING REVENUES (all to ARMs)	0	0	0	0	0	0	0	788,294	0	0	788,294	0	788,294
65	OTHER OPERATING REVENUES	941,356	1,956,332	0	251,966	374,290	0	0	0	0	1,193,322	2,330,622	0	3,523,943
66	TOTAL REVENUE CREDITS	$2,371,895	$1,956,332	$5,953,235	$251,966	$374,290	$448,029	$0	$788,294	$0	$2,623,861	$3,118,916	$6,401,264	$12,144,040
67														
68	MARGINS	2,417,046	0	0	699,351	0	0	323,738	0	0	3,440,135	0	0	3,440,135
69														
70	CLASS A MEMBER REVENUE REQUIREMENTS	$ 20,079,781	$ 39,679,761	$ 73,665,829	$ 5,809,905	$ 7,591,621	$ 21,509,087	$ 2,689,474	($618,710)	$ 234,910	$ 28,579,161	$ 46,652,672	$ 95,409,826	$ 170,641,659

Arizona Electric Power Cooperative, Inc.

DERIVATION OF ALLOCATION FACTORS

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1	**ALLOCATION FACTORS**				
2	ENERGY ALLOCATION FACTORS				
3	BASE RESOURCE KWH	784,700,545	738,282,902	759,805,654	2,282,789,101
4	OTHER EXISTING RESOURCES KWH	90,679,515	108,755,098	119,040,065	318,474,678
5	ADDITIONAL ARM RESOURCES KWH	0	0	3,200,000	3,200,000
6					
7	BASE RESOURCE KWH	34.375%	32.341%	33.284%	100.000%
8	OTHER EXISTING RESOURCES KWH	28.473%	34.149%	37.378%	100.000%
9	ADDITIONAL ARM RESOURCES KWH	0.000%	0.000%	100.000%	100.000%
10					
11	FIXED COST ALLOCATION FACTORS				
12	ACP	35.800%	31.700%	32.500%	100.000%
13					
14					
15	**FUNCTIONALIZATION FACTORS**	**BASE RESOURCES**	**OTHER EXISTING RESOURCES**	**ADDITIONAL ARM RESOURCES**	**TOTAL AEPC**
16	DISPATCHED ENERGY (KWH)	2,282,789,101	318,474,678	3,200,000	2,604,463,779
17	DISPATCHED ENERGY (%)	87.649%	12.228%	0.123%	100.000%
18					
19	SUB-TOTAL PURCHASED POWER				
20	PRODUCTION - FUEL A/C 501	$61,965,748	$0	$0	$61,965,748
21	*PRODUCTION - FUEL A/C 547*	0	10,574,530	0	10574530.1
22	SUBTOTAL ($)	$61,965,748	$10,574,530	$0	$72,540,278
23	SUBTOTAL (%)	85.423%	14.577%	0.000%	100.000%
24					
25	PAYROLL EXCLUDING A&G AND GEN PLT MNTC ($)	$10,961,004	$841,952	$1,589	$11,804,545
26	PAYROLL EXCLUDING A&G AND GEN PLT MNTC (%)	92.854%	7.132%	0.013%	100.000%
27					
28	INTEREST ON LONG TERM DEBT ($)	$7,983,526	$2,597,140	$91	$10,580,757
29	INTEREST ON LONG TERM DEBT (%)	75.453%	24.546%	0.001%	100.000%
30					
31	TOTAL EXPENSES LESS A&G ($)	$130,120,583	$34,404,201	$2,765,887	$167,290,671
32	TOTAL EXPENSES LESS A&G (%)	77.781%	20.566%	1.653%	100.000%
33					
34	A&G EXPENSES ($)	$11,249,966	$10,445,976	$1,600	$21,697,542
35	A&G EXPENSES (%)	51.849%	48.144%	*0.007%*	*100.000%*

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Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class
March 31, 2009 Adjusted Test Year

Line No.	CLASS OF SERVICE	PRESENT	PROPOSED	AMOUNT	PERCENT
1	Total Class A Member Revenues	$166,618,638	$170,641,659	$4,023,020	2.41%
2	Non-Members	8,620,097	8,620,097	0	0.00%
3	Other Operating Revenues	3,523,943	3,523,943	0	0.00%
4	Total AEPCO	$178,762,678	$182,785,699	$4,023,020	2.25%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class
March 31, 2009 Adjusted Test Year

Line No.	CLASS OF SERVICE	CUSTOMERS	KWH CONSUMPTION	BILLING KW	REVENUE PRESENT	REVENUE PROPOSED	PROPOSED INCREASE ($)	PROPOSED INCREASE (%)
1	Member Contracts:							
2	Anza	1	51,283,408	96,412	$3,353,127	$3,255,189	($97,938)	-2.92%
3	Duncan	1	28,079,760	57,180	1,901,744	1,847,503	(54,241)	-2.85%
4	Graham	1	156,396,015	324,562	10,683,325	10,404,440	(278,884)	-2.61%
5	Mohave	1	784,700,545	1,723,399	54,205,506	57,665,081	3,459,575	6.38%
6	Sulphur	1	738,282,902	1,629,806	52,026,365	54,296,885	2,270,519	4.36%
7	*Trico*	1	646,286,536	1,361,311	44,448,572	43,172,561	(1,276,011)	-2.87%
8	Total Class A Members	6	2,405,029,166	5,192,670	$166,618,638	$170,641,659	$4,023,020	2.41%
9								
10	Other Firm Contracts:							
11	City of Mesa	0	0	0	$0	$0	N/A	N/A
12	Salt River Project	0	0	0	0	0	N/A	N/A
13	Public Service Company of New Mexico	0	0	0	0	0	N/A	N/A
14	ED2	1	68,952,281	96,000	3,879,531	3,879,531	$0	0.00%
15	Total Firm Contracts	1	68,952,281	96,000	$3,879,531	$3,879,531	$0	0.00%
16								
17	Total AEPCO	7	2,473,981,447	5,288,670	$170,498,169	$174,521,189	$4,023,020	2.36%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.
CLASS A MEMBER BOOKED SALES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1														
2	ANZA													
3	MW	5.712	7.488	10.608	10.404	9.948	9.684	6.852	5.388	8.860	8.093	7.071	6.304	96.412
4	MWH	3,733.956	3,974.280	4,547.868	5,266.360	5,087.034	4,309.788	3,861.588	3,682.884	4,682.804	4,128.590	3,963.021	4,047.215	51,283.408
5														
6	DUNCAN													
7	MW	3.860	6.040	6.960	5.940	6.620	5.360	4.020	2.780	4.300	3.900	3.900	3.500	57.180
8	MWH	2,004.660	2,422.840	3,223.350	2,960.420	2,955.880	2,300.600	1,919.560	1,905.850	2,292.120	2,226.640	1,883.390	1,984.450	28,079.760
9														
10	GRAHAM													
11	MW	20.966	31.511	39.951	39.726	36.986	32.263	24.988	18.448	20.642	19.992	18.818	20.271	324.562
12	MWH	10,775.112	12,244.130	18,499.166	17,976.098	17,655.323	13,801.595	11,076.763	10,334.556	12,000.020	11,134.378	9,221.331	11,677.543	156,396.015
13														
14	MOHAVE													
15	MW	95.000	103.000	110.000	132.000	133.000	124.000	102.000	72.000	79.000	79.000	75.000	54.000	1,158.000
16	MWH	62,986.000	66,854.000	69,860.000	77,273.000	77,009.000	68,313.000	58,371.000	45,187.000	48,485.000	46,549.000	40,805.000	39,120.000	700,812.000
17														
18	SULPHUR													
19	MW	84.000	88.000	102.000	96.000	97.000	100.000	89.000	77.000	97.000	97.000	104.000	91.000	1,122.000
20	MWH	56,633.000	61,631.000	61,830.000	61,828.000	62,148.000	59,310.000	55,640.000	48,978.000	56,895.000	57,703.000	53,357.000	56,528.000	692,481.000
21														
22	TRICO													
23	MW	85.694	125.853	164.497	149.759	155.557	140.957	116.234	91.507	90.195	85.104	80.967	72.836	1,359.160
24	MWH	43,348.839	49,883.272	69,143.826	72,230.849	72,594.073	62,002.723	50,728.275	42,934.549	49,950.664	48,018.911	41,759.997	43,690.558	646,286.536
25														
26														
27														
28	FULL REQUIREMENTS													
29	MW	116.232	170.892	222.016	205.829	209.111	188.264	152.094	118.123	123.997	117.089	110.756	102.911	1,837.314
30	MWH	59,862.567	68,524.522	95,414.210	98,433.747	98,292.310	82,414.706	67,586.186	58,857.839	68,925.608	65,506.519	56,827.739	61,399.766	882,045.719
31														
32	PARTIAL REQUIREMENTS													
33	MW	179.000	191.000	212.000	228.000	230.000	224.000	191.000	149.000	176.000	176.000	179.000	145.000	2,280.000
34	MWH	119,619.000	128,485.000	131,690.000	139,101.000	139,157.000	127,623.000	114,011.000	94,165.000	105,380.000	104,252.000	94,162.000	95,648.000	1,393,293.000
35														
36														
37														
38	TOTAL CLASS A													
39	MW	295.232	361.892	434.016	433.829	439.111	412.264	343.094	267.123	299.997	293.089	289.756	247.911	4,146.649
40	MWH	179,481.567	197,009.522	227,104.210	237,534.747	237,449.310	210,037.706	181,597.186	153,022.839	174,305.608	169,758.519	150,989.739	157,047.766	2,346,776.427

Arizona Electric Power Cooperative, Inc.
CLASS A MEMBER ADJUSTED SALES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	MW	5.712	7.488	10.608	10.404	9.948	9.684	6.852	5.388	8.860	8.093	7.071	6.304	96.412
3	MWH	3,733.956	3,974.280	4,547.868	5,266.380	5,087.034	4,309.788	3,861.588	3,682.884	4,682.804	4,126.590	3,963.021	4,047.215	51,283.408
4														
5	DUNCAN													
6	MW	3.860	6.040	6.960	5.940	6.620	5.360	4.020	2.780	4.300	3.900	3.900	3.500	57.180
7	MWH	2,004.660	2,422.840	3,223.350	2,960.420	2,955.880	2,300.600	1,919.560	1,805.850	2,292.120	2,226.640	1,883.380	1,984.450	28,079.760
8														
9	GRAHAM													
10	MW	20.966	31.511	39.951	39.726	36.986	32.263	24.988	18.448	20.642	19.992	18.818	20.271	324.562
11	MWH	10,775.112	12,244.130	18,499.166	17,976.098	17,655.323	13,801.595	11,076.763	10,334.556	12,000.020	11,134.378	9,221.331	11,677.543	156,396.015
12														
13	MOHAVE													
14	MW	131.516	139.516	146.516	168.516	169.516	160.516	138.516	108.516	115.516	114.800	110.800	89.800	1,594.044
15	CHEMSTAR O&M ADJ	0.000	0.000	0.000	0.000	0.000	(2.270)	0.000	0.000	0.000	(2.270)	0.000	(2.270)	(6.810)
16	POWER FACTOR ADJ	0.672	0.793	1.155	0.938	0.886	0.458	0.223	0.133	0.000	0.000	0.033	0.144	5.435
17	SCHED B O&M ADJ	0.000	23.765	33.100	11.400	10.300	19.000	8.800	0.300	3.600	3.065	5.400	12.000	130.730
18	ADJ MW	132.188	164.074	180.771	180.854	180.702	177.704	147.539	108.949	119.116	115.595	116.233	99.674	1,723.399
19	ENERGY MIN ADJ	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	12.000	4.000	39.000	4.000	59.000
20	ADJUSTED MWH	77,807.200	82,169.240	84,665.830	92,587.670	92,324.240	83,134.200	73,686.240	60,008.200	63,812.240	59,870.600	52,872.800	52,441.600	875,380.060
21														
22	SULPHUR													
23	MW	116.334	120.334	134.334	128.334	129.334	132.334	121.334	109.334	129.334	128.700	135.700	122.700	1,508.106
24	POWER FACTOR ADJ	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
25	SCHED B O&M ADJ	14.800	17.600	12.700	11.400	8.400	3.600	10.800	9.000	12.200	12.000	3.000	6.200	121.700
26	ADJ MW	131.134	137.934	147.034	139.734	137.734	135.934	132.134	118.334	141.534	140.700	138.700	128.900	1,629.806
27	ENERGY MIN ADJ	0.000	0.000	3.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.000
28	ADJUSTED MWH	69,758.600	75,194.120	74,958.600	75,391.120	75,711.120	72,435.600	69,203.120	62,103.600	70,458.120	69,495.400	64,008.200	68,320.400	847,038.000
29														
30	TRICO													
31	MW	85.694	125.853	164.497	149.759	155.557	140.957	116.234	91.507	90.195	85.104	80.967	72.836	1,359.160
32	MWH	43,348.839	49,883.272	69,143.826	72,230.849	72,594.073	62,002.723	50,728.275	42,934.549	49,950.664	48,018.911	41,759.997	43,690.558	646,286.536
33														
34														
35														
36	FULL REQUIREMENTS													
37	MW	116.232	170.892	222.016	205.829	209.111	188.264	152.094	118.123	123.997	117.089	110.756	102.911	1,837.314
38	MWH	59,862.567	68,524.522	95,414.210	98,433.747	98,292.310	82,414.706	67,586.186	58,857.839	68,925.608	65,506.519	56,827.739	61,399.766	882,045.719
39										0.000		0.000	
40	PARTIAL REQUIREMENTS													
41	MW	263.322	302.008	327.805	320.588	318.436	313.638	279.673	227.283	260.650	256.295	254.933	228.574	3,353.205
42	MWH	147,565.800	157,363.360	159,624.430	167,978.790	168,035.360	155,569.800	142,889.360	122,111.800	134,270.360	129,366.000	116,881.000	120,762.000	1,722,418.060
43														
44														
45														
46	TOTAL CLASS A													
47	MW	379.554	472.900	549.821	526.417	527.547	501.902	431.767	345.406	384.647	373.384	365.689	331.485	5,190.519
48	MWH	207,428.367	225,887.882	255,038.640	266,412.537	266,327.670	237,984.506	210,475.546	180,969.639	203,195.968	194,872.519	173,708.739	182,161.766	2,604,463.779

Arizona Electric Power Cooperative, Inc.
CLASS A MEMBER ADJUSTED BILLING DETERMINANTS

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	KW	5,712	7,488	10,608	10,404	8,948	9,684	6,852	5,388	8,880	8,093	7,071	6,304	98,412
3	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
4	KWH - BASE RESOURCES	2,852,721	3,837,518	3,498,387	4,179,337	4,064,489	3,742,041	3,622,972	3,624,544	4,588,670	3,971,349	3,861,740	2,571,184	44,414,952
5	*KWH - OTHER EXISTING RESOURCES*	881,235	136,762	1,048,481	1,087,043	898,335	525,912	238,816	58,340	94,134	155,241	101,281	1,476,031	6,702,411
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	*124,210*	*41,835*	0	0	0	0	0	0	166,045
7														
8	DUNCAN													
9	KW	3,860	6,040	6,980	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
10	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
11	KWH - BASE RESOURCES	1,531,549	2,339,466	2,478,519	2,349,355	2,361,719	1,997,532	1,800,946	1,875,660	2,246,044	2,142,874	1,835,257	1,260,715	24,220,635
12	KWH - OTHER EXISTING RESOURCES	473,111	83,374	743,831	611,065	521,988	280,738	118,614	30,190	46,076	83,766	48,133	723,735	3,784,620
13	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	72,174	22,332	0	0	0	0	0	0	94,506
14														
15	GRAHAM													
16	KW	20,966	31,511	38,851	39,726	38,986	32,263	24,988	18,448	20,642	19,892	18,818	20,271	324,562
17	KWH - TOTAL	10,775,112	12,244,130	18,498,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
18	KWH - BASE RESOURCES	8,232,123	11,822,788	14,230,236	14,265,620	14,108,426	11,983,452	10,392,305	10,170,848	11,758,796	10,715,505	8,985,686	7,418,708	134,082,474
19	KWH - OTHER EXISTING RESOURCES	2,542,989	421,342	4,268,930	3,710,478	3,117,807	1,684,170	684,458	163,708	241,224	418,873	235,665	4,258,835	21,748,479
20	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	431,089	133,972	0	0	0	0	0	0	565,062
21														
22	MOHAVE													
23	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
24	KWH - TOTAL	77,807,200	82,169,240	84,665,830	92,587,870	92,324,240	83,134,200	73,686,240	60,008,200	63,812,240	59,870,600	52,872,800	52,441,600	875,380,060
25	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
26	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
27	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
28														
29	SULPHUR													
30	KW	131,134	137,834	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	136,700	128,900	1,629,806
31	KWH - TOTAL	69,758,600	75,194,120	74,958,600	75,391,120	75,711,120	72,435,600	69,203,120	62,103,600	70,458,120	69,495,400	64,008,200	68,320,400	847,038,000
32	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
33	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
34	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
35														
36	TRICO													
37	KW	85,906	125,972	164,592	149,858	155,646	141,128	118,545	91,700	90,417	85,278	81,248	73,021	1,361,311
38	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
39	KWH - BASE RESOURCES	33,118,261	48,166,700	53,187,964	57,321,553	58,001,937	53,834,841	47,593,662	42,254,430	48,946,556	46,212,451	40,692,756	27,756,481	557,087,594
40	KWH - OTHER EXISTING RESOURCES	10,230,578	1,716,572	15,955,862	14,909,296	12,819,609	7,566,021	3,134,613	680,119	1,004,108	1,806,460	1,067,241	15,934,077	86,824,555
41	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	1,772,527	601,861	0	0	0	0	0	0	2,374,388
42														
43														
44														
45	FULL REQUIREMENTS													
46	KW	116,444	171,011	222,111	205,928	209,200	188,435	152,405	116,316	124,219	117,263	111,037	103,096	1,839,465
47	KWH - TOTAL	59,862,567	68,524,522	95,414,210	98,433,747	98,292,310	82,414,706	67,586,186	58,857,839	68,925,608	65,506,519	56,827,739	61,399,766	882,045,719
48	KWH - BASE RESOURCES	45,734,653	66,166,471	73,396,106	78,115,865	78,534,571	71,557,867	63,409,885	57,925,482	67,540,066	63,042,179	55,375,419	39,007,088	759,805,654
49	KWH - OTHER EXISTING RESOURCES	14,127,914	2,358,051	22,018,104	20,317,882	17,357,739	10,056,839	4,176,301	932,357	1,385,542	2,464,340	1,452,320	22,392,678	119,040,065
50	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,400,000	800,000	0	0	0	0	0	0	3,200,000
51														
52	PARTIAL REQUIREMENTS													
53	KW	263,322	302,008	327,805	320,588	318,438	313,638	279,673	227,283	260,650	256,295	254,933	228,574	3,353,205
54	KWH - TOTAL	147,565,800	157,363,360	159,624,430	167,978,790	168,035,360	155,569,800	142,889,360	122,111,800	134,270,380	129,366,000	116,881,000	120,762,000	1,722,418,060
55	KWH - BASE RESOURCES	95,864,199	149,868,075	144,151,772	150,173,830	151,454,731	145,316,341	132,668,206	117,258,604	127,316,180	121,117,860	109,939,195	77,853,453	1,522,983,447
56	KWH - OTHER EXISTING RESOURCES	51,701,601	7,495,285	15,472,658	17,804,960	16,560,629	10,253,459	10,220,154	4,853,196	6,954,180	8,248,140	6,941,805	42,908,547	199,434,613
57	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
58														
59	TOTAL CLASS A													
60	KW	379,766	473,019	549,916	526,516	527,638	502,073	432,078	345,599	384,869	373,558	365,970	331,670	5,192,670
61	KWH - TOTAL	207,428,367	225,887,882	255,038,640	266,412,537	266,327,670	237,984,506	210,475,546	180,969,639	203,195,968	194,872,519	173,708,739	182,161,766	2,604,463,779
62	KWH - BASE RESOURCES	141,598,852	216,034,546	217,547,878	228,288,695	229,969,302	216,874,208	196,079,091	175,184,087	194,856,246	184,160,039	165,314,615	116,860,542	2,282,789,101
63	KWH - OTHER EXISTING RESOURCES	65,829,515	9,853,336	37,490,762	38,122,842	33,938,368	20,310,298	14,396,455	5,785,552	8,339,722	10,712,480	8,394,124	65,301,224	318,474,678
64	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,400,000	800,000	0	0	0	0	0	0	3,200,000

Arizona Electric Power Cooperative, Inc.
ANZA ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
3	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
4	KWH - BASE RESOURCES	2,852,721	3,837,518	3,498,387	4,179,337	4,064,489	3,742,041	3,622,972	3,624,544	4,588,670	3,971,349	3,861,740	2,571,184	44,414,952
5	KWH - OTHER EXISTING RESOURCES	881,235	136,762	1,049,481	1,087,043	898,335	525,912	238,616	58,340	94,134	155,241	101,281	1,476,031	6,702,411
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	124,210	41,835	0	0	0	0	0	0	166,045
7														
8	**PRESENT RATES**													
9	Energy & FPPCA RATES													
10	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
11	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
12	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
13														
14	**PRESENT REVENUES**													
15	Demand Revenue	$85,566	$112,170	$158,908	$155,852	$149,021	$145,066	$102,643	$80,712	$132,723	$121,233	$105,924	$94,434	$1,444,252
16	Base Energy Charge Revenue	77,405	82,387	94,277	109,172	105,454	89,342	80,051	76,346	97,075	85,544	82,153	83,899	1,063,105
17	Total Present Base Rate Revenue	$162,971	$194,557	$253,185	$265,024	$254,475	$234,408	$182,694	$157,058	$229,797	$206,777	$188,077	$178,333	$2,507,357
18	FPPCA	47,496	50,553	67,127	77,732	75,085	63,612	103,259	98,480	125,218	110,345	105,971	108,223	1,033,100
19	Total Present Revenue	$210,467	$245,110	$320,312	$342,756	$329,560	$298,021	$285,953	$255,539	$355,016	$317,122	$294,048	$286,555	$3,540,457
20														
21	**PROPOSED RATES**													
22	Fixed Demand Charge	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	
23	O&M Demand Charge	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	
24	Base Resource Energy Charge	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	
25	Other Existing Resources Energy Charge	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	
26	Additional ARM Resources	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	
27	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
28														
29	**PROPOSED REVENUES**													
30	Fixed Demand Charge Revenue	$34,480	$45,200	$64,033	$62,802	$60,049	$58,456	$41,361	$32,524	$53,482	$48,852	$42,683	$38,053	$581,975
31	O&M Demand Charge Revenue	45,785	60,021	85,030	83,395	79,740	77,623	54,923	43,188	71,019	64,871	56,679	50,531	772,804
32	Base Resource Energy Revenue	92,306	124,171	113,198	135,231	131,515	121,082	117,229	117,280	148,476	128,501	124,955	83,196	1,437,141
33	Other Existing Resources Energy Revenue	59,308	9,204	70,631	73,159	60,459	35,394	16,059	3,926	6,335	10,448	6,816	99,339	451,080
34	Additional ARM Resources	0	0	0	0	9,118	3,071	0	0	0	0	0	0	12,189
35	Total Proposed Base Rate Revenue	$231,879	$238,597	$332,892	$354,587	$340,881	$295,627	$229,572	$196,918	$279,312	$252,672	$231,133	$271,118	$3,255,189
36	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total Proposed Revenue	$231,879	$238,597	$332,892	$354,587	$340,881	$295,627	$229,572	$196,918	$279,312	$252,672	$231,133	$271,118	$3,255,189
38														
39	**PROPOSED REVENUE CHANGES**													
40	Change in Fixed and Demand Revenue	($5,301)	($6,949)	($9,845)	($9,655)	($9,232)	($8,987)	($6,359)	($5,000)	($8,222)	($7,511)	($6,562)	($5,850)	($89,473)
41	Change in Base Energy Charge Revenue	74,209	50,989	89,552	99,219	95,638	70,205	53,237	44,860	57,737	53,405	49,618	98,636	837,305
42	Change in Base Rate Revenue	$68,908	$44,039	$79,707	$89,563	$86,406	$61,218	$46,879	$39,860	$49,515	$45,895	$43,056	$92,786	$747,832
43	Change in FPPCA Revenue	(47,496)	(50,553)	(67,127)	(77,732)	(75,085)	(63,612)	(103,259)	(98,480)	(125,218)	(110,345)	(105,971)	(108,223)	(1,033,100)
44	Change in Total Revenue	$21,412	($6,513)	$12,581	$11,832	$11,322	($2,394)	($56,380)	($58,620)	($75,703)	($64,450)	($62,915)	($15,437)	($285,268)
45	Percentage Change in Base Rate Revenue	42.28%	22.64%	31.48%	33.79%	33.95%	26.12%	25.66%	25.38%	21.55%	22.20%	22.89%	52.03%	29.83%
46	Percentage Change in Total Revenue	10.17%	-2.66%	3.93%	3.45%	3.44%	-0.80%	-19.72%	-22.94%	-21.32%	-20.32%	-21.40%	-5.39%	-8.06%

Arizona Electric Power Cooperative, Inc.
DUNCAN ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
3	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
4	KWH - BASE RESOURCES	1,531,549	2,339,466	2,479,519	2,349,355	2,361,719	1,997,532	1,800,946	1,875,660	2,246,044	2,142,874	1,835,257	1,260,715	24,220,635
5	KWH - OTHER EXISTING RESOURCES	473,111	83,374	743,831	611,065	521,988	280,736	118,614	30,190	46,076	83,766	48,133	723,735	3,764,620
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	72,174	22,332	0	0	0	0	0	0	94,506
7														
8	**PRESENT RATES**													
9	Energy & FPPCA RATES													
10	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
11	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
12	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
13														
14	**PRESENT REVENUES**													
15	Demand Revenue	$57,823	$90,479	$104,261	$88,981	$99,168	$80,293	$60,220	$41,644	$64,414	$58,422	$58,422	$52,430	$856,556
16	Base Energy Charge Revenue	41,557	50,225	66,820	61,370	61,275	47,691	39,792	39,508	47,516	46,158	39,043	41,138	582,093
17	Total Present Base Rate Revenue	$99,379	$140,705	$171,081	$150,351	$160,443	$127,984	$100,012	$81,153	$111,930	$104,580	$97,465	$93,568	$1,438,650
18	FPPCA	25,499	30,819	47,577	43,696	43,629	33,957	51,329	50,962	61,291	59,540	50,362	53,064	551,725
19	Total Present Revenue	$124,879	$171,523	$218,657	$194,047	$204,072	$161,941	$151,341	$132,115	$173,221	$164,121	$147,827	$146,632	$1,990,375
20														
21	**PROPOSED RATES**													
22	Fixed Demand Charge	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	
23	O&M Demand Charge	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	
24	Base Resource Energy Charge	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	
25	Other Existing Resources Energy Charge	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	
26	Additional ARM Resources	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	
27	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
28														
29	**PROPOSED REVENUES**													
30	Fixed Demand Charge Revenue	$23,300	$36,459	$42,013	$35,856	$39,961	$32,355	$24,266	$16,781	$25,956	$23,542	$23,542	$21,127	$345,157
31	O&M Demand Charge Revenue	30,940	48,414	55,789	47,613	53,064	42,964	32,223	22,283	34,467	31,261	31,261	28,055	458,334
32	Base Resource Energy Revenue	49,557	75,698	80,230	76,018	76,418	64,634	58,273	60,691	72,676	69,337	59,384	40,793	783,710
33	Other Existing Resources Energy Revenu	31,841	5,611	50,061	41,125	35,130	18,894	7,983	2,032	3,101	5,638	3,239	48,708	253,363
34	Additional ARM Resources	0	0	0	0	5,298	1,639	0	0	0	0	0	0	6,938
35	Total Proposed Base Rate Revenue	$135,638	$166,184	$228,093	$200,613	$209,871	$160,486	$122,745	$101,787	$136,200	$129,778	$117,426	$138,683	$1,847,503
36	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total Proposed Revenue	$135,638	$166,184	$228,093	$200,613	$209,871	$160,486	$122,745	$101,787	$136,200	$129,778	$117,426	$138,683	$1,847,503
38														
39	**PROPOSED REVENUE CHANGES**													
40	Change in Fixed and Demand Revenue	($3,582)	($5,605)	($6,459)	($5,512)	($6,144)	($4,974)	($3,731)	($2,580)	($3,991)	($3,619)	($3,619)	($3,248)	($53,065)
41	Change in Base Energy Charge Revenue	39,841	31,084	63,471	55,774	55,572	37,476	26,464	23,215	28,261	28,817	23,580	48,364	451,918
42	Change in Base Rate Revenue	$36,259	$25,479	$57,012	$50,262	$49,428	$32,502	$22,733	$20,635	$24,270	$25,197	$19,961	$45,116	$408,853
43	Change in FPPCA Revenue	(25,499)	(30,819)	(47,577)	(43,696)	(43,629)	(33,957)	(51,329)	(50,962)	(61,291)	(59,540)	(50,362)	(53,064)	(551,725)
44	Change in Total Revenue	$10,759	($5,340)	$9,435	$6,566	$5,799	($1,455)	($28,596)	($30,328)	($37,021)	($34,343)	($30,401)	($7,949)	($142,872)
45	Percentage Change in Base Rate Revenu	36.49%	18.11%	33.32%	33.43%	30.81%	25.40%	22.73%	25.43%	21.68%	24.09%	20.48%	48.22%	28.42%
46	Percentage Change in Total Revenue	8.62%	-3.11%	4.31%	3.38%	2.84%	-0.90%	-18.89%	-22.96%	-21.37%	-20.93%	-20.57%	-5.42%	-7.18%

Arizona Electric Power Cooperative, Inc.
GRAHAM ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	20,966	31,511	39,951	39,726	36,986	32,263	24,968	18,448	20,642	19,992	16,818	20,271	324,562
3	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
4	KWH - BASE RESOURCES	8,232,123	11,822,788	14,230,236	14,265,620	14,106,426	11,983,452	10,392,305	10,170,848	11,758,796	10,715,505	8,985,666	7,418,708	134,082,474
5	KWH - OTHER EXISTING RESOURCES	2,542,989	421,342	4,268,930	3,710,478	3,117,807	1,684,170	684,458	163,708	241,224	418,873	235,665	4,258,835	21,748,479
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	431,089	133,972	0	0	0	0	0	0	565,062
7														
8	**PRESENT RATES**													
9	Energy & FPPCA RATES													
10	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
11	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
12	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
13														
14	**PRESENT REVENUES**													
15	Demand Revenue	$314,071	$472,035	$598,466	$595,095	$554,050	$483,300	$374,320	$276,351	$309,217	$299,480	$281,894	$303,660	$4,861,939
16	Base Energy Charge Revenue	223,368	253,821	383,488	372,645	365,995	286,107	229,621	214,235	248,760	230,816	191,158	242,075	3,242,089
17	Total Present Base Rate Revenue	$537,439	$725,856	$981,954	$967,740	$920,045	$769,407	$603,942	$490,586	$557,978	$530,296	$473,052	$545,735	$8,104,028
18	FPPCA	137,059	155,745	273,048	265,327	260,593	203,712	296,193	276,346	320,881	297,733	246,578	312,257	3,045,472
19	Total Present Revenue	$674,498	$881,601	$1,255,001	$1,233,067	$1,180,638	$973,118	$900,134	$766,932	$878,858	$828,029	$719,630	$857,993	$11,149,500
20														
21	**PROPOSED RATES**													
22	Fixed Demand Charge	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	
23	O&M Demand Charge	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	
24	Base Resource Energy Charge	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	
25	Other Existing Resources Energy Charge	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	
26	Additional ARM Resources	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	
27	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
28														
29	**PROPOSED REVENUES**													
30	Fixed Demand Charge Revenue	$126,556	$190,211	$241,158	$239,799	$223,260	$194,750	$150,836	$111,358	$124,602	$120,678	$113,592	$122,362	$1,959,164
31	O&M Demand Charge Revenue	168,056	252,581	320,233	318,429	296,466	258,609	200,295	147,873	165,459	160,249	150,838	162,485	2,601,572
32	Base Resource Energy Revenue	266,368	382,552	460,450	461,595	456,444	387,750	336,265	329,100	380,481	346,723	290,750	240,048	4,338,525
33	Other Existing Resources Energy Revenue	171,146	28,357	287,304	249,719	209,832	113,347	46,065	11,018	16,235	28,191	15,861	286,624	1,463,698
34	Additional ARM Resources	0	0	0	0	31,646	9,835	0	0	0	0	0	0	41,481
35	Total Proposed Base Rate Revenue	$732,128	$853,700	$1,309,144	$1,269,543	$1,217,648	$964,290	$733,461	$599,348	$686,776	$655,841	$571,041	$811,520	$10,404,440
36	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total Proposed Revenue	$732,128	$853,700	$1,309,144	$1,269,543	$1,217,648	$964,290	$733,461	$599,348	$686,776	$655,841	$571,041	$811,520	$10,404,440
38														
39	**PROPOSED REVENUE CHANGES**													
40	Change in Fixed and Demand Revenue	($19,457)	($29,243)	($37,076)	($36,867)	($34,324)	($29,941)	($23,190)	($17,120)	($19,156)	($18,553)	($17,464)	($18,812)	($301,203)
41	Change in Base Energy Charge Revenue	214,146	157,088	364,266	338,670	331,927	224,825	152,709	125,882	147,955	144,098	115,453	284,597	2,601,615
42	Change in Base Rate Revenue	$194,689	$127,845	$327,190	$301,803	$297,603	$194,884	$129,519	$108,762	$128,799	$125,545	$97,989	$265,785	$2,300,412
43	Change in FPPCA Revenue	(137,059)	(155,745)	(273,048)	(265,327)	(260,593)	(203,712)	(296,193)	(276,346)	(320,881)	(297,733)	(246,578)	(312,257)	(3,045,472)
44	Change in Total Revenue	$57,630	($27,901)	$54,143	$36,476	$37,010	($8,828)	($166,673)	($167,584)	($192,082)	($172,188)	($148,589)	($46,472)	($745,060)
45	Percentage Change in Base Rate Revenue	36.23%	17.61%	33.32%	31.19%	32.35%	25.33%	21.45%	22.17%	23.08%	23.67%	20.71%	48.70%	28.39%
46	Percentage Change in Total Revenue	8.54%	-3.16%	4.31%	2.96%	3.13%	-0.91%	-18.52%	-21.85%	-21.86%	-20.79%	-20.65%	-5.42%	-6.68%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.011050	$0.011050	$0.013050	$0.013050	$0.013050	$0.013050	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$855,113	$855,113	$855,113	$855,113	$855,113	$841,539	$855,113	$855,113	$855,113	$841,248	$855,113	$841,405	$10,220,208
7														
8	**PRESENT REVENUES**													
9	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
10	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
11	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
12	Demand Revenue	$1,814,798	$2,046,290	$2,167,510	$2,168,113	$2,167,010	$2,131,670	$1,926,246	$1,646,083	$1,719,895	$1,680,468	$1,698,967	$1,565,038	$22,732,087
13	Base Energy Charge Revenue	1,612,943	1,703,368	1,755,123	1,919,342	1,913,881	1,723,372	1,527,516	1,243,970	1,322,828	1,241,118	1,096,053	1,087,114	18,146,629
14	Total Present Base Rate Revenue	$3,427,741	$3,749,659	$3,922,633	$4,087,455	$4,080,891	$3,855,042	$3,453,762	$2,890,053	$3,042,723	$2,921,585	$2,795,020	$2,652,152	$40,878,716
15	FPPCA	859,770	907,970	1,104,889	1,208,269	1,204,831	1,084,901	1,879,736	1,530,809	1,627,850	1,527,299	1,348,785	1,337,785	15,622,895
16	Total Present Revenue	$4,287,511	$4,657,629	$5,027,522	$5,295,725	$5,285,722	$4,939,943	$5,333,498	$4,420,862	$4,670,573	$4,448,884	$4,143,805	$3,989,937	$56,501,611
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	
20	O&M Demand Charge	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	
21	Base Resource Energy Charge	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	
22	Other Existing Resources Energy Charge	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$9,268,508
27	O&M Demand Charge Revenue	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	16,923,155
28	Base Resource Energy Revenue	1,632,278	2,529,446	2,456,574	2,595,200	2,613,530	2,473,617	2,218,186	1,888,502	2,009,448	1,872,268	1,674,644	1,272,159	25,235,851
29	Other Existing Resources Energy Revenue	1,860,829	241,921	569,519	817,930	760,603	427,710	324,157	88,450	91,425	113,708	55,049	886,267	6,237,567
30	Total Proposed Base Rate Revenue	$5,675,745	$4,954,005	$5,208,732	$5,595,768	$5,556,772	$5,083,965	$4,724,981	$4,159,590	$4,283,512	$4,168,614	$3,912,332	$4,341,065	$57,665,081
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,675,745	$4,954,005	$5,208,732	$5,595,768	$5,556,772	$5,083,965	$4,724,981	$4,159,590	$4,283,512	$4,168,614	$3,912,332	$4,341,065	$57,665,081
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$367,841	$136,348	$15,128	$14,526	$15,629	$50,969	$256,392	$536,556	$462,743	$502,171	$483,672	$617,601	$3,459,575
36	Change in Energy Charge Revenue	1,880,163	1,067,998	1,270,970	1,493,787	1,460,252	1,177,955	1,014,827	732,982	778,045	744,858	633,640	1,071,312	13,326,790
37	Change in Base Rate Revenue	$2,248,004	$1,204,346	$1,286,098	$1,508,313	$1,475,881	$1,228,924	$1,271,219	$1,269,538	$1,240,789	$1,247,029	$1,117,312	$1,688,913	$16,786,365
38	Change in FPPCA Revenue	(859,770)	(907,970)	(1,104,889)	(1,208,269)	(1,204,831)	(1,084,901)	(1,879,736)	(1,530,809)	(1,627,850)	(1,527,299)	(1,348,785)	(1,337,785)	(15,622,895)
39	Change in Total Revenue	$1,388,234	$296,376	$181,209	$300,044	$271,049	$144,022	($608,517)	($261,272)	($387,061)	($280,270)	($231,473)	$351,127	$1,163,470
40	Percentage Change in Base Rate Revenue	65.58%	32.12%	32.79%	36.90%	36.17%	31.88%	36.81%	43.93%	40.78%	42.68%	39.98%	63.68%	41.06%
41	Percentage Change in Total Revenue	32.38%	6.36%	3.60%	5.67%	5.13%	2.92%	-11.41%	-5.91%	-8.29%	-6.30%	-5.59%	8.80%	2.06%

Arizona Electric Power Cooperative, Inc.
SULPHUR SPRINGS ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.011050	$0.011050	$0.013050	$0.013050	$0.013050	$0.013050	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$9,089,148
7														
8	**PRESENT REVENUES**													
9	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
10	KWH - BASE RESOURCES	45,109,060	71,215,769	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
11	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
12	Demand Revenue	$1,709,462	$1,758,830	$1,824,896	$1,771,898	$1,757,378	$1,744,310	$1,716,722	$1,616,534	$1,784,966	$1,778,911	$1,764,391	$1,693,243	$20,921,540
13	Base Energy Charge Revenue	1,446,096	1,558,774	1,553,892	1,562,858	1,569,492	1,501,590	1,434,581	1,287,408	1,460,597	1,440,640	1,326,890	1,416,282	17,559,098
14	Total Present Base Rate Revenue	$3,155,558	$3,317,604	$3,378,788	$3,334,756	$3,326,869	$3,245,900	$3,151,303	$2,903,941	$3,245,563	$3,219,551	$3,091,281	$3,109,525	$38,480,637
15	FPPCA	770,833	830,895	978,210	983,854	988,030	945,285	1,765,372	1,584,263	1,797,387	1,772,828	1,632,849	1,742,853	15,792,657
16	Total Present Revenue	$3,926,390	$4,148,499	$4,356,997	$4,318,610	$4,314,899	$4,191,184	$4,916,674	$4,488,204	$5,042,949	$4,992,378	$4,724,130	$4,852,378	$54,273,295
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	
20	O&M Demand Charge	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	
21	Base Resource Energy Charge	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	
22	Other Existing Resources Energy Charge	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$8,207,031
27	O&M Demand Charge Revenue	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	14,985,028
28	Base Resource Energy Revenue	1,456,919	2,300,106	2,188,667	2,243,945	2,266,907	2,209,164	2,057,216	1,890,587	2,093,958	2,031,535	1,868,960	1,236,876	23,844,840
29	Other Existing Resources Energy Revenu	1,645,489	265,575	480,184	394,804	368,707	269,395	367,667	238,139	375,504	440,258	409,980	2,004,284	7,259,986
30	Total Proposed Base Rate Revenue	$5,035,079	$4,498,353	$4,601,523	$4,571,421	$4,568,285	$4,411,231	$4,357,555	$4,061,397	$4,402,134	$4,404,465	$4,211,612	$5,173,831	$54,296,885
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,035,079	$4,498,353	$4,601,523	$4,571,421	$4,568,285	$4,411,231	$4,357,555	$4,061,397	$4,402,134	$4,404,465	$4,211,612	$5,173,831	$54,296,885
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$223,210	$173,842	$107,776	$160,774	$175,294	$188,362	$215,950	$316,138	$147,706	$153,761	$168,281	$239,429	$2,270,519
36	Change in Energy Charge Revenue	1,656,312	1,006,907	1,114,959	1,075,891	1,066,122	976,969	990,303	841,318	1,008,865	1,031,153	952,050	1,824,877	13,545,728
37	Change in Base Rate Revenue	$1,879,522	$1,180,749	$1,222,735	$1,236,665	$1,241,416	$1,165,331	$1,206,252	$1,157,456	$1,156,571	$1,184,914	$1,120,331	$2,064,306	$15,816,247
38	Change in FPPCA Revenue	(770,833)	(830,895)	(978,210)	(983,854)	(988,030)	(945,285)	(1,765,372)	(1,584,263)	(1,797,387)	(1,772,828)	(1,632,849)	(1,742,853)	(15,792,657)
39	Change in Total Revenue	$1,108,689	$349,854	$244,525	$252,811	$253,386	$220,047	($559,119)	($426,807)	($640,816)	($587,914)	($512,518)	$321,453	$23,590
40	Percentage Change in Base Rate Revenu	59.56%	35.59%	36.19%	37.08%	37.31%	35.90%	38.28%	39.86%	35.64%	36.80%	36.24%	66.39%	41.10%
41	Percentage Change in Total Revenue	28.24%	8.43%	5.61%	5.85%	5.87%	5.25%	-11.37%	-9.51%	-12.71%	-11.78%	-10.85%	6.62%	0.04%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
3	KWH - TOTAL	43,348,839	49,883,272	59,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
4	KWH - BASE RESOURCES	33,118,261	48,166,700	53,187,964	57,321,553	58,001,937	53,834,841	47,593,662	42,254,430	48,946,556	46,212,451	40,692,756	27,756,481	557,087,594
5	KWH - OTHER EXISTING RESOURCES	10,230,578	1,716,572	15,955,862	14,909,296	12,819,609	7,566,021	3,134,613	680,119	1,004,108	1,806,460	1,067,241	15,934,077	86,824,555
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	1,772,527	601,861	0	0	0	0	0	0	2,374,388
7														
8	**PRESENT RATES**													
9	Energy & FPPCA RATES													
10	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
11	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
12	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
13														
14	**PRESENT REVENUES**													
15	Demand Revenue	$1,286,872	$1,887,061	$2,465,588	$2,244,873	$2,331,577	$2,114,097	$1,745,844	$1,373,666	$1,354,447	$1,277,464	$1,217,095	$1,093,855	$20,392,439
16	Base Energy Charge Revenue	898,621	1,034,080	1,433,352	1,497,345	1,504,875	1,285,316	1,051,597	890,033	1,035,477	995,432	865,685	905,705	13,397,520
17	Total Present Base Rate Revenue	$2,185,493	$2,921,141	$3,898,940	$3,742,218	$3,836,452	$3,399,414	$2,797,441	$2,263,699	$2,389,924	$2,272,896	$2,082,780	$1,999,560	$33,789,959
18	FPPCA	551,397	634,515	1,020,563	1,066,127	1,071,489	915,160	1,356,474	1,148,070	1,335,681	1,284,026	1,116,662	1,168,286	12,668,450
19	Total Present Revenue	$2,736,891	$3,555,656	$4,919,503	$4,808,346	$4,907,941	$4,314,574	$4,153,915	$3,411,769	$3,725,605	$3,556,922	$3,199,442	$3,167,845	$46,458,408
20														
21	**PROPOSED RATES**													
22	Fixed Demand Charge	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	
23	O&M Demand Charge	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	
24	Base Resource Energy Charge	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	
25	Other Existing Resources Energy Charge	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	
26	Additional ARM Resources	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	
27	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
28														
29	**PROPOSED REVENUES**													
30	Fixed Demand Charge Revenue	$518,557	$760,409	$993,532	$904,593	$939,531	$851,896	$703,504	$553,532	$545,787	$514,766	$490,440	$440,779	$8,217,326
31	O&M Demand Charge Revenue	688,592	1,009,746	1,319,310	1,201,208	1,247,602	1,131,231	934,183	735,034	724,750	683,558	651,255	585,310	10,911,779
32	Base Resource Energy Revenue	1,071,612	1,558,537	1,721,010	1,854,761	1,876,777	1,741,941	1,539,995	1,367,233	1,583,771	1,495,303	1,316,701	898,120	18,025,761
33	Other Existing Resources Energy Revenue	688,530	115,527	1,073,848	1,003,413	862,774	509,202	210,963	45,773	67,578	121,577	71,827	1,072,382	5,843,393
34	Additional ARM Resources	0	0	0	0	130,120	44,182	0	0	0	0	0	0	174,302
35	Total Proposed Base Rate Revenue	$2,967,291	$3,444,219	$5,107,701	$4,963,975	$5,056,805	$4,278,452	$3,388,645	$2,701,571	$2,921,885	$2,815,204	$2,530,222	$2,996,591	$43,172,561
36	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total Proposed Revenue	$2,967,291	$3,444,219	$5,107,701	$4,963,975	$5,056,805	$4,278,452	$3,388,645	$2,701,571	$2,921,885	$2,815,204	$2,530,222	$2,996,591	$43,172,561
38														
39	**PROPOSED REVENUE CHANGES**													
40	Change in Fixed and Demand Revenue	($79,723)	($116,905)	($152,746)	($139,072)	($144,444)	($130,971)	($108,157)	($85,100)	($83,909)	($79,140)	($75,400)	($67,766)	($1,263,334)
41	Change in Base Energy Charge Revenue	661,520	639,984	1,361,507	1,360,829	1,364,796	1,010,009	699,361	522,972	815,871	621,448	522,843	1,064,797	10,645,936
42	Change in Base Rate Revenue	$781,797	$523,078	$1,208,761	$1,221,756	$1,220,352	$879,039	$591,204	$437,872	$531,961	$542,307	$447,443	$997,031	$9,382,602
43	Change in FPPCA Revenue	(551,397)	(634,515)	(1,020,563)	(1,066,127)	(1,071,489)	(915,160)	(1,356,474)	(1,148,070)	(1,335,681)	(1,284,026)	(1,116,662)	(1,168,286)	(12,668,450)
44	Change in Total Revenue	$230,400	($111,437)	$188,198	$155,629	$148,864	($36,122)	($765,270)	($710,198)	($803,719)	($741,718)	($669,220)	($171,254)	($3,285,848)
45	Percentage Change in Base Rate Revenue	35.77%	17.91%	31.00%	32.65%	31.81%	25.86%	21.13%	19.34%	22.26%	23.86%	21.48%	49.86%	27.77%
46	Percentage Change in Total Revenue	8.42%	-3.13%	3.83%	3.24%	3.03%	-0.84%	-18.42%	-20.82%	-21.57%	-20.85%	-20.92%	-5.41%	-7.07%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT REVENUES**													
2	FULL REQUIREMENTS													
3	Demand Revenue	$1,744,331	$2,561,745	$3,327,223	$3,084,801	$3,133,816	$2,822,756	$2,283,027	$1,772,374	$1,860,801	$1,756,600	$1,663,334	$1,544,378	$27,555,186
4	Base Energy Revenue	1,240,951	1,420,513	1,977,937	2,040,532	2,037,600	1,708,457	1,401,062	1,220,123	1,428,828	1,357,950	1,178,039	1,272,817	18,284,808
5	Total Present Base Rate Revenue	$2,985,282	$3,982,258	$5,305,159	$5,125,333	$5,171,416	$4,531,213	$3,684,089	$2,992,497	$3,289,628	$3,114,550	$2,841,373	$2,817,195	$45,839,993
6	FPPCA	761,452	871,632	1,408,314	1,452,882	1,450,794	1,216,441	1,807,255	1,573,859	1,843,071	1,751,644	1,519,574	1,641,830	17,298,747
7	Total Adjusted Present Revenue	$3,746,734	$4,853,890	$6,713,473	$6,578,215	$6,622,210	$5,747,654	$5,491,343	$4,566,355	$5,132,699	$4,866,194	$4,360,947	$4,459,025	$63,138,740
8														
9	PARTIAL REQUIREMENTS													
10	Fixed / O&M Charge Revenue	$3,524,260	$3,805,120	$3,992,406	$3,940,011	$3,924,387	$3,875,980	$3,642,968	$3,262,617	$3,504,861	$3,459,379	$3,463,358	$3,258,281	$43,653,627
11	Base Energy Revenue	3,059,039	3,262,142	3,309,014	3,482,200	3,483,373	3,224,962	2,962,096	2,531,378	2,783,425	2,681,757	2,422,943	2,503,396	35,705,726
12	Total Present Base Rate Revenue	$6,583,299	$7,067,263	$7,301,421	$7,422,211	$7,407,760	$7,100,942	$6,605,064	$5,793,994	$6,288,286	$6,141,136	$5,886,301	$5,761,677	$79,359,353
13	FPPCA	1,630,602	1,738,865	2,083,099	2,192,123	2,192,861	2,030,186	3,645,108	3,115,072	3,425,237	3,300,127	2,981,634	3,080,639	31,415,553
14	Total Adjusted Present Revenue	$8,213,901	$8,806,128	$9,384,520	$9,614,334	$9,600,622	$9,131,128	$10,250,172	$8,909,066	$9,713,522	$9,441,262	$8,867,935	$8,842,316	$110,774,906
15														
16	TOTAL CLASS A													
17	Demand Revenue	$5,268,591	$6,366,865	$7,319,629	$7,024,812	$7,058,203	$6,698,736	$5,925,995	$5,034,990	$5,365,662	$5,215,978	$5,126,692	$4,802,659	$71,208,813
18	Base Energy Revenue	4,299,990	4,682,656	5,286,951	5,522,732	5,520,973	4,933,419	4,363,158	3,751,501	4,212,252	4,039,707	3,600,982	3,776,213	53,990,534
19	Total Present Base Rate Revenue	$9,568,581	$11,049,521	$12,606,580	$12,547,544	$12,579,176	$11,632,155	$10,289,153	$8,786,491	$8,577,914	$9,255,686	$8,727,674	$8,578,872	$125,199,347
20	FPPCA	2,392,054	2,610,497	3,491,413	3,645,005	3,643,656	3,246,627	5,452,362	4,688,931	5,268,308	5,051,771	4,501,208	4,722,468	48,714,300
21	Total Adjusted Present Revenue	$11,960,635	$13,660,018	$16,097,993	$16,192,550	$16,222,832	$14,878,782	$15,741,515	$13,475,422	$14,846,222	$14,307,457	$13,228,882	$13,301,341	$173,913,646
22														
23	**PROPOSED REVENUES**													
24	FULL REQUIREMENTS													
25	Demand Revenue	$1,636,268	$2,403,042	$3,121,098	$2,893,695	$2,939,673	$2,647,883	$2,141,591	$1,662,573	$1,745,522	$1,647,776	$1,560,289	$1,448,702	$25,848,111
26	Base Energy Revenue	2,430,667	2,299,657	3,856,732	3,895,023	3,885,532	3,050,972	2,332,832	1,937,052	2,278,652	2,205,718	1,889,533	2,769,211	32,831,581
27	Total Proposed Base Rate Revenue	$4,066,935	$4,702,699	$6,977,829	$6,788,717	$6,825,205	$5,698,856	$4,474,423	$3,599,625	$4,024,174	$3,853,494	$3,449,822	$4,217,913	$58,679,693
28	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Adjusted Proposed Revenue	$4,066,935	$4,702,699	$6,977,829	$6,788,717	$6,825,205	$5,698,856	$4,474,423	$3,599,625	$4,024,174	$3,853,494	$3,449,822	$4,217,913	$58,679,693
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$49,383,722
33	Base Energy Revenue	6,595,514	5,337,047	5,694,944	6,051,879	6,009,747	5,379,886	4,967,226	4,105,677	4,570,335	4,457,769	4,008,633	5,399,586	62,578,244
34	Total Proposed Base Rate Revenue	$10,710,824	$9,452,357	$9,810,254	$10,167,189	$10,125,057	$9,495,196	$9,082,536	$8,220,988	$8,685,646	$8,573,079	$8,123,944	$9,514,896	$111,961,966
35	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Adjusted Proposed Revenue	$10,710,824	$9,452,357	$9,810,254	$10,167,189	$10,125,057	$9,495,196	$9,082,536	$8,220,988	$8,685,646	$8,573,079	$8,123,944	$9,514,896	$111,961,966
37														
38	TOTAL CLASS A													
39	Demand Revenue	$5,751,578	$6,518,352	$7,236,408	$7,009,005	$7,054,983	$6,763,194	$6,256,901	$5,777,883	$5,860,832	$5,763,087	$5,675,599	$5,564,012	$75,231,833
40	Base Energy Revenue	9,026,182	7,636,705	9,551,676	9,946,902	9,895,279	8,430,858	7,300,058	6,042,729	6,848,987	6,663,486	5,898,166	8,168,798	95,409,826
41	Total Proposed Base Rate Revenue	$14,777,760	$14,155,057	$16,788,084	$16,955,906	$16,950,262	$15,194,052	$13,556,959	$11,820,612	$12,709,819	$12,426,573	$11,573,765	$13,732,809	$170,641,659
42	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Adjusted Proposed Revenue	$14,777,760	$14,155,057	$16,788,084	$16,955,906	$16,950,262	$15,194,052	$13,556,959	$11,820,612	$12,709,819	$12,426,573	$11,573,765	$13,732,809	$170,641,659
44														
45	**PROPOSED REVENUE CHANGES**													
46	FULL REQUIREMENTS													
47	Demand Revenue	($108,063)	($158,703)	($206,125)	($191,107)	($194,143)	($174,873)	($141,436)	($109,801)	($115,279)	($108,823)	($103,045)	($95,676)	($1,707,074)
48	Base Energy Revenue	1,189,716	879,144	1,878,795	1,854,491	1,847,933	1,342,515	931,771	716,929	849,824	847,767	711,494	1,498,394	14,546,774
49	Change in Base Rate Revenue	$1,081,653	$720,441	$1,672,670	$1,663,384	$1,653,789	$1,167,643	$790,335	$607,128	$734,545	$738,944	$608,448	$1,400,718	$12,839,699
50	FPPCA	(761,452)	(871,632)	(1,408,314)	(1,452,882)	(1,450,794)	(1,216,441)	(1,807,255)	(1,573,859)	(1,843,071)	(1,751,644)	(1,519,574)	(1,641,830)	(17,298,747)
51	Total Revenue Change	$320,201	($151,191)	$264,356	$210,502	$202,995	($48,799)	($1,016,920)	($966,731)	($1,108,525)	($1,012,700)	($911,125)	($241,112)	($4,459,048)
52	Percent Change in Base Rate Revenue	16.43%	10.19%	22.91%	22.41%	22.33%	16.44%	11.97%	10.48%	11.68%	12.03%	10.34%	24.31%	18.18%
53	Percent Change in Total Revenue	8.55%	-3.11%	3.94%	3.20%	3.07%	-0.85%	-18.52%	-21.17%	-21.60%	-20.81%	-20.89%	-5.41%	-7.06%
54														
55	PARTIAL REQUIREMENTS													
56	Fixed / O&M Charge Revenue	$591,050	$310,190	$122,904	$175,299	$180,923	$239,330	$472,342	$852,694	$610,449	$655,931	$651,952	$857,029	$5,730,095
57	Base Energy Revenue	3,536,475	2,074,905	2,385,930	2,569,679	2,526,374	2,154,924	2,005,130	1,574,300	1,786,911	1,776,012	1,585,690	2,896,189	26,872,518
58	Change in Base Rate Revenue	$4,127,526	$2,385,095	$2,508,834	$2,744,978	$2,717,298	$2,394,255	$2,477,472	$2,426,993	$2,397,360	$2,431,943	$2,237,643	$3,753,219	$32,602,613
59	FPPCA	(1,630,602)	(1,738,865)	(2,083,099)	(2,192,123)	(2,192,861)	(2,030,186)	(3,645,108)	(3,115,072)	(3,425,237)	(3,300,127)	(2,981,634)	(3,080,639)	(31,415,553)
60	Total Revenue Change	$2,496,924	$646,230	$425,735	$552,855	$524,435	$364,069	($1,167,636)	($688,079)	($1,027,877)	($868,183)	($743,992)	$672,580	$1,187,060
61	Percent Change in Base Rate Revenue	62.70%	33.75%	34.36%	36.98%	36.68%	33.72%	37.51%	41.89%	38.12%	39.60%	38.01%	65.14%	41.08%
62	Percent Change in Total Revenue	30.40%	7.34%	4.54%	5.75%	5.46%	3.99%	-11.39%	-7.72%	-10.58%	-9.20%	-8.39%	7.61%	1.07%
63														
64	TOTAL CLASS A													
65	Demand Revenue	$482,987	$151,487	($83,221)	($15,808)	($3,221)	$64,458	$330,906	$742,893	$495,170	$547,108	$548,907	$761,353	$4,023,020
66	Base Energy Revenue	4,726,192	2,954,049	4,264,725	4,424,170	4,374,307	3,497,440	2,936,900	2,291,228	2,636,735	2,623,779	2,297,184	4,392,583	41,419,292
67	Percent Change in Base Rate Revenue	$5,209,179	$3,105,536	$4,181,504	$4,408,362	$4,371,086	$3,561,897	$3,267,806	$3,034,121	$3,131,905	$3,170,887	$2,846,091	$5,153,936	$45,442,312
68	FPPCA	(2,392,054)	(2,610,497)	(3,491,413)	(3,645,005)	(3,643,656)	(3,246,627)	(5,452,362)	(4,688,931)	(5,268,308)	(5,051,771)	(4,501,208)	(4,722,468)	(48,714,300)
69	Total Revenue Change	$2,817,125	$495,039	$690,091	$763,357	$727,430	$315,270	($2,184,556)	($1,654,809)	($2,136,402)	($1,880,884)	($1,655,117)	$431,468	($3,271,988)
70	Percent Change in Base Rate Revenue	54.44%	28.11%	33.17%	35.13%	34.75%	30.62%	31.76%	34.53%	32.70%	34.26%	32.61%	60.08%	36.30%
71	Percent Change in Total Revenue	23.55%	3.62%	4.29%	4.71%	4.48%	2.12%	-13.88%	-12.28%	-14.39%	-13.15%	-12.51%	3.24%	-1.88%

Arizona Electric Power Cooperative, Inc.

ANALYSIS OF REVENUE BY DETAILED CLASS WITH ACTUAL FPPCA

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**AVERAGE COST PER KWH - PRESENT REVENUES**													
2	ANZA	$0.05637	$0.06167	$0.07043	$0.06508	$0.06478	$0.06915	$0.07405	$0.06939	$0.07581	$0.07685	$0.07420	$0.07080	$0.06904
3	DUNCAN	$0.06229	$0.07079	$0.06784	$0.06555	$0.06904	$0.07039	$0.07884	$0.06932	$0.07557	$0.07371	$0.07849	$0.07389	$0.07088
4	GRAHAM	$0.06260	$0.07200	$0.06784	$0.06859	$0.06687	$0.07051	$0.08126	$0.07421	$0.07324	$0.07437	$0.07804	$0.07347	$0.07129
5	MOHAVE	$0.05510	$0.05668	$0.05938	$0.05720	$0.05725	$0.05942	$0.07238	$0.07367	$0.07319	$0.07431	$0.07837	$0.07608	$0.06455
6	SULPHER	$0.05629	$0.05517	$0.05813	$0.05728	$0.05699	$0.05786	$0.07105	$0.07227	$0.07157	$0.07184	$0.07381	$0.07102	$0.06407
7	TRICO	$0.06314	$0.07128	$0.07115	$0.06657	$0.06761	$0.06959	$0.08189	$0.07946	$0.07459	$0.07407	$0.07661	$0.07251	$0.07189
8	AEPCO CLASS A	$0.05766	$0.06047	$0.06312	$0.06078	$0.06091	$0.06252	$0.07479	$0.07446	$0.07306	$0.07342	$0.07616	$0.07302	$0.06678
9														
10	**AVERAGE COST PER KWH - PROPOSED REVENUES**													
11	ANZA	$0.06210	$0.06004	$0.07320	$0.06733	$0.06701	$0.06859	$0.05945	$0.05347	$0.05965	$0.06123	$0.05832	$0.06699	$0.06347
12	DUNCAN	$0.06766	$0.06859	$0.07076	$0.06776	$0.07100	$0.06976	$0.06394	$0.05341	$0.05942	$0.05828	$0.06235	$0.06988	$0.06579
13	GRAHAM	$0.06795	$0.06972	$0.07077	$0.07062	$0.06897	$0.06987	$0.06622	$0.05799	$0.05723	$0.05890	$0.06193	$0.06949	$0.06653
14	MOHAVE	$0.07295	$0.06029	$0.06152	$0.06044	$0.06019	$0.06115	$0.06412	$0.06932	$0.06713	$0.06963	$0.07400	$0.08278	$0.06587
15	SULPHER	$0.07218	$0.05982	$0.06139	$0.06064	$0.06034	$0.06090	$0.06297	$0.06540	$0.06248	$0.06338	$0.06580	$0.07573	$0.06410
16	TRICO	$0.06845	$0.06905	$0.07387	$0.06872	$0.06966	$0.06900	$0.06680	$0.06292	$0.05850	$0.05863	$0.06059	$0.06859	$0.06680
17	AEPCO CLASS A	$0.07124	$0.06266	$0.06583	$0.06365	$0.06364	$0.06384	$0.06441	$0.06532	$0.06255	$0.06377	$0.06663	$0.07539	$0.06552

Arizona Electric Power Cooperative, Inc.
ANZA ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
3	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
4	KWH - BASE RESOURCES	2,852,721	3,837,518	3,498,387	4,179,337	4,064,489	3,742,041	3,622,972	3,624,544	4,588,670	3,971,349	3,861,740	2,571,184	44,414,952
5	KWH - OTHER EXISTING RESOURCES	881,235	136,762	1,049,481	1,087,043	898,335	525,912	238,616	58,340	94,134	155,241	101,281	1,476,031	6,702,411
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	124,210	41,835	0	0	0	0	0	0	166,045
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	Energy & FPPCA RATES													
10	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
11	FPPCA - SYNCHRONIZATION	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
12	Demand Charge - Full	*$14.98*	*$14.98*	*$14.98*	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
13														
14	**PRESENT REVENUES**													
15	Demand Revenue	$85,566	$112,170	$158,908	$155,852	$149,021	$145,066	$102,643	$80,712	$132,723	$121,233	$105,924	$94,434	$1,444,252
16	Base Energy Charge Revenue	77,405	82,387	94,277	109,172	105,454	89,342	80,051	76,346	97,075	85,544	82,153	83,899	1,063,105
17	Total Present Base Rate Revenue	$162,971	$194,557	$253,185	$265,024	$254,475	$234,408	$182,694	$157,058	$229,797	$206,777	$188,077	$178,333	$2,507,357
18	FPPCA	61,581	65,544	75,004	86,854	83,896	71,077	63,686	60,738	77,229	68,056	65,358	66,747	845,770
19	Total Present Revenue	$224,551	$260,101	$328,189	$351,878	$338,371	$305,486	$246,379	$217,797	$307,027	$274,833	$253,435	$245,080	$3,353,127
20														
21	**PROPOSED RATES**													
22	Fixed Demand Charge	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	
23	O&M Demand Charge	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	
24	Base Resource Energy Charge	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	
25	Other Existing Resources Energy Charge	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	
26	Additional ARM Resources	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	
27	PPFAC	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
28														
29	**PROPOSED REVENUES**													
30	Fixed Demand Charge Revenue	$34,480	$45,200	$64,033	$62,802	$60,049	$58,456	$41,361	$32,524	$53,482	$48,852	$42,683	$38,053	$581,975
31	O&M Demand Charge Revenue	45,785	60,021	85,030	83,395	79,740	77,623	54,923	43,188	71,019	64,871	56,679	50,531	772,804
32	Base Resource Energy Revenue	92,306	124,171	113,198	135,231	131,515	121,082	117,229	117,280	148,476	128,501	124,955	83,196	1,437,141
33	Other Existing Resources Energy Revenue	59,308	9,204	70,631	73,159	60,459	35,394	16,059	3,926	6,335	10,448	6,816	99,339	451,080
34	Additional ARM Resources	0	0	0	0	9,118	3,071	0	0	0	0	0	0	12,189
35	Total Proposed Base Rate Revenue	$231,879	$238,597	$332,892	$354,587	$340,881	$295,627	$229,572	$196,918	$279,312	$252,672	$231,133	$271,118	$3,255,189
36	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total Proposed Revenue	$231,879	$238,597	$332,892	$354,587	$340,881	$295,627	$229,572	$196,918	$279,312	$252,672	$231,133	$271,118	$3,255,189
38														
39	**PROPOSED REVENUE CHANGES**													
40	Change in Fixed and Demand Revenue	($5,301)	($6,949)	($9,845)	($9,655)	($9,232)	($8,987)	($6,359)	($5,000)	($8,222)	($7,511)	($6,562)	($5,850)	($89,473)
41	Change in Base Energy Charge Revenue	74,209	50,989	89,552	99,219	95,638	70,205	53,237	44,860	57,737	53,405	49,618	98,636	837,305
42	Change in Base Rate Revenue	$68,908	$44,039	$79,707	$89,563	$86,406	$61,218	$46,879	$39,860	$49,515	$45,895	$43,056	$92,786	$747,832
43	Change in FPPCA Revenue	(61,581)	(65,544)	(75,004)	(86,854)	(83,896)	(71,077)	(63,686)	(60,738)	(77,229)	(68,056)	(65,358)	(66,747)	(845,770)
44	Change in Total Revenue	$7,328	($21,505)	$4,703	$2,710	$2,510	($9,859)	($16,807)	($20,879)	($27,715)	($22,161)	($22,303)	$26,039	($97,938)
45	Percentage Change in Base Rate Revenue	42.28%	22.64%	31.48%	33.79%	33.95%	26.12%	25.66%	25.38%	21.55%	22.20%	22.89%	52.03%	29.83%
46	Percentage Change in Total Revenue	3.26%	-8.27%	1.43%	0.77%	0.74%	-3.23%	-6.82%	-9.59%	-9.03%	-8.06%	-8.80%	10.62%	-2.92%

Arizona Electric Power Cooperative, Inc.

DUNCAN ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
	BILLING DETERMINANTS													
1	KW	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
2	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
3	KWH - BASE RESOURCES	1,531,549	2,339,466	2,479,519	2,349,355	2,361,719	1,997,532	1,800,946	1,875,660	2,246,044	2,142,874	1,835,257	1,260,715	24,220,635
4	KWH - OTHER EXISTING RESOURCES	473,111	83,374	743,831	611,065	521,988	280,736	118,614	30,190	46,076	83,766	48,133	723,735	3,764,620
5	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	72,174	22,332	0	0	0	0	0	0	94,506
6														
7	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
8	Energy & FPPCA RATES													
9	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
10	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
11	*Demand Charge - Full*	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
12														
13	**PRESENT REVENUES**													
14	Demand Revenue	$57,823	$90,479	$104,261	$88,981	$99,168	$80,293	$60,220	$41,644	$64,414	$58,422	$58,422	$52,430	$856,556
15	Base Energy Charge Revenue	41,557	50,225	66,820	61,370	61,275	47,691	39,792	39,508	47,516	46,158	39,043	41,138	582,093
16	Total Present Base Rate Revenue	$99,379	$140,705	$171,081	$150,351	$160,443	$127,984	$100,012	$81,153	$111,930	$104,580	$97,465	$93,568	$1,438,650
17	FPPCA	33,061	39,958	53,160	48,824	48,749	37,942	31,658	31,431	37,802	36,722	31,061	32,728	463,094
18	Total Present Revenue	$132,440	$180,662	$224,241	$199,174	$209,192	$165,926	$131,670	$112,584	$149,731	$141,302	$128,526	$126,295	$1,901,744
19														
20	**PROPOSED RATES**													
21	Fixed Demand Charge	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	
22	O&M Demand Charge	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	
23	Base Resource Energy Charge	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	
24	Other Existing Resources Energy Charge	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	
25	Additional ARM Resources	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	
26	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
27														
28	**PROPOSED REVENUES**													
29	Fixed Demand Charge Revenue	$23,300	$36,459	$42,013	$35,856	$39,961	$32,355	$24,266	$16,781	$25,956	$23,542	$23,542	$21,127	$345,157
30	O&M Demand Charge Revenue	30,940	48,414	55,789	47,613	53,064	42,964	32,223	22,283	34,467	31,261	31,261	28,055	458,334
31	Base Resource Energy Revenue	49,557	75,698	80,230	76,018	76,418	64,634	58,273	60,691	72,676	69,337	59,384	40,793	783,710
32	*Other Existing Resources Energy Revenu*	31,841	5,611	50,061	41,125	35,130	18,894	7,983	2,032	3,101	5,638	3,239	48,708	253,363
33	Additional ARM Resources	0	0	0	0	5,298	1,639	0	0	0	0	0	0	6,938
34	Total Proposed Base Rate Revenue	$135,638	$166,184	$228,093	$200,613	$209,871	$160,486	$122,745	$101,787	$136,200	$129,778	$117,426	$138,683	$1,847,503
35	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Proposed Revenue	$135,638	$166,184	$228,093	$200,613	$209,871	$160,486	$122,745	$101,787	$136,200	$129,778	$117,426	$138,683	$1,847,503
37														
38	**PROPOSED REVENUE CHANGES**													
39	Change in Fixed and Demand Revenue	($3,582)	($5,605)	($6,459)	($5,512)	($6,144)	($4,974)	($3,731)	($2,580)	($3,991)	($3,619)	($3,619)	($3,246)	($53,065)
40	Change in Base Energy Charge Revenue	39,841	31,084	63,471	55,774	55,572	37,476	26,464	23,215	28,261	28,817	23,580	48,364	461,918
41	Change in Base Rate Revenue	$36,259	$25,479	$57,012	$50,262	$49,428	$32,502	$22,733	$20,635	$24,270	$25,197	$19,961	$45,116	$408,853
42	Change in FPPCA Revenue	(33,061)	(39,958)	(53,160)	(48,824)	(48,749)	(37,942)	(31,658)	(31,431)	(37,802)	(36,722)	(31,061)	(32,728)	(463,094)
43	Change in Total Revenue	$3,198	($14,479)	$3,852	$1,438	$680	($5,440)	($8,924)	($10,797)	($13,531)	($11,525)	($11,100)	$12,388	($54,241)
44	Percentage Change in Base Rate Revenu	36.49%	18.11%	33.32%	33.43%	30.81%	25.40%	22.73%	25.43%	21.68%	24.09%	20.48%	48.22%	28.42%
45	Percentage Change in Total Revenue	2.41%	-8.01%	1.72%	0.72%	0.32%	-3.28%	-6.78%	-9.59%	-9.04%	-8.16%	-8.64%	9.81%	-2.85%

Arizona Electric Power Cooperative, Inc.

GRAHAM ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
3	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
4	KWH - BASE RESOURCES	8,232,123	11,822,788	14,230,236	14,265,620	14,106,426	11,983,452	10,392,305	10,170,848	11,758,796	10,715,505	8,985,666	7,418,708	134,082,474
5	KWH - OTHER EXISTING RESOURCES	2,542,989	421,342	4,268,930	3,710,478	3,117,807	1,684,170	684,458	163,708	241,224	418,873	235,665	4,258,835	21,748,479
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	431,089	133,972	0	0	0	0	0	0	565,062
7														
8	**PRESENT RATES**													
9	Energy & FPPCA RATES													
10	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
11	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
12	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
13														
14	**PRESENT REVENUES**													
15	Demand Revenue	$314,071	$472,035	$598,466	$595,095	$554,050	$483,300	$374,320	$276,351	$309,217	$299,480	$281,894	$303,660	$4,861,939
16	Base Energy Charge Revenue	223,368	253,821	383,488	372,645	365,995	286,107	229,621	214,235	248,760	230,816	191,158	242,075	3,242,089
17	Total Present Base Rate Revenue	$537,439	$725,856	$981,954	$967,740	$920,045	$769,407	$603,942	$490,586	$557,978	$530,296	$473,052	$545,735	$8,104,028
18	FPPCA	177,704	201,931	305,090	296,463	291,173	227,617	182,679	170,436	197,905	183,629	152,079	192,587	2,579,296
19	Total Present Revenue	$715,143	$927,787	$1,287,044	$1,264,203	$1,211,218	$997,024	$786,620	$661,025	$755,883	$713,925	$625,131	$738,322	$10,683,325
20														
21	**PROPOSED RATES**													
22	Fixed Demand Charge	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	
23	O&M Demand Charge	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	
24	Base Resource Energy Charge	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	
25	Other Existing Resources Energy Charge	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	
26	Additional ARM Resources	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	
27	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
28														
29	**PROPOSED REVENUES**													
30	Fixed Demand Charge Revenue	$126,558	$190,211	$241,158	$239,799	$223,260	$194,750	$150,836	$111,358	$124,602	$120,678	$113,592	$122,362	$1,959,164
31	O&M Demand Charge Revenue	168,056	252,581	320,233	318,429	296,466	258,609	200,295	147,873	165,459	160,249	150,838	162,485	2,601,572
32	Base Resource Energy Revenue	266,368	382,552	460,450	461,595	456,444	387,750	336,265	329,100	380,481	346,723	290,750	240,048	4,338,525
33	Other Existing Resources Energy Revenue	171,146	28,357	287,304	249,719	209,832	113,347	46,065	11,018	16,235	28,191	15,861	286,624	1,463,698
34	Additional ARM Resources	0	0	0	0	31,646	9,835	0	0	0	0	0	0	41,481
35	Total Proposed Base Rate Revenue	$732,128	$853,700	$1,309,144	$1,269,543	$1,217,648	$964,290	$733,461	$599,348	$686,776	$655,841	$571,041	$811,520	$10,404,440
36	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total Proposed Revenue	$732,128	$853,700	$1,309,144	$1,269,543	$1,217,648	$964,290	$733,461	$599,348	$686,776	$655,841	$571,041	$811,520	$10,404,440
38														
39	**PROPOSED REVENUE CHANGES**													
40	Change in Fixed and Demand Revenue	($19,457)	($29,243)	($37,076)	($36,867)	($34,324)	($29,941)	($23,190)	($17,120)	($19,156)	($18,553)	($17,464)	($18,812)	($301,203)
41	Change in Base Energy Charge Revenue	214,146	157,088	364,266	338,670	331,927	224,825	152,709	125,882	147,955	144,098	115,453	284,597	2,601,615
42	Change in Base Rate Revenue	$194,689	$127,845	$327,190	$301,803	$297,603	$194,884	$129,519	$108,762	$128,799	$125,545	$97,989	$265,785	$2,300,412
43	Change in FPPCA Revenue	(177,704)	(201,931)	(305,090)	(296,463)	(291,173)	(227,617)	(182,679)	(170,436)	(197,905)	(183,629)	(152,079)	(192,587)	(2,579,296)
44	Change in Total Revenue	$16,985	($74,087)	$22,100	$5,339	$6,430	($32,733)	($53,160)	($61,677)	($69,106)	($58,084)	($54,090)	$73,198	($278,884)
45	Percentage Change in Base Rate Revenue	36.23%	17.61%	33.32%	31.19%	32.35%	25.33%	21.45%	22.17%	23.08%	23.67%	20.71%	48.70%	28.39%
46	*Percentage Change in Total Revenue*	2.38%	-7.99%	1.72%	0.42%	0.53%	-3.28%	-6.76%	-9.33%	-9.14%	-8.14%	-8.65%	9.91%	-2.61%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$855,113	$855,113	$855,113	$855,113	$855,113	$841,539	$855,113	$855,113	$855,113	$841,248	$855,113	$841,405	$10,220,208
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
10	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
11	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
12	Demand Revenue	$1,814,798	$2,046,290	$2,167,510	$2,168,113	$2,167,010	$2,131,670	$1,926,246	$1,646,083	$1,719,895	$1,680,468	$1,698,967	$1,565,038	$22,732,087
13	Base Energy Charge Revenue	1,612,943	1,703,368	1,755,123	1,919,342	1,913,881	1,723,372	1,527,516	1,243,970	1,322,828	1,241,118	1,096,053	1,087,114	18,146,629
14	Total Present Base Rate Revenue	$3,427,741	$3,749,659	$3,922,633	$4,087,455	$4,080,891	$3,855,042	$3,453,762	$2,890,053	$3,042,723	$2,921,585	$2,795,020	$2,652,152	$40,878,716
15	FPPCA	1,184,537	1,250,945	1,288,953	1,409,555	1,405,545	1,265,635	1,121,800	913,565	971,478	911,470	804,936	798,371	13,326,790
16	Total Present Revenue	$4,612,278	$5,000,603	$5,211,586	$5,497,011	$5,486,436	$5,120,677	$4,575,562	$3,803,618	$4,014,201	$3,833,055	$3,599,956	$3,450,523	$54,205,506
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	
20	O&M Demand Charge	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	$1,410,263	
21	Base Resource Energy Charge	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	$0.03216	
22	Other Existing Resources Energy Charge	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$772,376	$9,268,508
27	O&M Demand Charge Revenue	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	1,410,263	16,923,155
28	Base Resource Energy Revenue	1,632,278	2,529,446	2,456,574	2,595,200	2,613,530	2,473,617	2,218,186	1,888,502	2,009,448	1,872,268	1,674,644	1,272,159	25,235,851
29	Other Existing Resources Energy Revenue	1,860,829	241,921	569,519	817,930	760,603	427,710	324,157	88,450	91,425	113,708	55,049	886,267	6,237,567
30	Total Proposed Base Rate Revenue	$5,675,745	$4,954,005	$5,208,732	$5,595,768	$5,556,772	$5,083,965	$4,724,981	$4,159,590	$4,283,512	$4,168,614	$3,912,332	$4,341,065	$57,665,081
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,675,745	$4,954,005	$5,208,732	$5,595,768	$5,556,772	$5,083,965	$4,724,981	$4,159,590	$4,283,512	$4,168,614	$3,912,332	$4,341,065	$57,665,081
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$367,841	$136,348	$15,128	$14,526	$15,629	$50,969	$256,392	$536,556	$462,743	$502,171	$483,672	$617,601	$3,459,575
36	Change in Energy Charge Revenue	1,880,163	1,067,998	1,270,970	1,493,787	1,460,252	1,177,955	1,014,827	732,982	778,045	744,858	633,640	1,071,312	13,326,790
37	Change in Base Rate Revenue	$2,248,004	$1,204,346	$1,286,098	$1,508,313	$1,475,881	$1,228,924	$1,271,219	$1,269,538	$1,240,789	$1,247,029	$1,117,312	$1,688,913	$16,786,365
38	Change in FPPCA Revenue	(1,184,537)	(1,250,945)	(1,288,953)	(1,409,555)	(1,405,545)	(1,265,635)	(1,121,800)	(913,565)	(971,478)	(911,470)	(804,936)	(798,371)	(13,326,790)
39	Change in Total Revenue	$1,063,467	($46,599)	($2,854)	$98,758	$70,336	($36,712)	$149,420	$355,972	$269,311	$335,559	$312,376	$890,541	$3,459,575
40	Percentage Change in Base Rate Revenue	65.58%	32.12%	32.79%	36.90%	36.17%	31.88%	36.81%	43.93%	40.78%	42.68%	39.98%	63.68%	41.06%
41	Percentage Change in Total Revenue	23.06%	-0.93%	-0.05%	1.80%	1.28%	-0.72%	3.27%	9.36%	6.71%	8.75%	8.66%	25.81%	6.38%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$9,089,148
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
10	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
11	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
12	Demand Revenue	$1,709,462	$1,758,830	$1,824,896	$1,771,898	$1,757,378	$1,744,310	$1,716,722	$1,616,534	$1,784,966	$1,778,911	$1,764,391	$1,693,243	$20,921,540
13	Base Energy Charge Revenue	1,446,096	1,558,774	1,553,892	1,562,858	1,569,492	1,501,590	1,434,581	1,287,408	1,460,597	1,440,640	1,326,890	1,416,282	17,559,098
14	Total Present Base Rate Revenue	$3,155,558	$3,317,604	$3,378,788	$3,334,756	$3,326,869	$3,245,900	$3,151,303	$2,903,941	$3,245,563	$3,219,551	$3,091,281	$3,109,525	$38,480,637
15	FPPCA	1,115,571	1,202,495	1,198,729	1,205,646	1,210,763	1,158,381	1,106,688	993,153	1,126,758	1,111,362	1,023,611	1,092,571	13,545,728
16	Total Present Revenue	$4,271,129	$4,520,099	$4,577,516	$4,540,401	$4,537,632	$4,404,281	$4,257,990	$3,897,095	$4,372,320	$4,330,913	$4,114,892	$4,202,096	$52,026,365
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	
20	O&M Demand Charge	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	$1,248,752	
21	Base Resource Energy Charge	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	$0.03230	
22	Other Existing Resources Energy Charge	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$683,919	$8,207,031
27	O&M Demand Charge Revenue	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	1,248,752	14,985,028
28	Base Resource Energy Revenue	1,456,919	2,300,106	2,188,667	2,243,945	2,266,907	2,209,164	2,057,216	1,890,587	2,093,958	2,031,535	1,868,960	1,236,876	23,844,840
29	Other Existing Resources Energy Revenue	1,645,489	265,575	480,184	394,804	368,707	269,395	367,667	238,139	375,504	440,258	409,980	2,004,284	7,259,986
30	Total Proposed Base Rate Revenue	$5,035,079	$4,498,353	$4,601,523	$4,571,421	$4,568,285	$4,411,231	$4,357,555	$4,061,397	$4,402,134	$4,404,465	$4,211,612	$5,173,831	$54,296,885
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,035,079	$4,498,353	$4,601,523	$4,571,421	$4,568,285	$4,411,231	$4,357,555	$4,061,397	$4,402,134	$4,404,465	$4,211,612	$5,173,831	$54,296,885
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$223,210	$173,842	$107,776	$160,774	$175,294	$188,362	$215,950	$316,138	$147,706	$153,761	$168,281	$239,429	$2,270,519
36	Change in Energy Charge Revenue	1,656,312	1,006,907	1,114,959	1,075,891	1,066,122	976,969	990,303	841,318	1,008,865	1,031,153	952,050	1,824,877	13,545,728
37	Change in Base Rate Revenue	$1,879,522	$1,180,749	$1,222,735	$1,236,665	$1,241,416	$1,165,331	$1,206,252	$1,157,456	$1,156,571	$1,184,914	$1,120,331	$2,064,306	$15,816,247
38	Change in FPPCA Revenue	(1,115,571)	(1,202,495)	(1,198,729)	(1,205,646)	(1,210,763)	(1,158,381)	(1,106,688)	(993,153)	(1,126,758)	(1,111,362)	(1,023,611)	(1,092,571)	(13,545,728)
39	Change in Total Revenue	$763,951	($21,746)	$24,006	$31,019	$30,653	$6,950	$99,564	$164,303	$29,813	$73,552	$96,720	$971,734	$2,270,519
40	Percentage Change in Base Rate Revenue	59.56%	35.59%	36.19%	37.08%	37.31%	35.90%	38.28%	39.86%	35.64%	36.80%	36.24%	66.39%	41.10%
41	Percentage Change in Total Revenue	17.89%	-0.48%	0.52%	0.68%	0.68%	0.16%	2.34%	4.22%	0.68%	1.70%	2.35%	23.12%	4.36%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,276	81,248	73,021	1,361,311
3	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
4	KWH - BASE RESOURCES	33,118,261	48,166,700	53,187,964	57,321,553	58,001,937	53,834,841	47,593,662	42,254,430	48,946,556	46,212,451	40,692,756	27,756,481	557,087,594
5	KWH - OTHER EXISTING RESOURCES	10,230,578	1,716,572	15,955,862	14,909,296	12,819,609	7,566,021	3,134,613	680,119	1,004,108	1,806,460	1,067,241	15,934,077	85,824,555
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	1,772,527	601,861	0	0	0	0	0	0	2,374,388
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	Energy & FPPCA RATES													
10	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
11	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
12	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.99	$14.98	$14.98	$14.98	$14.98	
13														
14	**PRESENT REVENUES**													
15	Demand Revenue	$1,286,872	$1,887,061	$2,465,588	$2,244,873	$2,331,577	$2,114,097	$1,745,844	$1,373,666	$1,354,447	$1,277,464	$1,217,095	$1,093,855	$20,392,439
16	Base Energy Charge Revenue	898,621	1,034,080	1,433,352	1,497,345	1,504,875	1,285,316	1,051,597	890,033	1,035,477	995,432	865,685	905,705	13,397,520
17	Total Present Base Rate Revenue	$2,185,493	$2,921,141	$3,898,940	$3,742,218	$3,836,452	$3,399,414	$2,797,441	$2,263,699	$2,389,924	$2,272,896	$2,082,780	$1,999,560	$33,789,959
18	FPPCA	714,913	822,679	1,140,326	1,191,237	1,197,228	1,022,554	836,615	708,080	823,791	791,932	688,709	720,548	10,658,613
19	Total Present Revenue	$2,900,406	$3,743,820	$5,039,266	$4,933,456	$5,033,680	$4,421,968	$3,634,056	$2,971,779	$3,213,715	$3,064,828	$2,771,489	$2,720,108	$44,448,572
20														
21	**PROPOSED RATES**													
22	Fixed Demand Charge	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	$6.036	
23	O&M Demand Charge	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	$8.016	
24	Base Resource Energy Charge	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	$0.03236	
25	Other Existing Resources Energy Charge	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	$0.06730	
26	Additional ARM Resources	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	$0.07341	
27	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
28														
29	**PROPOSED REVENUES**													
30	Fixed Demand Charge Revenue	$518,557	$760,409	$993,532	$904,593	$939,531	$851,896	$703,504	$553,532	$545,787	$514,766	$490,440	$440,779	$8,217,326
31	O&M Demand Charge Revenue	688,592	1,009,746	1,319,310	1,201,208	1,247,602	1,131,231	934,183	735,034	724,750	683,558	651,255	585,310	10,911,779
32	Base Resource Energy Revenue	1,071,612	1,558,537	1,721,010	1,854,761	1,876,777	1,741,941	1,539,995	1,367,233	1,583,771	1,495,303	1,316,701	898,120	18,025,761
33	Other Existing Resources Energy Revenue	688,530	115,527	1,073,848	1,003,413	862,774	509,202	210,963	45,773	67,578	121,577	71,827	1,072,382	5,843,393
34	Additional ARM Resources	0	0	0	0	130,120	44,182	0	0	0	0	0	0	174,302
35	Total Proposed Base Rate Revenue	$2,967,291	$3,444,219	$5,107,701	$4,963,975	$5,056,805	$4,278,452	$3,388,645	$2,701,571	$2,921,885	$2,815,204	$2,530,222	$2,996,591	$43,172,561
36	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total Proposed Revenue	$2,967,291	$3,444,219	$5,107,701	$4,963,975	$5,056,805	$4,278,452	$3,388,645	$2,701,571	$2,921,885	$2,815,204	$2,530,222	$2,996,591	$43,172,561
38														
39	**PROPOSED REVENUE CHANGES**													
40	Change in Fixed and Demand Revenue	($79,723)	($116,905)	($152,746)	($139,072)	($144,444)	($130,971)	($108,157)	($85,100)	($83,909)	($79,140)	($75,400)	($67,766)	($1,263,334)
41	Change in Base Energy Charge Revenue	861,520	639,984	1,361,507	1,360,829	1,364,796	1,010,009	699,361	522,972	615,871	621,448	522,843	1,064,797	10,645,936
42	Change in Base Rate Revenue	$781,797	$523,078	$1,208,761	$1,221,756	$1,220,352	$879,039	$591,204	$437,872	$531,961	$542,307	$447,443	$997,031	$9,382,602
43	Change in FPPCA Revenue	(714,913)	(822,679)	(1,140,326)	(1,191,237)	(1,197,228)	(1,022,554)	(836,615)	(708,080)	(823,791)	(791,932)	(688,709)	(720,548)	(10,658,613)
44	Change in Total Revenue	$66,885	($299,601)	$68,435	$30,519	$23,125	($143,516)	($245,411)	($270,208)	($291,829)	($249,625)	($241,267)	$276,483	($1,276,011)
45	Percentage Change in Base Rate Revenue	35.77%	17.91%	31.00%	32.65%	31.81%	25.86%	21.13%	19.34%	22.26%	23.86%	21.48%	49.86%	27.77%
46	Percentage Change in Total Revenue	2.31%	-8.00%	1.36%	0.62%	0.46%	-3.25%	-6.75%	-9.09%	-9.08%	-8.14%	-8.71%	10.16%	-2.87%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH SYNCHRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT REVENUES w/ FPPAC SYNCHRONIZED**													
2	FULL REQUIREMENTS													
3	Demand Revenue	$1,744,331	$2,561,745	$3,327,223	$3,084,801	$3,133,816	$2,822,756	$2,283,027	$1,772,374	$1,860,801	$1,756,800	$1,663,334	$1,544,378	$27,555,186
4	Base Energy Revenue	1,240,951	1,420,513	1,977,937	2,040,532	2,037,600	1,708,457	1,401,062	1,220,123	1,428,828	1,357,950	1,178,039	1,272,817	18,284,808
5	Total Present Base Rate Revenue	$2,985,282	$3,982,258	$5,305,159	$5,125,333	$5,171,416	$4,531,213	$3,684,089	$2,992,497	$3,289,628	$3,114,550	$2,841,373	$2,817,195	$45,839,993
6	FPPCA	987,259	1,130,112	1,573,579	1,623,378	1,621,045	1,359,190	1,114,637	970,689	1,138,727	1,080,339	937,208	1,012,610	14,546,774
7	Total Adjusted Present Revenue	$3,972,541	$5,112,370	$6,878,739	$6,748,711	$6,792,461	$5,890,404	$4,798,726	$3,963,185	$4,428,356	$4,194,889	$3,778,581	$3,829,805	$60,386,767
8														
9	PARTIAL REQUIREMENTS													
10	Fixed / O&M Charge Revenue	$3,524,260	$3,805,120	$3,992,408	$3,940,011	$3,924,387	$3,875,980	$3,642,968	$3,262,617	$3,504,861	$3,459,379	$3,463,358	$3,258,281	$43,653,627
11	Base Energy Revenue	3,059,039	3,262,142	3,309,014	3,482,200	3,483,373	3,224,962	2,962,096	2,531,378	2,783,425	2,681,757	2,422,943	2,503,396	35,705,726
12	Total Present Base Rate Revenue	$6,583,299	$7,067,263	$7,301,421	$7,422,211	$7,407,760	$7,100,942	$6,605,064	$5,793,994	$6,288,286	$6,141,136	$5,886,301	$5,761,677	$79,359,353
13	FPPCA	2,300,108	2,453,440	2,487,682	2,615,201	2,616,308	2,424,017	2,228,487	1,906,718	2,098,235	2,022,832	1,828,547	1,890,943	26,872,518
14	Total Adjusted Present Revenue	$8,883,407	$9,520,703	$9,789,102	$10,037,412	$10,024,068	$9,524,958	$8,833,552	$7,700,712	$8,386,521	$8,163,968	$7,714,848	$7,652,620	$106,231,871
15														
16	TOTAL CLASS A													
17	Demand Revenue	$5,268,591	$6,366,865	$7,319,629	$7,024,812	$7,058,203	$6,698,736	$5,925,995	$5,034,990	$5,365,662	$5,215,978	$5,126,692	$4,802,659	$71,208,813
18	Base Energy Revenue	4,299,990	4,682,656	5,286,951	5,522,732	5,520,973	4,933,419	4,363,158	3,751,501	4,212,252	4,039,707	3,600,982	3,776,213	53,990,534
19	Total Present Base Rate Revenue	$9,568,581	$11,049,521	$12,606,580	$12,547,544	$12,579,176	$11,632,155	$10,289,153	$8,786,491	$9,577,914	$9,255,686	$8,727,674	$8,578,872	$125,199,347
20	FPPCA	3,287,367	3,583,552	4,061,261	4,238,578	4,237,353	3,783,207	3,343,125	2,877,407	3,234,962	3,103,171	2,765,755	2,903,553	41,419,292
21	Total Adjusted Present Revenue	$12,855,948	$14,633,073	$16,667,841	$16,786,123	$16,816,529	$15,415,362	$13,632,278	$11,663,898	$12,812,877	$12,358,857	$11,493,429	$11,482,425	$166,618,638
22														
23	**PROPOSED REVENUES**													
24	FULL REQUIREMENTS													
25	Demand Revenue	$1,636,288	$2,403,042	$3,121,098	$2,893,695	$2,939,673	$2,647,883	$2,141,591	$1,662,573	$1,745,522	$1,647,776	$1,560,289	$1,448,702	$25,848,111
26	Base Energy Revenue	2,430,667	2,299,657	3,856,732	3,895,023	3,885,532	3,050,972	2,332,832	1,937,052	2,278,652	2,205,718	1,889,533	2,769,211	32,831,581
27	Total Proposed Base Rate Revenue	$4,066,935	$4,702,699	$6,977,829	$6,788,717	$6,825,205	$5,698,856	$4,474,423	$3,599,625	$4,024,174	$3,853,494	$3,449,822	$4,217,913	$58,679,693
28	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Adjusted Proposed Revenue	$4,066,935	$4,702,699	$6,977,828	$6,788,717	$6,825,205	$5,698,856	$4,474,423	$3,599,625	$4,024,174	$3,853,494	$3,449,822	$4,217,913	$58,679,693
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$4,115,310	$49,383,722
33	Base Energy Revenue	6,595,514	5,337,047	5,694,944	6,051,879	6,009,747	5,379,886	4,967,226	4,105,677	4,570,335	4,457,769	4,008,633	5,399,586	62,578,244
34	Total Proposed Base Rate Revenue	$10,710,824	$9,452,357	$9,810,254	$10,167,189	$10,125,057	$9,495,196	$9,082,536	$8,220,988	$8,685,646	$8,573,079	$8,123,944	$9,514,896	$111,961,966
35	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Adjusted Proposed Revenue	$10,710,824	$9,452,357	$9,810,254	$10,167,189	$10,125,057	$9,495,196	$9,082,536	$8,220,988	$8,685,646	$8,573,079	$8,123,944	$9,514,896	$111,961,966
37														
38	TOTAL CLASS A													
39	Demand Revenue	$5,751,578	$6,518,352	$7,236,408	$7,009,005	$7,054,983	$6,763,194	$6,256,901	$5,777,883	$5,860,832	$5,763,087	$5,675,599	$5,564,012	$75,231,833
40	Base Energy Revenue	9,026,182	7,636,705	9,551,676	9,946,902	9,895,279	8,430,858	7,300,058	6,042,729	6,848,987	6,663,486	5,898,166	8,168,796	85,409,826
41	Total Proposed Base Rate Revenue	$14,777,760	$14,155,057	$16,788,084	$16,955,906	$16,950,262	$15,194,052	$13,556,959	$11,820,612	$12,709,819	$12,426,573	$11,573,765	$13,732,809	$170,641,659
42	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Adjusted Proposed Revenue	$14,777,760	$14,155,057	$16,788,084	$16,955,906	$16,950,262	$15,194,052	$13,556,959	$11,820,612	$12,709,819	$12,426,573	$11,573,765	$13,732,809	$170,641,659
44														
45	**PROPOSED REVENUE CHANGES**													
46	FULL REQUIREMENTS													
47	Demand Revenue	($108,063)	($158,703)	($206,125)	($191,107)	($194,143)	($174,873)	($141,436)	($109,801)	($115,279)	($108,823)	($103,045)	($95,676)	($1,707,074)
48	Base Energy Revenue	1,189,716	879,144	1,878,795	1,854,491	1,847,933	1,342,515	931,771	716,929	849,824	847,767	711,494	1,496,394	14,546,774
49	Change in Base Rate Revenue	$1,081,653	$720,441	$1,672,670	$1,663,384	$1,653,789	$1,167,643	$790,335	$607,128	$734,545	$738,944	$608,449	$1,400,718	$12,838,699
50	FPPCA	(987,259)	(1,130,112)	(1,573,579)	(1,623,378)	(1,621,045)	(1,359,190)	(1,114,637)	(970,689)	(1,136,727)	(1,080,339)	(937,208)	(1,012,610)	(14,546,774)
51	Total Revenue Change	$94,395	($409,671)	$99,091	$40,007	$32,744	($191,548)	($324,302)	($363,560)	($402,182)	($341,395)	($328,759)	$388,108	($1,707,074)
52	Percent Change in Base Rate Revenue	16.43%	10.19%	22.91%	22.41%	22.33%	16.44%	11.97%	10.48%	11.68%	12.03%	10.34%	24.31%	16.18%
53	Percent Change in Total Revenue	2.38%	-8.01%	1.44%	0.59%	0.48%	-3.25%	-6.76%	-9.17%	-9.09%	-8.14%	-8.70%	10.13%	-2.83%
54														
55	PARTIAL REQUIREMENTS													
56	Fixed / O&M Charge Revenue	$591,050	$310,190	$122,904	$175,299	$190,923	$239,330	$472,342	$852,694	$610,449	$855,931	$651,952	$857,029	$5,730,095
57	Base Energy Revenue	3,536,475	2,074,905	2,385,930	2,569,679	2,526,374	2,154,924	2,005,130	1,574,300	1,786,911	1,776,012	1,585,690	2,896,189	26,872,518
58	Change in Base Rate Revenue	$4,127,525	$2,385,095	$2,508,834	$2,744,978	$2,717,296	$2,394,255	$2,477,472	$2,426,993	$2,397,360	$2,431,943	$2,237,643	$3,753,219	$32,602,613
59	FPPCA	(2,300,108)	(2,453,440)	(2,487,682)	(2,615,201)	(2,616,308)	(2,424,017)	(2,228,487)	(1,906,718)	(2,098,235)	(2,022,832)	(1,828,547)	(1,890,843)	(26,872,518)
60	Total Revenue Change	$1,827,417	($68,345)	$21,152	$129,777	$100,989	($29,762)	$248,984	$520,275	$299,125	$409,111	$409,096	$1,862,276	$5,730,095
61	Percent Change in Base Rate Revenue	62.70%	33.75%	34.36%	36.98%	36.68%	33.72%	37.51%	41.89%	38.12%	39.60%	38.01%	65.14%	41.08%
62	Percent Change in Total Revenue	20.57%	-0.72%	0.22%	1.29%	1.01%	-0.31%	2.82%	6.76%	3.57%	5.01%	5.30%	24.34%	5.39%
63														
64	TOTAL CLASS A													
65	Demand Revenue	$482,987	$151,487	($83,221)	($15,808)	($3,221)	$64,458	$330,906	$742,893	$495,170	$547,108	$548,907	$761,353	$4,023,020
66	Base Energy Revenue	4,726,192	2,954,049	4,264,725	4,424,170	4,374,307	3,497,440	2,936,900	2,291,228	2,636,735	2,623,779	2,297,184	4,392,583	41,419,292
67	Percent Change in Base Rate Revenue	$5,209,179	$3,105,536	$4,181,504	$4,408,362	$4,371,086	$3,561,897	$3,267,808	$3,034,121	$3,131,905	$3,170,887	$2,846,091	$5,153,936	$45,442,312
68	FPPCA	(3,287,367)	(3,583,552)	(4,061,261)	(4,238,578)	(4,237,353)	(3,783,207)	(3,343,125)	(2,877,407)	(3,234,962)	(3,103,171)	(2,765,755)	(2,903,553)	(41,419,292)
69	Total Revenue Change	$1,921,812	($478,016)	$120,243	$169,784	$133,733	($221,310)	($75,318)	$156,715	($103,057)	$67,716	$80,336	$2,250,383	$4,023,020
70	Percent Change in Base Rate Revenue	54.44%	28.11%	33.17%	35.13%	34.75%	30.62%	31.76%	34.53%	32.70%	34.26%	32.61%	60.08%	36.30%
71	Percent Change in Total Revenue	14.95%	-3.27%	0.72%	1.01%	0.80%	-1.44%	-0.55%	1.34%	-0.80%	0.55%	0.70%	19.60%	2.41%

Arizona Electric Power Cooperative, Inc.
ANALYSIS OF REVENUE BY DETAILED CLASS WITH SYNCHRONIZED FPPCA

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**AVERAGE COST PER KWH - PRESENT REVENUES**													
2	ANZA	$0.06014	$0.06545	$0.07216	$0.06682	$0.06652	$0.07088	$0.06380	$0.05914	$0.06556	$0.06660	$0.06395	$0.06056	$0.06538
3	DUNCAN	$0.06607	$0.07457	$0.06957	$0.06728	$0.07077	$0.07212	$0.06859	$0.05907	$0.06532	$0.06346	$0.06824	$0.06364	$0.06773
4	GRAHAM	$0.06637	$0.07577	$0.06957	$0.07033	$0.06860	$0.07224	$0.07102	$0.06396	$0.06299	$0.06412	$0.06779	$0.06323	$0.06831
5	MOHAVE	$0.05928	$0.06086	$0.06155	$0.05937	$0.05943	$0.06160	$0.06210	$0.06338	$0.06291	$0.06402	$0.06609	$0.06580	$0.06192
6	SULPHER	$0.06123	$0.06011	$0.06107	$0.06022	$0.05993	$0.06080	$0.06153	$0.06275	$0.06206	$0.06232	$0.06429	$0.06151	$0.06142
7	TRICO	$0.06691	$0.07505	$0.07288	$0.06830	$0.06934	$0.07132	$0.07164	$0.06922	$0.06434	$0.06383	$0.06637	$0.06226	$0.06878
8	AEPCO CLASS A	$0.06198	$0.06478	$0.06535	$0.06301	$0.06314	$0.06477	$0.06477	$0.06445	$0.06306	$0.06342	$0.06616	$0.06303	$0.06397
9														
10	**AVERAGE COST PER KWH - PROPOSED REVENUES**													
11	ANZA	$0.06210	$0.06004	$0.07320	$0.06733	$0.06701	$0.06859	$0.05945	$0.05347	$0.05965	$0.06123	$0.05832	$0.06699	$0.06347
12	DUNCAN	$0.06766	$0.06859	$0.07076	$0.06776	$0.07100	$0.06976	$0.06394	$0.05341	$0.05942	$0.05828	$0.06235	$0.06988	$0.06579
13	GRAHAM	$0.06795	$0.06972	$0.07077	$0.07062	$0.06897	$0.06987	$0.06622	$0.05799	$0.05723	$0.05890	$0.06193	$0.06949	$0.06653
14	MOHAVE	$0.07295	$0.06029	$0.06152	$0.06044	$0.06019	$0.06115	$0.06412	$0.06932	$0.06713	$0.06963	$0.07400	$0.08278	$0.06587
15	SULPHER	$0.07218	$0.05982	$0.06139	$0.06064	$0.06034	$0.06090	$0.06297	$0.06540	$0.06248	$0.06338	$0.06580	$0.07573	$0.06410
16	TRICO	$0.06845	$0.06905	$0.07387	$0.06872	$0.06966	$0.06900	$0.06680	$0.06292	$0.05850	$0.05863	$0.06059	$0.06859	$0.06680
17	AEPCO CLASS A	$0.07124	$0.06266	$0.06583	$0.06365	$0.06364	$0.06384	$0.06441	$0.06532	$0.06255	$0.06377	$0.06663	$0.07539	$0.06552

Arizona Electric Power Cooperative, Inc.
CHANGES IN REPRESENTATIVE RATE SCHEDULES

Line No.	RATE DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS
1	PRESENT MONTHLY CHARGES			
2	FIXED CHARGE	$855,113	$757,429	$14.980
3	O&M CHARGE	$7.260	$7.260	N/A
4	TOTAL FIXED CHARGE PLUS O&M CHARGE	$1,894,341	$1,743,462	$14.980
5	BASE ENERGY CHARGE	N/A	N/A	N/A
6	OTHER EXISTING RESOURCE ENERGY CHARGE	N/A	N/A	N/A
7	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	N/A
8	AVERAGE ENERGY CHARGE	$0.020730	$0.020730	$0.020730
9				
10	PROPOSED MONTHLY CHARGES			
11	FIXED CHARGE	$772,376	$683,919	$6.036
12	O&M CHARGE	$1,410,263	$1,248,752	$8.016
13	TOTAL FIXED CHARGE PLUS O&M CHARGE	$2,182,639	$1,932,672	$14.052
14	BASE ENERGY CHARGE	$0.032160	$0.032298	$0.032357
15	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.068787	$0.066755	$0.067301
16	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	$0.073409
17	AVERAGE ENERGY CHARGE	$0.035954	$0.036722	$0.037222
18				
19	CHANGE IN MONTHLY CHARGES			
20	FIXED CHARGE	($82,737)	($73,510)	($8.944)
21	O&M CHARGE	$371,035	$262,720	$8.016
22	TOTAL FIXED CHARGE PLUS O&M CHARGE	$288,298	$189,210	($0.928)
23	BASE ENERGY CHARGE	N/A	N/A	N/A
24	OTHER EXISTING RESOURCE ENERGY CHARGE	N/A	N/A	N/A
25	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	N/A
26	AVERAGE ENERGY CHARGE	$0.015224	$0.015992	$0.016492

Arizona Electric Power Cooperative, Inc.

TYPICAL BILL ANALYSIS

THIS SCHEDULE IS NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

BILL COUNT

THIS SCHEDULE IS NOT APPLICABLE