NEW APPLICATION

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AZ CORP COMMISSION
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Arizona Corporation Commission
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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

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-12-_____

APPLICATION E-01773A-12-0305

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 three all-requirements ("ARM" or "CARM") and three 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 13-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 Schedules in support of AEPCO's rate application. Also submitted

are the Direct Testimonies of Messrs. Scott and Pierson in support of this Application. In summary, the Schedules and Testimony support AEPCO's request for an overall 2.92% decrease in revenue requirements. That average decrease is a blend of a 1.30% decrease from the ARMs and a 3.12% decrease in revenues from the PRMs collectively. The requested rates are designed to produce a Debt Service Coverage Ratio of 1.32 and operating margins of approximately $931,000.

4. AEPCO's current rates were authorized by the Commission in Decision No. 72055, as amended in certain respects by Decision No. 72735. AEPCO's proposed rates are based on the same cost causation principles approved in those prior Decisions.

5. AEPCO requests that the Commission authorize the following rates for the CARMs: a fixed charge of $280,598 per month; a fixed O&M charge of $458,175 per month; and two energy rates: a Base Resources energy rate of $0.02921/kWh and an Other Existing Resources energy rate of $0.04795/kWh. Both the fixed charge and the O&M charge are apportioned between the CARMs on the basis of each CARM's load ratio share of its 12-month average demand compared to the total CARMs' 12-month average demand.

6. The requested revised rates for Mohave Electric Cooperative, Inc. ("MEC") are: a fixed charge of $856,355 per month; a fixed O&M charge of $1,419,059 per month; and two energy rates: a Base Resources energy rate of $0.02894/kWh and an Other Existing Resources energy rate of $0.05437/kWh. Requested revised rates for Sulphur Springs Valley Electric Cooperative ("SSVEC") are: a fixed charge of $758,281 per month; a fixed O&M charge of $1,256,541 per month; and two energy rates: a Base Resources energy rate of $0.02938/kWh and an Other Existing Resources energy rate of $0.05109/kWh. Finally, the requested revised rates for TRICO Electric Cooperative ("TRICO") are: a fixed charge of $743,828 per month; a

fixed O&M charge of $859,840 per month; and two energy rates: a Base Resources energy rate of $0.02947/kWh and an Other Existing Resources energy rate of $0.04219/kWh.

7. AEPCO also requests that the Commission approve revised depreciation rates for its production units as discussed in Mr. Scott's testimony.

8. Finally, AEPCO requests that the Commission approve continuance of the Purchased Power and Fuel Adjustor Clause ("PPFAC") with the modifications described in Mr. Pierson's testimony.

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. Approving revised depreciation rates; and

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

RESPECTFULLY SUBMITTED this 5th day of July, 2012.

GALLAGHER & KENNEDY, P.A.

By Michael M. Grant

Michael M. Grant
Jennifer A. Cranston
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 5th day of July, 2012, with:

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

Copies of this Application and Direct Testimony hand delivered this 5th day of July, 2012, to:

Janice Alward, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of this Application, Schedules and Direct Testimony delivered this 5th day of July, 2012, to:

Terri Ford
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10421-67/3076011

Arizona Electric Power Cooperative, Inc.
AEPCO
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.

APPLICATION

for

GENERAL RATE RELIEF

DOCKET NO. E-01773A

JULY 2012

A Touchstone Energy® Cooperative

Arizona Electric Power Cooperative, Inc.

R14-2-103.B Schedules
in Support of:

Application
for
General Rate Relief

Test Year Ending December 31, 2011

Arizona Electric Power Cooperative, Inc.
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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

Computation of Increase in Gross Revenue Requirements
Test Year End 12/31/2011

6/26/2012

LINE NO.			ORIGINAL COST	
1.	ADJUSTED RATE BASE	$	267,463,587 (a)	
2.	ADJUSTED ELECTRIC OPERATING INCOME (MARGINS)		15,204,121 (b)	
3.	CURRENT RATE OF RETURN		5.68%	
4.	REQUIRED ELECTRIC OPERATING INCOME (MARGINS)		10,676,656 (c)	
5.	REQUIRED RATE OF RETURN		3.99%	
6.	OPERATING INCOME DEFICIENCY	$	(4,527,465)	
7.	INCREASE (decrease) IN GROSS REV. REQUIREMENTS	$	(4,527,465)	
	CUSTOMER CLASSIFICATION		PROJECTED REVENUE INC. DUE TO RATES	% DOLLAR INCREASE
			(d)	(d)
8.	MEMBER CONTRACTS (ALL AND PARTIAL REQUIREMENTS)	$	(4,527,465)	-2.92%
9.	OTHER FIRM CONTRACTS (PARTIAL REQ.)		-	-
10.	TOTAL	$	(4,527,465)	-2.92%

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

Arizona Electric Power Cooperative, Inc.

Summary Results of Operations

LINE NO.		-PRIOR YEARS- 12/31/2009 (a)	12/31/2010 (a)	12/31/2011 TEST YEAR ACTUAL (a)	TEST YEAR ADJUSTED (b)	PROPOSED RATES (c)
1.	GROSS REVENUE	$ 209,152,219	$ 207,377,079	$ 169,668,330	$ 163,624,600	$ 159,097,135
2.	OPERATING EXPENSES	186,926,335	187,384,479	157,703,741	148,420,479	148,420,479
3.	ELECTRIC OPERATING INCOME (MARGINS)	22,225,884	19,992,600	11,964,589	15,204,121	10,676,656
4.	TOTAL INTEREST & OTHER DEDUCTIONS	13,857,781	11,593,844	11,135,447	9,745,481	9,745,481
5.	TOTAL OTHER NON OPERATING INCOME	1,588,822	1,104,800	1,026,046	1,026,046	1,026,046
5a.	EXTRAORDINARY ITEMS	-	-	-	-	-
6.	NET INCOME (MARGINS)	$ 9,956,925	$ 9,503,556	$ 1,855,188	$ 6,484,686	$ 1,957,221
7.	THROUGH 14.	NOT APPLICABLE				
15.	TIMES TOTAL INTEREST EARNED (TIER)	1.94	1.88	1.18	1.70	1.21
16.	DEBT SERVICE COVERAGE (DSC)	1.70	1.65	1.19	1.56	1.32

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

LINE NO.	DESCRIPTION	PRIOR YEARS 12/31/2009	PRIOR YEARS 12/31/2010	ACTUAL TEST YEAR 12/31/2011 (c)	END OF PROJECTED YR 12/31/2012 (c)
1.	SHORT-TERM DEBT	$ 22,442,010	$ 9,747,026	$ 3,721,518	$ 3,721,518
2.	LONG-TERM DEBT	180,177,566	196,895,823	216,731,512	200,063,388
3.	TOTAL DEBT (a)	202,619,576	206,642,849	220,453,030	203,784,906
4.	PREFERRED STOCK	-	-	-	-
5.	MARGINS AND EQUITY (b)	84,514,994	94,018,553	95,873,741	97,830,962
6.	TOTAL CAPITAL	$ 287,134,570	$ 300,661,402	$ 316,326,771	$ 301,615,868
	CAPITALIZATION RATIOS: (%)				
7.	SHORT-TERM DEBT	7.82%	3.24%	1.18%	1.23%
8.	LONG-TERM DEBT	62.75%	65.49%	68.52%	66.33%
9.	TOTAL DEBT	70.57%	68.73%	69.69%	67.56%
10.	PREFERRED STOCK	0.00%	0.00%	0.00%	0.00%
11.	MARGINS AND EQUITY	29.43%	31.27%	30.31%	32.44%
		100.00%	100.00%	100.00%	100.00%
12.	WEIGHTED COST OF SHORT TERM DEBT	0.27%	0.02%	0.01%	0.01%
13.	WEIGHTED COST OF LONG TERM DEBT	4.70%	5.11%	4.78%	4.53%
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
6/26/2012

LINE NO.			CONSTRUCTION EXPENDITURES			NET PLANT ADDITIONS			GROSS UTILITY PLANT IN SERVICE	
1.	12/31/2009	$	16,664,155	(a)	$	24,866,946		$	426,909,628	(d)
2.	12/31/2010		18,536,384	(a)		(11,635,908)			438,545,536	(c)
3.	12/31/2011		16,872,378	(a)		14,158,596	(c)		452,704,132	(c)
4.	12/31/2012		14,936,433	(b)		4,164,264			456,868,396	
5.	12/31/2013		6,128,422	(b)		14,936,433			471,804,829	
6.	12/31/2014		7,617,623	(b)		6,128,422			477,933,251	

SUPPORTING SCHEDULES:
(a) E-3, LINE 13
(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

SCHEDULE A-5
6/26/2012

LINE NO.		-PRIOR YEARS (a)- 12/31/2009	12/31/2010	12 MOS. ENDED 12/31/2011 ACTUAL TEST YEAR	PRESENT RATES (b)	PROPOSED RATES (b)
1.	NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 9,227,797	$ 31,821,264	$ (13,940,473)	$ (9,994,975)	$ (14,522,440)
2.	NET CASH USED IN INVESTING ACTIVITIES	(14,408,349)	(19,988,322)	(19,295,572)	(19,295,572)	(19,295,572)
3.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	5,126,003	(1,077,880)	23,366,654	23,366,654	23,366,654
4.	NET DECREASE IN CASH AND CASH EQ.	$ (54,549)	$ 10,755,062	$ (9,869,391)	$ (5,923,893)	$ (10,451,358)

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

B

Arizona Electric Power Cooperative, Inc.

Summary of Original Cost Rate Base

SCHEDULE B-1
6/26/2012

LINE NO.		ORIGINAL COST RATE BASE*	
1.	GROSS UTILITY PLANT IN SERVICE	$ 452,690,894	(a)
2.	LESS: ACCUMULATED DEPRECIATION & AMORT.	(219,978,356)	(a)
3.	NET UTILITY PLANT IN SERVICE	$ 232,712,538	(a)
	LESS:		
4.	CUSTOMER ADVANCES FOR CONSTRUCTION	-	
5.	CONTRIBUTION IN AID OF CONSTRUCTION	-	
6.	ADD: ALLOWANCE FOR WORKING CAPITAL	34,751,049	(b)
7.	PLANT HELD FOR FUTURE USE	-	(c)
8.	DEFERRED DEBITS	-	(d)
9.	TOTAL RATE BASE	$ 267,463,587	(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.

SCHEDULE B-2

Original Cost Rate Base Pro Forma Adjustments

6/26/2012

LINE NO.		ACTUAL TEST YEAR 12/31/2011 (a)	PRO FORMA ADJUSTMENTS 12/31/2011 (a)	ADJUSTED TEST YEAR 12/31/2011	
	PRODUCTION:				
1.	GROSS PLANT	$ 419,334,350	$ -	$ 419,334,350	
2.	ACCUMULATED DEPRECIATION	(201,163,209)	(3,398,294)	(204,561,503)	
3.	NET PLANT	218,171,141	(3,398,294)	214,772,847	
	TRANSMISSION:				
4.	GROSS PLANT	6,107,366	-	6,107,366	
5.	ACCUMULATED DEPRECIATION	(1,941,510)	-	(1,941,510)	
6.	NET PLANT	4,165,856	-	4,165,856	
	GENERAL & INTANGIBLE:				
7.	GROSS PLANT	27,262,416	(13,238)	27,249,178	
8.	ACCUMULATED DEPRECIATION	(7,318,651)	-	(7,318,651)	
9.	NET PLANT	19,943,765	(13,238)	19,930,527	
9A.	RWIP	104,903	-	104,903	
10.	TOTAL GROSS PLANT	452,704,132	(13,238)	452,690,894	(b)
11.	TOTAL ACC DEP. & RWIP	(210,318,467)	(3,398,294)	(213,716,761)	
12.	ACCUMULATED AMORTIZATION	(6,428,568)	166,973	(6,261,595)	
13.	TOTAL ACCUM DEPREC. & AMORT.	(216,747,035)	(3,231,321)	(219,978,356)	(b)
14.	TOTAL NET PLANT	$ 235,957,097	$ (3,244,559)	$ 232,712,538	(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
6/26/2012

LINE NO.		ACTUAL AT TEST YEAR 12/31/2011	PRO FORMA ADJUSTMENTS 12/31/2011	ADJUSTED TEST YEAR 12/31/2011
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	26,371,847	(b)
3.	MATERIALS AND SUPPLIES	8,379,202	(c)
4.	PREPAYMENTS	0	(d)
5	TOTAL WORKING CAPITAL	$ 34,751,049	(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.	JANUARY	$ 26,453,614	$ 26,453,614	
2.	FEBRUARY	26,144,341	26,144,341	
3.	MARCH	27,435,479	27,435,479	
4.	APRIL	26,940,099	26,940,099	
5.	MAY	28,368,607	28,368,607	
6.	JUNE	28,783,268	28,783,268	
7.	JULY	27,670,331	27,670,331	
8.	AUGUST	25,727,512	25,727,512	
9.	SEPTEMBER	25,993,940	25,993,940	
10.	OCTOBER	25,656,287	25,656,287	
11.	NOVEMBER	25,064,565	25,064,565	
12.	DECEMBER	22,224,115	22,224,115	
13.	TOTAL	$ 316,462,158	$ 316,462,158	
14.	12-MONTH AVERAGE		$ 26,371,847	(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.	DECEMBER (Prior Yr)	$	8,360,203		
2.	JANUARY		8,177,520	$	8,268,862
3.	FEBRUARY		8,186,090		8,181,805
4.	MARCH		7,884,199		8,035,145
5.	APRIL		8,122,477		8,003,338
6.	MAY		8,359,171		8,240,824
7.	JUNE		8,655,448		8,507,310
8.	JULY		8,288,393		8,471,921
9.	AUGUST		8,452,590		8,370,492
10.	SEPTEMBER		8,502,312		8,477,451
11.	OCTOBER		8,445,717		8,474,015
12.	NOVEMBER		8,900,636		8,673,177
13.	DECEMBER		8,791,547		8,846,092
14.	TOTAL	$	100,766,100	$	100,550,428
15.	12-MONTH AVERAGE			$	8,379,202 (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.	DECEMBER (Prior Yr)	$ -	$ -	$ -
2.	JANUARY	-	-	-
3.	FEBRUARY	-	-	-
4.	MARCH	-	-	-
5.	APRIL	-	-	-
6.	MAY	-	-	-
7.	JUNE	-	-	-
8.	JULY	-	-	-
9.	AUGUST	-	-	-
10.	SEPTEMBER	-	-	-
11.	OCTOBER	-	-	-
12.	NOVEMBER	-	-	-
13.	DECEMBER	-	-	-
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 12/31/2011 (a) (c)	RECLASSIFIED ADJUST. (b)	RECL TEST YR 12/31/2011
	REVENUES:			
1.	CLASS A MEMBERS	$ 151,931,983	$ (289,161)	$ 151,642,822
2.	FUEL ADJUSTMENT	3,567,157	-	3,567,157
3.	NON-CLS A, NON-FIRM & NON-MEM	5,855,043	-	5,855,043
4.	TOTAL ELECTRIC REVENUE:	161,354,183	(289,161)	161,065,022
5.	OTHER OPERATING REVENUE	8,314,147	(2,850,730)	5,463,417
6.	TOTAL OPERATING REVENUE	169,668,330	(3,139,891)	166,528,439
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	77,797,325	(313,698)	77,483,627
8.	PRODUCTION - STEAM A/C 500	4,706,859	-	4,706,859
9.	A/C 502	4,381,006	(1,413,609)	2,967,397
10.	A/C 503		-	-
11.	A/C 504		-	-
12.	A/C 505	1,645,798	(420,565)	1,225,233
13.	A/C 506 & 509	884,983	-	884,983
14.	A/C 507		-	-
15.	A/C 508		-	-
16.	PRODUCTION - OTHER - A/C 546	184,413	-	184,413
17.	A/C 548	551,193	(420,658)	130,535
18.	A/C 549	29,906	-	29,906
19.	A/C 550		-	-
	OTHER POWER SUPPLY			
20.	DEMAND A/C 555	3,262,451	-	3,262,451
21.	ENERGY A/C 555	13,533,831	-	13,533,831
22.	A/C 556	3,246,651	(124,858)	3,121,793
23.	A/C 557	75,351	-	75,351
24.	TRANSMISSION	9,249,224	(2,725,872)	6,523,352
25.	ADMINISTRATIVE & GENERAL	10,898,663	9,682	10,908,345
26.	TOTAL OPERATIONS	130,447,654	(5,409,578)	125,038,076
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	1,500,521	-	1,500,521
28.	A/C 511	40,104	-	40,104
29.	A/C 512	9,749,499	-	9,749,499
30.	A/C 513	1,380,730	-	1,380,730
31.	A/C 514	2,209,310	-	2,209,310
32.	A/C 515		-	-
33.	PRODUCTION - OTHER - A/C 551	58,799	-	58,799
34.	A/C 552	5,489	-	5,489
35.	A/C 553	1,088,452	-	1,088,452
36.	A/C 554	96,352	-	96,352
37.	TRANSMISSION	3,301	-	3,301
38.	GENERAL PLANT	1,172,320	-	1,172,320
39.	TOTAL MAINTENANCE	17,304,877	-	17,304,877

Arizona Electric Power Cooperative, Inc.

Reclassified Year End Income Statement

LINE NO.		PER BOOKS 12/31/2011 (a) (c)	RECLASSIFIED ADJUST. (b)	RECL TEST YR 12/31/2011
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	9,951,210	-	9,951,210
41.	ACC GROSS REVENUE TAXES		-	-
42.	TAXES		2,269,687	2,269,687
43.	TOTAL OTHER	9,951,210	2,269,687	12,220,897
44.	TOTAL OPERATING EXPENSES	157,703,741	(3,139,891)	154,563,850
45.	ELECTRIC OPERATING MARGINS	11,964,589	-	11,964,589
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	10,518,102	-	10,518,102
47.	INTEREST CHARGES TO CONSTR	(27,664)	-	(27,664)
48.	OTHER INTEREST EXPENSE	448,729	-	448,729
49.	OTHER DEDUCTIONS	196,280	-	196,280
50.	TOTAL INTEREST & OTHER DEDUCTIONS	11,135,447	-	11,135,447
51.	OPERATING MARGINS	829,142	-	829,142
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	438,715	-	438,715
53.	AFUDC		-	-
54.	OTHER NONOPERATING INCOME	587,331	-	587,331
55.	TOTAL OTHER NON OPERATING INCOME	1,026,046	-	1,026,046
55a.	EXTRAORDINARY ITEMS	-	-	-
56.	NET INCOME (MARGINS)	$ 1,855,188	$ -	$ 1,855,188

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 12/31/2011 (c)	PRO FORMA ADJUST. (a)	ADJ TEST YR 12/31/2011 (b)
	REVENUES:			
1.	CLASS A MEMBERS	$ 151,642,822	$ 1,440,980	$ 153,083,802
2.	FUEL ADJUSTMENT	3,567,157	(1,726,088)	1,841,069
3.	NON-CLS A, NON-FIRM & NON-MEM	5,855,043	(2,951,958)	2,903,085
4.	TOTAL ELECTRIC REVENUE:	161,065,022	(3,237,066)	157,827,956
5.	OTHER OPERATING REVENUE	5,463,417	333,227	5,796,644
6.	TOTAL OPERATING REVENUE	166,528,439	(2,903,839)	163,624,600
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	77,483,627	(12,200,214)	65,283,413
8.	PRODUCTION - STEAM A/C 500	4,706,859	(167,132)	4,539,727
9.	A/C 502	2,967,397	(92,646)	2,874,751
10.	A/C 503	-	-	-
11.	A/C 504	-	-	-
12.	A/C 505	1,225,233	(52,277)	1,172,956
13.	A/C 506 & 509	884,983	(14,905)	870,078
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	184,413	(6,521)	177,892
17.	A/C 548	130,535	(712)	129,823
18.	A/C 549	29,906	(493)	29,413
19.	A/C 550	-	-	-
	OTHER POWER SUPPLY			
20.	- DEMAND A/C 555	3,262,451	529,500	3,791,951
21.	- ENERGY A/C 555	13,533,831	-	13,533,831
22.	A/C 556	3,121,793	387,676	3,509,469
23.	A/C 557	75,351	-	75,351
24.	TRANSMISSION	6,523,352	5,856,312	12,379,664
25.	ADMINISTRATIVE & GENERAL	10,908,345	(2,391,719)	8,516,626
26.	TOTAL OPERATIONS	125,038,076	(8,153,131)	116,884,945
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	1,500,521	(63,455)	1,437,066
28.	A/C 511	40,104	(20,548)	19,556
29.	A/C 512	9,749,499	(643,133)	9,106,366
30.	A/C 513	1,380,730	(492,688)	888,042
31.	A/C 514	2,209,310	(72,086)	2,137,224
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	58,799	(2,466)	56,333
34.	A/C 552	5,489	(219)	5,270
35.	A/C 553	1,088,452	(86,157)	1,002,295
36.	A/C 554	96,352	(2,795)	93,557
37.	TRANSMISSION	3,301	(110)	3,191
38.	GENERAL PLANT	1,172,320	(4,877)	1,167,443
39.	TOTAL MAINTENANCE	17,304,877	(1,388,534)	15,916,343

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

LINE NO.		RECL TEST YR 12/31/2011 (c)	PRO FORMA ADJUST. (a)	ADJ TEST YR 12/31/2011 (b)
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 9,951,210	$ 3,398,294	$ 13,349,504
41.	ACC GROSS REVENUE TAXES	-	-	-
42.	TAXES	2,269,687	-	2,269,687
43.	TOTAL OTHER	12,220,897	3,398,294	15,619,191
44.	TOTAL OPERATING EXPENSES	154,563,850	(6,143,371)	148,420,479
45.	ELECTRIC OPERATING MARGINS	11,964,589	3,239,532	15,204,121
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	10,518,102	(1,236,231)	9,281,871
47.	INTEREST CHARGES TO CONSTRUCTION	(27,664)	-	(27,664)
48.	OTHER INTEREST EXPENSE	448,729	-	448,729
49.	OTHER DEDUCTIONS	196,280	(153,735)	42,545
50.	TOTAL INTEREST & OTHER DEDUCTIONS	11,135,447	(1,389,966)	9,745,481
51.	OPERATING MARGINS	829,142	4,629,498	5,458,640
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	438,715	-	438,715
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	587,331	-	587,331
55.	TOTAL OTHER NON OPERATING INCOME	1,026,046	-	1,026,046
55a.	EXTRAORDINARY ITEMS	-	-	-
56.	NET INCOME (MARGINS)	$ 1,855,188	4,629,498	6,484,686

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	$ -	$ (289,161)	$ -	$ -	$ (289,161)
2.	FUEL ADJUSTMENT	-		-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	-		-	-	-
4.	TOTAL ELECTRIC	-	(289,161)	-	-	(289,161)
5.	OTHER OPERATING REVENUE	(2,850,730)		-	-	(2,850,730)
6.	TOTAL OPERATING REVENUE	(2,850,730)	(289,161)	-	-	(3,139,891)
	OPERATING EXPENSES:					
	OPERATIONS					
7.	PRODUCTION -FUEL A/C 501 & 547	-		(313,698)	-	(313,698)
8.	PRODUCTION - STEAM A/C 500	-		-	-	-
9.	A/C 502	-		-	(1,413,609)	(1,413,609)
10.	A/C 503	-		-	-	-
11.	A/C 504	-		-	-	-
12.	A/C 505	-		-	(420,565)	(420,565)
13.	A/C 506 & 509	-		-	-	-
14.	A/C 507	-		-	-	-
15.	A/C 508	-		-	-	-
16.	PRODUCTION - OTHER - A/C 546	-		-	-	-
17.	A/C 548	-		-	(420,658)	(420,658)
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	(124,858)		-	-	(124,858)
23.	A/C 557	-		-	-	-
24.	TRANSMISSION	(2,725,872)		-	-	(2,725,872)
25.	ADMINISTRATIVE & GENERAL	-	(289,161)	313,698	(14,855)	9,682
26.	TOTAL OPERATIONS	(2,850,730)	(289,161)	-	(2,269,687)	(5,409,578)
	MAINTENANCE					
27.	PRODUCTION - STEAM - A/C S10	-		-	-	-
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 PROPERTY TAX RECLASS.	TOTAL RECLASS.
	OTHER:					
40.	DEPRECIATION & AMORTIZATION	$ -		$ -	$ -	$ -
41.	ACC GROSS REVENUE TAXES	-		-	-	-
42.	TAXES	-		-	2,269,687	2,269,687
43.	TOTAL OTHER	-		-	2,269,687	2,269,687
44.	TOTAL OPERATING EXPENSES	(2,850,730)	(289,161)	-	-	(3,139,891)
45.	ELECTRIC OPERATING MARGINS	-		-	-	-
	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	-	-	-	-	-
	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)	$ -	$ -	$ -	$ -	$ -

SUPPORTING SCHEDULES:

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

Arizona Electric Power Cooperative, Inc.

Income Statement Pro-Forma Adjustments

LINE NO.		1 ED2 SALES CONTRACT EXPIR ADJUSTMENT	2 COAL COST ADJUSTMENT	3 FIXED GAS CHARGES ADJUSTMENT	4 PAYROLL & PAY OVERHEADS ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ -	$ -
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	(2,951,958)	-		
4.	TOTAL ELECTRIC	(2,951,958)	-	-	-
5.	OTHER OPERATING REVENUE	-	-	-	-
6.	TOTAL OPERATING REVENUE	(2,951,958)	-	-	-
	OPERATING EXPENSES:				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	(1,184,434)	(10,967,627)	(48,153)	-
8.	PRODUCTION - STEAM A/C 500	-	-	-	(167,132)
9.	A/C 502	-	-	-	(37,646)
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	-	-	(52,277)
13.	A/C 506 & 509	-	-	-	(14,905)
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	(6,521)
17.	A/C 548	-	-	-	(712)
18.	A/C 549	-	-	-	(493)
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				
20.	- DEMAND A/C 555	-	-	-	-
21.	- ENERGY A/C 555	-		-	-
22.	A/C 556	-	-	-	(482,602)
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	(369,888)		-	-
25.	ADMINISTRATIVE & GENERAL	-	-	-	(1,259,387)
26.	TOTAL OPERATIONS	(1,554,322)	(10,967,627)	(48,153)	(2,021,675)
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	-	-	(63,455)
28.	A/C 511	-	-	-	(548)
29.	A/C 512	-	-	-	(92,553)
30.	A/C 513	-	-	-	(29,097)
31.	A/C 514	-	-	-	(56,715)
32.	A/C 515	-	-	-	-
33.	PRODUCTION - OTHER - A/C 551	-	-	-	(2,466)
34.	A/C 552	-	-	-	(219)
35.	A/C 553	-	-	-	(15,453)
36.	A/C 554	-	-	-	(2,795)
37.	TRANSMISSION	-	-	-	(110)
38.	GENERAL PLANT	-	-	-	(4,877)
39.	TOTAL MAINTENANCE	-	-	-	(268,288)

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		1 ED2 SALES CONTRACT EXPIR ADJUSTMENT	2 COAL COST ADJUSTMENT	3 FIXED GAS CHARGES ADJUSTMENT	4 PAYROLL & PAY OVERHEADS ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ -
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	-
43.	TOTAL OTHER	-	-	-	-
44.	TOTAL OPERATING EXPENSES	(1,554,322)	(10,967,627)	(48,153)	(2,289,963)
45.	ELECTRIC OPERATING MARGINS	(1,397,636)	10,967,627	48,153	2,289,963
	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	(1,397,636)	10,967,627	48,153	2,289,963
	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)	$ (1,397,636)	$ 10,967,627	$ 48,153	$ 2,289,963

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

LINE NO.		5 MAINT. OUTAGE OVERHAUL ADJUSTMENT	6 AEPCO P-T-P WHEELING ADJUSTMENT	7 SCHEDULING & TRADING SVCS ADJUSTMENT	8 APM REGIONAL TRADING CENTER ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ -	$ -
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	-	-	-	-
4.	TOTAL ELECTRIC	-	-	-	-
5.	OTHER OPERATING REVENUE	-	-	333,227	-
6.	TOTAL OPERATING REVENUE	-	-	333,227	-
	OPERATING EXPENSES:				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	-	-	-	-
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	-	-	-	-
21.	- ENERGY A/C 555	-	-	-	-
22.	A/C 556	-	-	-	870,278
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	-	6,226,200	-	-
25.	ADMINISTRATIVE & GENERAL	-	-	-	-
26.	TOTAL OPERATIONS	$ -	$ 6,226,200	$ -	$ 870,278
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	-	-	-
28.	A/C 511	-	-	-	-
29.	A/C 512	(379,117)	-	-	-
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	(32,129)	-	-	-
36.	A/C 554	-	-	-	-
37.	TRANSMISSION	-	-	-	-
38.	GENERAL PLANT	-	-	-	-
39.	TOTAL MAINTENANCE	(411,246)	-	-	-

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		5 MAINT. OUTAGE OVERHAUL ADJUSTMENT	6 AEPCO P-T-P WHEELING ADJUSTMENT	7 SCHEDULING & TRADING SVCS ADJUSTMENT	8 APM REGIONAL TRADING CENTER ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	-	-	-	-
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	-
43.	TOTAL OTHER	-	-	-	-
44.	TOTAL OPERATING EXPENSES	(411,246)	6,226,200	-	870,278
45.	ELECTRIC OPERATING MARGINS	411,246	(6,226,200)	333,227	(870,278)
	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	411,246	(6,226,200)	333,227	(870,278)
	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)	$ 411,246	$ (6,226,200)	$ 333,227	$ (870,278)

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 COST CUTTING PROGRAM ADJUSTMENT	10 AMORTIZE RATE CASE EXPENSES ADJUSTMENT	11 CALIF. PARTIES LEGAL COST 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	(55,000)	0	0	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	529,500
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	80,000	(1,212,332)	0
26.	TOTAL OPERATIONS	(55,000)	80,000	(1,212,332)	529,500
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	0	0	0	0
28.	A/C 511	(20,000)	0	0	0
29	A/C 512	(171,463)	0	0	0
30.	A/C 513	(463,591)	0	0	0
31	A/C 514	(15,371)	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	0	0	0	0
35.	A/C 553	(38,575)	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	$ (709,000)	$ -	$ -	$ -

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		9 COST CUTTING PROGRAM ADJUSTMENT	10 AMORTIZE RATE CASE EXPENSES ADJUSTMENT	11 CALIF. PARTIES LEGAL COST ADJUSTMENT	12 SOUTHPOINT PPA CAPACITY ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	0	0	0	0
41.	ACC GROSS REVENUE TAXES	0	0	0	0
42.	TAXES	0	0	0	0
43.	TOTAL OTHER	0	0	0	0
44.	TOTAL OPERATING EXPENSES	(764,000)	80,000	(1,212,332)	529,500
45.	ELECTRIC OPERATING MARGINS	764,000	(80,000)	1,212,332	(529,500)
	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	0	0	0
49.	OTHER DEDUCTIONS	0	0	0	0
50.	TOTAL INTEREST & OTHER DEDUCTIONS	0	0	0	0
51.	OPERATING MARGINS	764,000	(80,000)	1,212,332	(529,500)
	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)	$ 764,000	$ (80,000)	$ 1,212,332	$ (529,500)

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 Adjustment

LINE NO.		13 DEPRECIATION RATES ADJUSTMENT	14 CUT DEBT REFINANCING ADJUSTMENT	15 INTEREST ANNUALIZATION ADJUSTMENT	16 REVENUE SYNCHRONIZATION ADJUSTMENT	TOTAL PRO-FORMA ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ -	$ 1,440,980	$ 1,440,980
2.	FUEL ADJUSTMENT	-	-	-	(1,726,088)	(1,726,088)
3.	NON-CLS A, NON-FIRM & NON-ME	-	-	-	-	(2,951,958)
4.	TOTAL ELECTRIC	-	-	-	(285,108)	(3,237,066)
5.	OTHER OPERATING REVENUE	-	-	-	-	333,227
6.	TOTAL OPERATING REVENUE	-	-	-	(285,108)	(2,903,839)
	OPERATING EXPENSES					
	OPERATIONS					
7.	PRODUCTION -FUEL A/C 501 & 547	-	-	-	-	(12,200,214)
8.	PRODUCTION - STEAM A/C 500	-	-	-	-	(167,132)
9.	A/C 502	-	-	-	-	(92,646)
10.	A/C 503	-	-	-	-	-
11.	A/C 504	-	-	-	-	-
12.	A/C 505	-	-	-	-	(52,277)
13.	A/C 506 & 509	-	-	-	-	(14,905)
14.	A/C 507	-	-	-	-	-
15.	A/C 508	-	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	-	(6,521)
17.	A/C 548	-	-	-	-	(712)
18.	A/C 549	-	-	-	-	(493)
19.	A/C 550	-	-	-	-	-
	OTHER POWER SUPPLY					-
20.	- DEMAND A/C 555	-	-	-	-	529,500
21.	- ENERGY A/C 555	-	-	-	-	-
22.	A/C 556	-	-	-	-	387,676
23.	A/C 557	-	-	-	-	-
24.	TRANSMISSION	-	-	-	-	5,856,312
25.	ADMINISTRATIVE & GENERAL	-	-	-	-	(2,391,719)
26.	TOTAL OPERATIONS	-	-	-	-	(8,153,131)
	MAINTENANCE					
27.	PRODUCTION - STEAM - A/C 510	-	-	-	-	(63,455)
28.	A/C 511	-	-	-	-	(20,548)
29	A/C 512	-	-	-	-	(643,133)
30.	A/C 513	-	-	-	-	(492,688)
31	A/C 514	-	-	-	-	(72,086)
32	A/C 515	-	-	-	-	-
33	PRODUCTION - OTHER - A/C 551	-	-	-	-	(2,466)
34.	A/C 552	-	-	-	-	(219)
35.	A/C 553	-	-	-	-	(86,157)
36.	A/C 554	-	-	-	-	(2,795)
37.	TRANSMISSION	-	-	-	-	(110)
38.	GENERAL PLANT	-	-	-	-	(4,877)
39.	TOTAL MAINTENANCE	$ -	$ -	$ -	$ -	$ (1,388,534)

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

LINE NO.		13 DEPRECIATION RATES ADJUSTMENT	13 CUT DEBT REFINANCING ADJUSTMENT	14 INTEREST ANNUALIZATION ADJUSTMENT	15 REVENUE SYNCHRONIZATION ADJUSTMENT	TOTAL PRO-FORMA ADJUSTMENTS
	OTHER:					
40.	DEPRECIATION & AMORTIZATION	$ 3,398,294	$ -	$ -	$ -	$ 3,398,294
41.	ACC GROSS REVENUE TAXES	-	-	-	-	-
42.	TAXES	-	-	-	-	-
43.	TOTAL OTHER	3,398,294	-	-	-	3,398,294
44.	TOTAL OPERATING EXPENSES	3,398,294	-	-	-	(6,143,371)
45.	ELECTRIC OPERATING MARGINS	(3,398,294)	-	-	(285,108)	3,239,532
	INTEREST & OTHER DEDUCTIONS:					
46.	INTEREST ON LONG-TERM DEBT		(531,768)	(704,463)	-	(1,236,231)
47.	INTEREST CHARGES TO CONSTR			-	-	-
48.	OTHER INTEREST EXPENSE			-	-	-
49.	OTHER DEDUCTIONS	(153,735)		-	-	(153,735)
50.	TOTAL INTEREST & OTHER DEDUCTIONS	(153,735)	(531,768)	(704,463)	-	(1,389,966)
51.	OPERATING MARGINS	(3,244,559)	531,768	704,463	(285,108)	4,629,498
	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)	$ (3,244,559)	$ 531,768	$ 704,463	$ (285,108)	$ 4,629,498

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
6/26/2012

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	0.00037
4.	TOTAL TAX PERCENTAGE **	0.00037
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.

SCHEDULE D-1

Summary Cost of Capital

6/26/2012

END OF ACTUAL TEST YEAR 12/31/2011

LINE NO.	INVESTED CAPITAL		AMOUNT (b)	%	COST RATE	COMPOSITE (b)
1.	LONG-TERM DEBT (a)	$	216,731,512	98.31%	4.87%	4.78%
2.	SHORT-TERM DEBT (a)		3,721,518	1.69%	0.38%	0.01%
3.	TOTAL	$	220,453,030	100.00%		4.79%

END OF PROJECTED YEAR 12/31/2012

	INVESTED CAPITAL		AMOUNT (b)	%	COST RATE	COMPOSITE (b)
4.	LONG-TERM DEBT (a)	$	200,063,388	98.17%	4.62%	4.53%
5.	SHORT-TERM DEBT (a)		3,721,518	1.83%	0.38%	0.01%
6.	TOTAL	$	203,784,906	100.00%		4.54%

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
6/26/2012

LINE NO.		END OF ACTUAL TEST YEAR 12/31/2011			END OF PROJECTED YEAR 12/31/2012		
		OUTSTANDING	FACE RATE	ANNUAL INTEREST	OUTSTANDING	FACE RATE	ANNUAL INTEREST
1.	FFB DEBT	$ 155,261,178	5.140%	$ 7,980,425	$ 157,260,681	5.027%	$ 7,905,508
4.	CFC SERIES 1994A BONDS	13,484,574	1.000%	134,846	12,810,345	1.000%	128,103
5.	CENTRAL BANK FOR COOPERATIVES	15,110,139	7.740%	1,169,525	-		-
6.	NRUCFC	32,875,621	3.388%	1,113,826	29,992,362	3.714%	1,113,826
7.	REGULATORY ASSET			148,000	-	-	91,000
8.	TOTAL LONG-TERM (b)	$ 216,731,512	4.866%	$ 10,546,622	$ 200,063,388	4.618%	$ 9,238,437
9.	COST RATE (b)			4.866%			4.618%
	SHORT TERM:	3,721,518	0.377%	$ 14,030	3,721,518	0.377%	$ 14,030
10.	SHORT-TERM DEBT (b)	$ 3,721,518	0.377%	$ 14,030	$ 3,721,518		$ 14,030
11.	COST RATE (b)			0.377%			0.377%

LINE NO.		END OF YEAR 12/31/2009			END OF YEAR 12/31/2010		
		OUTSTANDING (a)	FACE RATE	ANNUAL INTEREST	OUTSTANDING (a)	FACE RATE	ANNUAL INTEREST
	LONG-TERM DEBT:						
1.	FFB DEBT	$ 135,222,860	4.995%	$ 6,754,382	$ 142,689,655	5.374%	$ 7,668,142
2.	REA DEBT	109,266	5.000%	5,463	-	0.000%	-
3	CFC SERIES 1994A BONDS	14,765,609	3.100%	457,734	14,158,803	1.480%	209,550
4.	CENTRAL BANK FOR COOPERATIVES	19,351,712	7.740%	1,497,823	17,360,715	7.740%	1,343,719
5.	NRUCFC	10,728,119	4.940%	529,969	22,686,650	4.917%	1,115,503
6.	REGULATORY ASSET	-	0.000%	284,000	-	0.000%	222,000
7.	TOTAL LONG-TERM DEBT (b)	$ 180,177,566		$ 9,529,371	$ 196,895,823		$ 10,558,914
8.	COST RATE (b)			5.289%			5.363%
	SHORT TERM:	22,442,010	2.396%	$ 537,711	9,747,026	0.429%	$ 41,815
9.	SHORT-TERM DEBT (b)	$ 22,442,010		$ 537,711	$ 9,747,026		$ 41,815
10.	COST RATE (b)			2.396%			0.429%

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

RECAP SCHEDULES:
(b) A-3

Arizona Electric Power Cooperative, Inc.

SCHEDULE D-3

Cost Of Prefered Stock

6/26/2012

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

SCHEDULE D-4

Cost of Common Stock

6/26/2012

NOT APPLICABLE

E

Arizona Electric Power Cooperative, Inc.

Comparative Balance Sheets

LINE NO.		PER BOOKS 12/31/2011	PRIOR YEAR 12/31/2010	PRIOR YEAR 12/31/2009
	ASSETS			
	UTILITY PLANT:			
1.	UTILITY PLANT IN SERVICE	$ 452,704,132	$ 438,545,536	$ 426,909,628
2.	LESS: ACCUMULATED DEPRECIATION AND AMORTIZATION	(216,747,035)	(211,537,129)	(212,515,353)
3.	TOTAL UTILITY PLANT IN SERVICE	235,957,097	227,008,407	214,394,275
4.	CONSTRUCTION WORK IN PROGRESS	4,164,264	6,046,206	9,354,610
5.	PLANT HELD FOR FUTURE USE	2,538,392	2,538,392	2,538,392
6.	NET UTILITY PLANT (a)	242,659,753	235,593,005	226,287,277
	CURRENT ASSETS:			
7.	GENERAL FUND CASH	2,534,744	3,839,346	619,401
8.	TEMPORARY INVESTMENTS	117,188	8,710,728	106,512
9.	ACCOUNTS RECEIVABLE	15,871,787	15,326,265	21,921,581
10.	FUEL INVENTORY	22,224,115	26,305,517	36,491,912
11.	MATERIALS AND SUPPLIES	8,791,547	8,360,203	7,238,225
12.	PREPAYMENTS & OTHER CURRENT ASSETS	1,672,882	1,383,436	1,298,300
13.	NOTES RECEIVABLE-CURRENT	-	-	-
14.	OTHER	129,133	136,241	122,203
15.	TOTAL CURRENT ASSETS	51,341,396	64,061,736	67,798,134
	OTHER ASSETS:			
16.	INV - ASSOC ORG	17,200,577	14,604,250	12,960,258
17.	INVESTMENTS	27,346,639	3,981,212	3,084,134
18.	DEFERRED DEBITS	11,926,600	10,358,797	10,814,219
19.	UNAMORTIZED DEBT	159,901	209,675	269,519
20.	REGULATORY ASSETS	-	-	-
21.	TOTAL OTHER ASSETS	56,633,717	29,153,934	27,128,130
22.	TOTAL ASSETS	$ 350,634,866	$ 328,808,675	$ 321,213,541

Arizona Electric Power Cooperative, Inc.

Comparative Balance Sheets

LINE NO.		PER BOOKS 12/31/2011	PRIOR YEAR 12/31/2010	PRIOR YEAR 12/31/2009
	LIABILITIES & EQUITY			
	EQUITY: (c) (d)			
23.	PATRONAGE CAPITAL	$ 94,018,550	$ 84,514,994	$ 74,558,069
24.	UNALLOCATED MARGINS	1,855,191	9,503,559	9,956,925
25.	TOTAL EQUITY	95,873,741	94,018,553	84,514,994
	LIABILITIES:			
	LONG-TERM DEBT: (b)			
26.	FFB DEBT	155,325,984	142,689,655	135,222,860
27.	REA DEBT	-	-	109,266
28.	PAYMENTS UNAPPLIED	(64,806)	(1,527,713)	(127,909)
29.	CFC 1994A BONDS	13,484,574	14,158,803	14,765,609
30.	COOPERATIVE UTILITY TRUST	15,110,139	17,360,715	19,351,712
31.	NRUCFC	41,620,487	22,686,650	10,728,119
32.	LESS CURRENT MATURITIES	(9,496,529)	(7,506,642)	(7,043,314)
33.	TOTAL LONG-TERM DEBT	215,979,849	187,861,468	173,006,343
34.	OBLIGATIONS UNDER CAPITAL LEASES	1,075,072	4,088,429	5,486,601
	CURRENT LIABILITIES:			
35.	MEMBER ADVANCES & NOTES	3,721,518	9,747,026	22,442,010
36.	ACCOUNTS PAYABLE	10,605,752	13,183,632	16,964,576
37.	ACCRUED TAXES	1,469,864	1,705,992	1,778,015
38.	ACCRUED INTEREST	2,666,890	2,586,150	699,972
39.	CURRENT LIABILITY - OTHER	1,798,261	1,046,579	768,648
40.	CURRENT MATURITIES OF LONG TERM DEBT	9,496,529	7,506,642	7,043,314
41.	TOTAL CURRENT LIABILITIES	29,758,814	35,776,021	49,696,535
42.	ACCUMULATED OPERATING PROVISIONS	2,472,291	2,172,974	1,901,195
				-
43.	DEFERRED CREDITS	5,475,099	4,891,230	7,237,873
44.	TOTAL LIABILITIES AND EQUITY	$ 350,634,866	$ 328,808,675	$ 321,843,541

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 12/31/2011 (b)	PRIOR YEAR 12/31/2010	PRIOR YEAR 12/31/2009
	REVENUES:			
1.	CLASS A MEMBERS	$ 151,931,983	$ 110,705,487	$ 111,376,114
2.	FUEL ADJUSTMENT	3,567,157	40,754,710	46,434,309
3.	NON-CIS A, N-FIRM & N-MEMB	5,855,043	41,468,995	39,029,682
4.	TOTAL ELECTRIC REVENUE	161,354,183	192,929,192	196,840,105
5.	OTHER OPERATING REVENUE	8,314,147	14,447,887	12,312,114
6.	TOTAL OPERATING REVENUE	169,668,330	207,377,079	209,152,219
	OPERATING EXPENSES			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	77,797,325	82,556,364	79,520,400
8.	PRODUCTION - STEAM A/C 500	4,706,859	5,356,741	6,124,537
9.	A/C 502	4,381,006	4,975,319	2,921,229
10.	A/C 503	-	-	-
11.	A/C 504	-	-	-
12.	A/C 505	1,645,798	1,039,277	742,673
13.	A/C 506	884,983	902,368	798,526
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	184,413	209,890	239,972
17.	A/C 548	551,193	636,390	638,223
18.	A/C 549	29,906	36,113	39,688
19.	A/C 550	-	-	-
	OTHER POWER SUPPLY	-		
20.	-DEMAND A/C 555	3,262,451	4,575,737	3,959,398
21.	- ENERGY A/C 555	13,533,831	28,757,932	34,427,407
22.	A/C 556	3,246,651	628,940	528,711
23.	A/C 557	75,351	1,842,719	1,794,867
24.	TRANSMISSION	9,249,224	16,083,174	16,190,844
25.	ADMINISTRATIVE & GENERAL	10,898,663	11,596,628	11,565,330
26.	TOTAL OPERATIONS	130,447,654	159,197,592	159,491,805
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	1,500,521	1,375,522	1,733,825
28.	A/C 511	40,104	147,136	48,905
29.	A/C 512	9,749,499	10,203,111	9,145,635
30.	A/C 513	1,380,730	1,813,875	2,373,201
31.	A/C 514	2,209,310	2,203,857	2,628,805
32.	A/C 515	-		-
33.	PRODUCTION - OTHER - A/C 551	58,799	53,918	67,957
34.	A/C 552	5,489	11,888	11,034
35.	A/C 553	1,088,452	1,668,990	2,024,133
36.	A/C 554	96,352	136,906	146,307
37.	TRANSMISSION	3,301	4,603	58,307
38.	GENERAL PLANT	1,172,320	1,199,858	377,946
39.	TOTAL MAINTENANCE	17,304,877	18,819,664	18,616,055

Arizona Electric Power Cooperative, Inc.

Comparative Income Statements

LINE NO.		ACTUAL TEST YEAR 12/31/2011 (b)	PRIOR YEAR 12/31/2010	PRIOR YEAR 12/31/2009
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 9,951,210	$ 9,367,223	$ 8,818,475
41.	ACC GROSS REVENUE TAXES	-	-	-
42.	TAXES	-	-	-
43.	TOTAL OTHER	9,951,210	9,367,223	8,818,475
44.	TOTAL OPERATING EXPENSES	157,703,741	187,384,479	186,926,335
45.	ELECTRIC OPERATING MARGINS	11,964,589	19,992,600	22,225,884
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	10,518,102	10,770,431	10,622,133
47.	INTEREST CHARGES TO CONSTR	(27,664)	(15,815)	(101,703)
48.	OTHER INTEREST EXPENSE	448,729	759,149	924,021
49.	OTHER DEDUCTIONS	196,280	80,079	2,413,330
50.	TOTAL INTEREST & OTHER DEDUCTIONS	11,135,447	11,593,844	13,857,781
51.	OPERATING MARGINS	829,142	8,398,756	8,368,103
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	438,715	421,969	317,305
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	587,331	682,831	1,271,517
55.	TOTAL OTHER NON OPERATING INCOME	1,026,046	1,104,800	1,588,822
55a.	EXTRAORDINARY ITEMS (Patronage Capital Credits	-	-	-
56.	NET INCOME (MARGINS) (c)	$ 1,855,188	$ 9,503,556	$ 9,956,925

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

6/26/2012

LINE NO.			PER BOOKS 12/31/2011	PRIOR YEAR 12/31/2010	PRIOR YEAR 12/31/2009
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1.	NET MARGIN	(a)	$ 1,855,188	$ 9,503,556	$ 9,956,925
	ADJUSTMENTS TO RECONCILE NET MARGIN TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES-				
2.	DEPREC. & AMORT.		9,951,210	9,367,223	8,818,475
3.	AMORTIZATION OF DEFERRED CHARGES		67,918	77,989	77,987
4.	AMORTIZATION OF OTHER DEFERRED CREDITS		(337,280)	(337,280)	(337,280)
	CHANGES IN ASSETS AND LIABILITIES				
5.	RESTRICTED CASH AND CASH EQUIVALENTS		(23,442,002)	247,422	2,716,937
6.	RECEIVABLES		1,491,427	33,489	3,763,067
7.	INVENTORIES		3,650,058	9,064,419	(17,710,939)
8.	DEFERRED DEBITS		(1,585,948)	533,694	(1,697,381)
9.	ACCOUNTS PAYABLE		(1,134,682)	(5,734,058)	3,295,348
10.	ACCRUED INTEREST PAYABLE		80,742	1,886,177	(25,323)
11.	OVER/UNDER RE3COVERED FUEL & PURCHASED POWER		(3,257,101)	7,080,534	2,527,849
12.	OTHER , NET		(1,280,003)	98,099	(2,157,868)
	NET CASH PROVIDED BY OPERATING ACTIVITIES	(b)	(13,940,473)	31,821,264	9,227,797
	CASH FLOWS FROM INVESTING ACTIVITIES:				
13.	CONSTRUCTION EXPENDITURES, NET (c)		(16,872,378)	(18,536,384)	(16,664,155)
14.	PURCHASE AND REDEMPTIONS, NET		(2,423,194)	(1,451,938)	2,255,806
15.	PATRONAGE CAPITAL RETIREMENT		-	-	-
16.	NET CASH USED IN INVESTING ACTIVITIES	(b)	(19,295,572)	(19,988,322)	(14,408,349)
	CASH FLOWS FROM FINANCING ACTIVITIES:				
17.	MEMBER ADVANCES, NET		(5,216,367)	(4,298,162)	283,032
18.	ISSUANCE OF LONG-TERM DEBT		55,789,411	31,750,360	36,204,375
19.	RETIREMENT OF LONG-TERM DEBT		(27,206,390)	(17,830,078)	(36,661,404)
20.	LINE OF CREDIT ACTIVITY, NET		-	(10,700,000)	5,300,000
21.	MEMBERSHIP FEES		-	-	-
22.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(b)	23,366,654	(1,077,880)	5,126,003
23.	NET DECREASE IN CASH AND CASH EQ.	(b)	(9,869,391)	10,755,062	(54,549)
24.	CASH AND CASH EQUIVALENTS, Beginning of Year		11,839,090	1,084,028	1,138,577
25.	CASH AND CASH EQUIVALENTS, End of Year		$ 1,969,699	$ 11,839,090	$ 1,084,028
	SUPPLEMENTAL DISCLOSURES:				
26.	CASH PAID FOR INTEREST, NET OF AMOUNT CAPITALIZED		$ 10,858,425	$ 9,627,589	$ 11,469,775

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

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

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-4

Statement of Change in Equity

6/26/2012

LINE NO.		PATRONAGE CAPITAL		UNALLOCATED MARGINS	
1.	BALANCE, DECEMBER 31, 2008	$ 57,202,299		$ 17,355,770	
2.	UNALLOCATED MARGINS CHANGE	17,355,770		(17,355,770)	
3.	NET EARNINGS (LOSS)			9,956,925	
4.	BALANCE, DECEMBER 31, 2009	74,558,069	(a)	9,956,925	
5.	UNALLOCATED MARGINS CHANGE	9,956,925		(9,956,922)	
6.	NET EARNINGS (LOSS)			9,503,556	
7.	BALANCE, DECEMBER 31, 2010	84,514,994		9,503,559	(a)
8	UNALLOCATED MARGINS CHANGE	9,503,556		(9,503,556)	
9	NET EARNINGS (LOSS)			1,855,188	
10	BALANCE, DECEMBER 31, 2011	$ 94,018,550	(a)	$ 1,855,191	(a)

SUPPORTING SCHEDULES:

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

Arizona Electric Power Cooperative, Inc.

Detail of Utility Plant

LINE NO.		END OF PRIOR YEAR 12/31/2010	NET ADDITIONS	ACTUAL TEST YEAR 12/31/2011	PRO FORMA ADJUSTMENTS (a)	ADJUSTED TEST YEAR 12/31/2011
	INTANGIBLE PLANT:					
1.	301 ORGANIZATION	$ 4,545	$ -	$ 4,545	$ -	$ 4,545
2.	114 ACQUISITION ADJUSTMENT	13,238	-	13,238	(13,238)	-
3.	302 FRANCHISE AND CONSENT	745	-	745	-	745
4.	303 MISC. INTANGIBLE PLANT	10,966,578	205,920	11,172,498	-	11,172,498
5.	SUBTOTAL INTANGIBLE	10,985,106	205,920	11,191,026	(13,238)	11,177,788
	STEAM PRODUCTION PLANT:					
6.	310 LAND AND LAND RIGHTS	8,653,186	-	8,653,186	-	8,653,186
7.	311 STRUCTURES AND IMPROVEMENTS	35,873,467	-	35,873,467	-	35,873,467
8.	312 BOILER EQUIPMENT	234,020,581	12,121,876	246,142,457	-	246,142,457
9.	314 TURBINE GENERATORS	60,733,085	1,095,318	61,828,403	-	61,828,403
10.	315 ACCESSORY ELEC. EQUIPMENT	18,256,524	391,916	18,648,440	-	18,648,440
11.	316 MISC. POWER EQUIPMENT	4,289,211	-	4,289,211	-	4,289,211
12.	317 ASSET RETIREMENT OBLIGATION	1,357,361	145,582	1,502,943	-	1,502,943
13.	SUBTOTAL STEAM PRODUCTION	363,183,415	13,754,692	376,938,107	-	376,938,107
	OTHER PRODUCTION PLANT:					
14.	340 LAND AND LAND RIGHTS	1,160	-	1,160	-	1,160
15.	341 STRUCTURES AND IMPROVEMENTS	718,636	-	718,636	-	718,636
16.	342 FUEL HLDRS PRODCRS & ACCES	2,805,026	-	2,805,026	-	2,805,026
17.	343 PRIME MOVERS	30,977,252	220,953	31,198,205	-	31,198,205
18.	344 GENERATORS	3,347,849	-	3,347,849	-	3,347,849
19.	345 ACCESSORY ELEC. EQUIPMENT	3,276,528	103,571	3,380,099	-	3,380,099
20.	346 MISC. POWER EQUIPMENT	915,030	-	915,030	-	915,030
21.	SUBTOTAL OTHER PRODUCTION	42,041,481	324,524	42,366,005	-	42,366,005
	TRANSMISSION PLANT:					
22.	350 LAND AND LAND RIGHTS	-	-	-	-	-
23.	352 STRUCTURES AND IMPROVEMENTS	-	-	-	-	-
24.	353 STATION EQUIPMENT	5,690,341	169,696	5,860,037	-	5,860,037
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	5,937,670	169,696	6,107,366	-	6,107,366

Arizona Electric Power Cooperative, Inc.
Detail of Utility Plant

LINE NO.		END OF PRIOR YEAR 12/31/2010		NET ADDITIONS	ACTUAL TEST YEAR 12/31/2011		PRO FORMA ADJUSTMENT (a)	ADJUSTED TEST YEAR 12/31/2011	
	GENERAL PLANT:								
30.	389 LAND AND LAND RIGHTS	$ 147,861		$ -	$ 147,861		$ -	$ 147,861	
31.	390ACCOUNTS390-399	16,219,765		(296,236)	15,923,529		-	15,923,529	
32.	SUBTOTAL GENERAL	16,367,626		(296,236)	16,071,390		-	16,071,390	
	COMPLETED CONST - UNCLASSIFIED								
33.	GENERAL PLANT	-		-	-		-	-	
34.	LINES	-		-	-		-	-	
35.	SUBSTATION	-		-	-		-	-	
36.	GENERATION - STEAM	30,238		-	30,238		-	30,238	
37.	GENERATION - IC	-		-	-		-	-	
38.	TOTAL COMPLETED	30,238		-	30,238		-	30,238	
39.	TOTAL PLANT IN SERVICE	438,545,536	(b) (c)	14,158,596	452,704,132	(b) (c)	(13,238)	452,690,894	(d)
	ACCUMULATED DEPRECIATION (d)								
40.	PRODUCTION	(197,790,235)		(3,372,974)	(201,163,209)		(3,398,294)	(204,561,503)	
41.	TRANSMISSION	(1,775,891)		(165,619)	(1,941,510)		-	(1,941,510)	
42.	RETIREMENTS	171,259		(66,356)	104,903		-	104,903	
43.	GENERAL	(7,216,436)		(102,215)	(7,318,651)		-	(7,318,651)	
44.	ELEC PLT IN SERVICE	-		-	-		-	-	
45.	TOTAL	(206,611,303)		(3,707,164)	(210,318,467)		(3,398,294)	(213,716,761)	
46.	ACCUMULATED AMORTIZATION	(4,925,826)		(1,502,742)	(6,428,568)		166,973	(6,261,595)	
47.	TOTAL ACCUM DEPREC. & AMORT.	(211,537,129)	(b)	(5,209,906)	(216,747,035)	(b)	(3,231,321)	(219,978,356)	(d)
48.	TOTAL UTILITY PLANT IN SERVICE	227,008,407		8,948,690	235,957,097	(d)	(3,244,559)	232,712,538	(d)
49.	CWIP	6,046,206	(b)	(1,881,942)	4,164,264	(b)	-	4,164,264	
50.	PLANT HELD FOR FUTURE USE	2,538,392		-	2,538,392	(b)	(2,538,392)	-	(e)
51.	TOTAL NET PLANT IN SERVICE	$ 235,593,005	(b)	$ 7,066,748	$ 242,659,753		$ (5,782,951)	$ 236,876,802	

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

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.		RECLASSIFY ACQ. ADJ. Adj. 1	PLANT HELD FUTURE USE ADJ. 2	DEPRECIATION ADJUSTMENT ADJ. 3	TOTAL
	INTANGIBLE PLANT:				
1.	301 ORGANIZATION	$ -	$ -	$ -	$ -
2.	114 ACQUISITION ADJUSTMENT	(13,238)	-	-	(13,238)
3.	302 FRANCHISE AND CONSENT	-	-	-	-
4.	303 MISC. INTANGIBLE PLANT	-	-	-	-
5.	SUBTOTAL INTANGIBLE	(13,238)	-	-	(13,238)
	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.		RECLASSIFY ACQ. ADJ. ADJ. 1	PLANT HELD FUTURE USE ADJ. 2	DEPRECIATION ADJUSTMENT ADJ. 3	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	(13,238)	-	-	(13,238)
	ACCUMULATED DEPRECIATION				
40.	PRODUCTION	-	-	(3,398,294)	(3,398,294)
41.	TRANSMISSION	-	-	-	-
42.	RETIREMENTS	-	-	-	-
43.	GENERAL	-	-	-	-
44.	ELEC PLT IN SERVICE	-	-	-	-
45.	TOTAL	-	-	(3,398,294)	(3,398,294)
46.	ACCUMULATED AMORTIZATION	13,238	-	153,735	166,973
47.	TOTAL ACCUM DEPREC. & AMORT.	13,238	-	(3,244,559)	(3,231,321)
48.	NET PLANT IN SERVICE	-	-	(3,244,559)	(3,244,559)
49.	CWIP	-	-	-	-
50.	PLANT HELD FOR FUTURE USE	-	(2,538,392)	-	(2,538,392)
51.	TOTAL NET PLANT	$ -	$ (2,538,392)	$ (3,244,559)	$ (5,782,951)

Arizona Electric Power Cooperative, Inc. SCHEDULE E-6

Statement of Change in Equity **6/26/2012**

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-7

Operating Statistics

6/26/2012

LINE NO.	ELECTRIC STATISTICS	UNADJUSTED TEST YEAR ENDED 12/31/2011	PRIOR YEAR ENDED 12/31/2010	PRIOR YEAR ENDED 12/31/2009
	KWH SALES:			
1.	CLASS A MEMBERS	2,327,819,816	2,176,600,696	2,201,798,423
2.	OTHER FIRM CONTRACTS	39,995,646	531,047,220	487,798,654
3.	TOTAL	2,367,815,462	2,707,647,916	2,689,597,077
	AVERAGE NO. CUSTOMERS:			
4.	CLASS A MEMBERS	6	6	6
5.	OTHER FIRM CONTRACTS	1	2	2
6.	TOTAL	7	8	8
	AVERAGE KWH USE:			
7.	CLASS A MEMBERS	387,969,969	362,766,783	366,966,404
8.	OTHER FIRM CONTRACTS	39,995,646	265,523,610	243,899,327
9.	TOTAL	427,965,615	628,290,393	610,865,731
10.	KWH PRODUCTION EXPENSE (a)	$ 91,331,156	$ 111,314,296	$ 113,947,807

SUPPORTING SCHEDULES:
(a) E-2, Page 1, Line 7 + Line 21

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-8

Taxes Charged to Operations

6/26/2012
2/29/11

LINE NO.	DESCRIPTION:	PER BOOKS 12/31/2011	PRIOR YEAR ENDED 12/31/2010	PRIOR YEAR ENDED 12/31/2009
	FEDERAL TAXES:			
1.	PAYROLL ESTIMATED	$ 380,756	$ 599,421	$ 669,444
	FEDERAL INCOME	-	-	-
	TOTAL FEDERAL TAXES	380,756	599,421	669,444
	STATE TAXES:			
2.	PAYROLL ESTIMATED	46,922	75,456	109,414
3.	PROPERTY	2,589,676	2,825,205	2,889,410
4.	STATE INCOME	50	50	50
5.	CALIFORNIA FRANCHISE TAX	1,071	800	908
6.	PAYROLL ESTIMATED	$ 2,637,719	$ 2,901,511	$ 2,999,782

SEE FINANCIAL STATEMENTS

F

Arizona Electric Power Cooperative, Inc.

Projected Income Statement / Present and Proposed Rates

SCHEDULE F-1
Page 1 of 2
6/26/2012

LINE NO.		-ACTUAL- TESTYEAR 12/31/2011	-ADJ. TEST YEAR- PRESENT RATES 12/31/2011	PROPOSED RATES 12/31/2011
	REVENUES:			
1.	CLASS A MEMBERS	$ 151,931,983	$ 153,083,802	$ 150,397,406
2.	FUEL ADJUSTMENT	3,567,157	1,841,069	-
3.	NON-CIS A, N-FIRM & N-MEMB	5,855,043	2,903,085	2,903,085
4.	TOTAL ELECTRIC REVENUE	161,354,183	157,827,956	153,300,491
5	OTHER OPERATING REVENUE	8,314,147	5,796,644	5,796,644
6.	TOTAL OPERATING REVENUE (b)	169,668,330	163,624,600	159,097,135
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	77,797,325	65,283,413	65,283,413
8.	PRODUCTION - STEAM A/C 500	4,706,859	4,539,727	4,539,727
9.	A/C 502	4,381,006	2,874,751	2,874,751
10.	A/C 503	-	-	-
1L	A/C 504	-	-	-
12.	A/C 505	1,645,798	1,172,956	1,172,956
13.	A/C 506	884,983	870,078	870,078
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	184,413	177,892	177,892
17.	A/C 548	551,193	129,823	129,823
18.	A/C S49	29,906	29,413	29,413
19.	A/C 550	-	-	-
	OTHER POWER SUPPLY	-	-	-
20.	-DEMAND A/C 555	3,262,451	3,791,951	3,791,951
21.	- ENERGY A/C 555	13,533,831	13,533,831	13,533,831
22.	A/C 556	3,246,651	3,509,469	3,509,469
23.	A/C 557	75,351	75,351	75,351
24.	TRANSMISSION	9,249,224	12,379,664	12,379,664
25.	ADMINISTRATIVE & GENERAL	10,898,663	8,516,626	8,516,626
26.	TOTAL OPERATIONS	130,447,654	116,884,945	116,884,945
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	1,500,521	1,437,066	1,437,066
28.	A/C 511	40,104	19,556	19,556
29.	A/C 512	9,749,499	9,106,366	9,106,366
30.	A/C 513	1,380,730	888,042	888,042
31.	A/C 514	2,209,310	2,137,224	2,137,224
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	58,799	56,333	56,333
34.	A/C 552	5,489	5,270	5,270
35.	A/C 553	1,088,452	1,002,295	1,002,295
36.	A/C 554	96,352	93,557	93,557
37.	TRANSMISSION	3,301	3,191	3,191
38.	GENERAL PLANT	1,172,320	1,167,443	1,167,443
39.	TOTAL MAINTENANCE	$ 17,304,877	$ 15,916,343	$ 15,916,343

Arizona Electric Power Cooperative, Inc.

Projected Income Statement - Present and Proposed Rates

LINE NO.			-ACTUAL- TESTYEAR 12/31/2011		-ADJ. TEST YEAR- PRESENT RATES 12/31/2011		PROPOSED RATES 12/31/2011
	OTHER:						
40.	DEPRECIATION & AMORTIZATION	$	9,951,210	$	13,349,504	$	13,349,504
41.	ACC GROSS REVENUE TAXES		-		-		-
42.	TAXES		-		2,269,687		2,269,687
43.	TOTAL OTHER		9,951,210		15,619,191		15,619,191
44.	TOTAL OPERATING EXPENSES (b)		157,703,741		148,420,479		148,420,479
45.	ELECTRIC OPERATING MARGINS (b)		11,964,589		15,204,121		10,676,656
	INTEREST & OTHER DEDUCTIONS:						
46.	INTEREST ON LONG-TERM DEBT		10,518,102		9,281,871		9,281,871
47.	INTEREST CHARGES TO CONSTR		(27,664)		(27,664)		(27,664)
48.	OTHER INTEREST EXPENSE		448,729		448,729		448,729
49.	OTHER DEDUCTIONS		196,280		42,545		42,545
50.	TOTAL INTEREST & OTHER DEDUCTIONS (b)		11,135,447		9,745,481		9,745,481
51.	OPERATING MARGINS		829,142		5,458,640		931,175
	OTHER NON OPERATING INCOME:						
52.	INTEREST INCOME		438,715		438,715		438,715
53.	AFUDC		-		-		-
54.	OTHER NONOPERATING INCOME		587,331		587,331		587,331
55.	TOTAL OTHER NON OPERATING INCOME (b)		1,026,046		1,026,046		1,026,046
55a.	EXTRAORDINARY ITEMS (b)		-		-		-
56.	NET INCOME (MARGINS) (b)	$	1,855,188	$	6,484,686	$	1,957,221

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

RECAP SCHEDULES:
(b) A-2

Arizona Electric Power Cooperative, Inc.

Projected Changes in Financial Position
Present and Proposed Rates

SCHEDULE F-2
6/26/2012

LINE NO.		ACTUAL TESTYEAR ENDED 12/31/2011 (a)	PROJECTED YEAR PRESENT RATES ENDED 12/31/2011 (b)	PROJECTED YEAR PROPOSED RATES ENDED 12/31/2011 (b)
1.	NET CASH PROVIDED BY OPERATING ACTIVITIES	$ (13,940,473)	$ (9,994,975)	$ (14,522,440)
2.	NET CASH USED IN INVESTING ACTIVITIES	(19,295,572)	(19,295,572)	(19,295,572)
3.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	23,366,654	23,366,654	23,366,654
4.	NET DECREASE IN CASH AND CASH EQ.	$ (9,869,391)	$ (5,923,893)	$ (10,451,358)

SUPPORTING SCHEDULES:
(a) E-3

RECAP SCHEDULES:
(b) A-5

Arizona Electric Power Cooperative, Inc.

Projected Construction Requirements

SCHEDULE F-3
6/26/2012

LINE NO.		-ACTUAL- TESTYEAR ENDED 12/31/2011	-PROJECTED YEAR- YEAR ENDED 12/31/2012	YEAR ENDED 12/31/2013	YEAR ENDED 12/31/2014
1.	PRODUCTION PLANT	$ 17,065,274	$ 14,712,387	$ 6,036,496	$ 7,503,359
2.	TRANSMISSION PLANT	169,696	74,682	30,642	38,088
3.	GENERAL PLANT	(296,236)	149,364	61,284	76,176
4.	HEADQUARTERS BULDING	-	-	-	-
5.	RETIREMENTS	(66,356)	-	-	-
6.	TOTAL PLANT (a)	$ 16,872,378	$ 14,936,433	$ 6,128,422	$ 7,617,623

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) A-4

Arizona Electric Power Cooperative, Inc.

Assumptions Used in Developing Projections

SCHEDULE F-4
6/26/2012

LINE NO.		2012
1.	DSCR GOAL	1.32
2.	COAL	$2.60 $/MMBtu
3.	GAS	$4.87 $/MMBtu
4.	PURCHASED POWER:	
5.	CRSP	$5.18/KW + $.012490/KWH
6.	SOUTHPOINT (May - Oct)	$8.70/KW + $0.07592/KWH
7.	GRIFFITH	$6.30/KW + $0.08220/KWH
8.	PARKER DAVIS (Jan-Sept)	$1.86/KW + $0.00895/KWH
9.	PARKER DAVIS (Oct-Dec)	$1.86/KW + $0.00895/KWH
10.	ECONOMY	$0.02546/KWH
11.	FFB INTEREST RATE	4.9900%
12.	STAFFING LEVELS	261
13.	PROPERTY TAXES	$2,400,000
14.	DEPRECIATION RATES:	
15.	STEAM UNITS	
16.	ST 1	2.07%
17.	ST 2	2.28%
18.	ST 3	2.63%
19.	COMBUSTION TURBINES	
20.	GT 1	1.75%
21.	GT 2	1.75%
22.	GT 3	1.75%
23.	GT 4	1.75%
24.	HEADQUARTERS	2.00%
25.	GENERAL PLANT	6.00%
26.	VEHICLES	3-10 YEARS MINUS SALVAGE
27.	COMMUNICATIONS	6.00%
28.	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)		$154,924,873
3	NON-MEMBERS (b)		2,903,085
4	OTHER OPERATING REVENUE (b)		5,796,644
5	TOTAL REVENUES		$163,624,602
6	OPERATING EXPENSES (c)		148,420,479
7	ELECTRIC OPERATING MARGINS		$15,204,123
8	INCOME TAXES		0
9	RETURN (MARGINS) (LINE 7 - LINE 8)		$15,204,123
10			
11	RATE BASE (d)	$	267,463,587
12	RATE OF RETURN		5.68%
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)**	$150,397,406
3	**NON-MEMBERS (b)**	2,903,085
4	**OTHER OPERATING REVENUE (b)**	5,796,644
5	**TOTAL REVENUES**	$159,097,135
6	**OPERATING EXPENSES (c)**	148,420,479
7	**ELECTRIC OPERATING MARGINS**	$10,676,656
8	**INCOME TAXES**	0
9	**RETURN (MARGINS) (LINE 6 - LINE 7)**	$10,676,656
10		
11	**RATE BASE (d)**	$ 267,463,587
12	**RATE OF RETURN**	3.99%
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	TRICO ELECTRIC COOPERATIVE	COLLECTIVE ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1	REVENUE REQUIREMENT DEVELOPMENT					
2	FIXED COSTS					
3	BASE RESOURCES	$7,861,087	$6,960,795	$4,633,210	$2,503,251	$21,958,343
4	OTHER EXISTING RESOURCES	2,415,172	2,138,574	1,423,468	769,077	6,746,292
5	ADDITIONAL RESOURCES	0	0	2,869,257	94,851	2,964,108
6	SUB-TOTAL	$10,276,259	$9,099,369	$8,925,935	$3,367,179	$31,668,743
7						
8	O&M					
9	BASE RESOURCES	$16,124,106	$14,277,491	$9,503,314	$5,134,492	$45,039,403
10	OTHER EXISTING RESOURCES	904,604	801,004	533,160	288,058	2,526,826
11	ADDITIONAL RESOURCES	0	0	281,602	75,555	357,157
12	SUB-TOTAL	$17,028,710	$15,078,494	$10,318,076	$5,498,105	$47,923,385
13						
14	ENERGY					
15	BASE RESOURCES	$19,626,925	$21,122,159	$14,702,775	$6,766,382	$62,218,242
16	OTHER EXISTING RESOURCES	18,594	17,678	4,103,012	855,793	4,995,077
17	ADDITIONAL RESOURCES	0	0	3,395,252	196,707	3,591,959
18	SUB-TOTAL	$19,645,519	$21,139,838	$22,201,039	$7,818,882	$70,805,278
19						
20	TOTAL RESOURCE COSTS					
21	BASE RESOURCES	$43,612,118	$42,360,445	$28,839,299	$14,404,125	$129,215,987
22	OTHER EXISTING RESOURCES	3,338,370	2,957,257	6,059,639	1,912,928	14,268,194
23	ADDITIONAL RESOURCES	0	0	6,546,111	367,113	6,913,224
24	TOTAL	$46,950,488	$45,317,701	$41,445,050	$16,684,166	$150,397,406
25						
26						
27	RATE DEVELOPMENT					
28	BILLING DETERMINANTS					
29	BILLING DEMANDS	1,533,599	1,811,225	1,466,322	510,044	5,321,190
30	BASE RESOURCE KWH	678,088,000	718,868,000	498,876,619	231,625,173	2,127,457,792
31	OTHER EXISTING RESOURCES KWH	342,000	346,000	76,467,416	15,428,608	92,584,024
32	ADDITIONAL RESOURCES KWH	0	0	101,255,000	6,523,000	107,778,000
33	TOTAL KWH	678,430,000	719,214,000	676,599,035	253,576,781	2,327,819,816
34						
35	MONTHLY CHARGES					
36	FIXED CHARGE	$856,355	$758,281	$743,828	$280,598	$5.951
37	O&M CHARGE	$1,419,059	$1,256,541	$859,840	$458,175	$9.006
38	BASE ENERGY CHARGE	$0.02894	$0.02938	$0.02947	$0.02921	$0.02925
39	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.05437	$0.05109	$0.04219	$0.04795	$0.04286
40	ADDITIONAL RESOURCES CHARGE	$0.05437	$0.05109	$0.04219	$0.04795	$0.04286
41	AVERAGE ENERGY CHARGE	$0.028957	$0.029393	$0.032813	$0.030834	$0.030417

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	TRICO	CARM
1	OPERATING EXPENSES:					
2	OPERATIONS					
4	COAL COSTS FOR RESOURCE TRANSFERS	$750,138	$547,390	$115,112	$11,038	$76,598
5	COAL COSTS FOR THIRD PARTY SALES	1,791,954	915,690	423,016	212,142	241,106
6	RESOURCE TRANSFER CREDITS	(1,056,895)	(777,814)	(159,053)	(13,190)	(106,838)
7	SUB-TOTAL	$1,485,197	$685,266	$379,075	$209,990	$210,866
8						
9	BASE COST BEFORE ADJUSTMENTS	56,564,336	18,028,841	19,113,089	13,264,011	6,158,394
10						
11	PRODUCTION - FUEL A/C 501	$58,049,533	$18,714,107	$19,492,165	$13,474,002	$6,369,260
12						
13	ADJUSTMENTS					
14	PURCHASED POWER ACCOUNT 555 - ENERGY	7,016,000	2,236,221	2,370,706	1,645,212	763,861
15	TRANSMISSION OF ELEC BY OTHERS ACCOUNT 565 - ENERGY	553	176	187	130	60
16	FIRM CONTRACT REVENUES	0	0	0	0	0
17	BASE RESOURCE ECONOMY ENERGY	(2,847,844)	(1,323,579)	(740,898)	(416,568)	(366,799)
18	SCHEDULING REVENUES	0	0	0	0	0
19	OTHER OPERATING REVENUES	0	0	0	0	0
20	TOTAL NET BASE RESOURCES ENERGY REVENUE REQUIREMENTS	$62,218,242	$19,626,925	$21,122,159	$14,702,775	$6,766,382
21						
22						

LINE NO.	OTHER RESOURCE ENERGY COSTS AND CREDITS					
23						
24	DESCRIPTION	ENERGY	MEC	SSVEC	TRICO	CARM
25	OTHER EXISTING RESOURCE COSTS	$4,995,077	$18,594	$17,678	$4,103,012	$855,793
26	RESOURCE TRANSFER COSTS	1,056,895	1,546	4,988	933,482	116,878
27	OTHER RESOURCE COSTS	$3,938,182	$17,048	$12,690	$3,169,530	$738,915
28						
29	RESOURCE TRANSFER KWH	27,089,019	58,484	134,954	23,755,693	3,139,888
30	OTHER RESOURCE KWH	65,495,005	283,516	211,046	52,711,723	12,288,720
31	TOTAL OTHER EXISTING RESOURCE KWH	92,584,024	342,000	346,000	76,467,416	15,428,608

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 TRICO RESOURCES	ADDITIONAL CARM RESOURCES
1	OPERATING EXPENSES:					
2	OPERATIONS					
3	PRODUCTION - FUEL A/C 501	$ 58,823,108	$ 58,823,108	$ -	$ -	$ -
4	PRODUCTION - FUEL A/C 547	6,460,305	0	6,460,305	0	0
5	PRODUCTION - STEAM A/C 500	4,539,727	4,539,727	0	0	0
6	A/C 502	2,874,751	2,874,751	0	0	0
7	A/C 503	0	0	0	0	0
8	A/C 504	0	0	0	0	0
9	A/C 505	1,172,956	1,172,956	0	0	0
10	A/C 506 & 509	870,078	870,078	0	0	0
11	A/C 507	0	0	0	0	0
12	A/C 508	0	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	177,892	0	177,892	0	0
14	A/C 548	129,823	0	129,823	0	0
15	A/C 549	29,413	0	29,413	0	0
16	A/C 550	0	0	0	0	0
17	OTHER POWER SUPPLY	0	0	0	0	0
18	- DEMAND A/C 555	3,791,951	914,998	0	2,784,891	92,062
19	- ENERGY A/C 555	13,533,831	7,016,000	2,918,362	3,402,762	196,707
20	- INDIRECT A/C 555	0	0	0	0	0
21	A/C 556	3,509,469	3,299,808	143,603	62,060	3,998
22	A/C 557	75,351	72,209	3,142	0	0
23	TRANSMISSION					
24	A/C 562	0	0	0	0	0
25	A/C 564	0	0	0	0	0
26	A/C 565	12,379,664	11,646,044	506,820	219,542	7,258
27	ADMINISTRATIVE & GENERAL	8,516,626	8,020,315	438,825	0	57,486
28	TOTAL OPERATIONS	116,884,945	99,249,995	10,808,185	6,469,255	357,510
29						
30	PRODUCTION - STEAM - A/C 510	1,437,066	1,437,066	-	-	-
31	A/C 511	19,556	19,556	-	-	-
32	A/C 512	9,106,366	9,106,366	-	-	-
33	A/C 513	888,042	888,042	-	-	-
34	A/C 514	2,137,224	2,137,224	-	-	-
35	A/C 515.	-	-	-	-	-
36	PRODUCTION - OTHER - A/C 551	56,333	-	56,333	-	-
37	A/C 552	5,270	-	5,270	-	-
38	A/C 553	1,002,295	-	1,002,295	-	-
39	A/C 554.	93,557	-	93,557	-	-
40	TRANSMISSION					
41	A/C 570	3,191	3,058	133	-	-
42	GENERAL PLANT	1,167,443	1,100,421	60,209	-	6,814
43	TOTAL MAINTENANCE	15,916,343	14,691,732	1,217,797	-	6,814
44						
45	OTHER:					
46	DEPRECIATION & AMORTIZATION	13,349,504	11,944,097	1,405,407	-	-
47	TAXES	2,269,687	1,846,258	423,429	-	-
48	TOTAL OTHER	15,619,191	13,790,355	1,828,836	-	-
49						
50	TOTAL OPERATING EXPENSES	148,420,479	127,732,082	13,854,818	6,469,255	364,324
51						
52	INT. & OTHER DEDUCTIONS:					
53	INT. ON LONG-TERM DEBT	9,281,871	8,664,952	616,919	-	-
54	INT. CHARGES TO CONST.	(27,664)	(25,825)	(1,839)	-	-
55	OTHER INT. EXPENSE	448,729	418,904	29,825	-	-
56	OTHER DEDUCTIONS	42,545	39,717	2,828	-	-
57	TOTAL INT. & OTHER DED.	9,745,481	9,097,749	647,732	-	-
58						
59	TOTAL EXPENSES	$ 158,165,960	$ 136,829,830	$ 14,502,551	$ 6,469,255	$ 364,324
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 TRICO RESOURCES	ADDITIONAL CARM RESOURCES
1	OPERATING EXPENSES:					
2	OPERATIONS					
3	PRODUCTION - FUEL A/C 501	$71,296,090	$71,296,090	$0	$0	$0
4	PRODUCTION - FUEL A/C 547	6,501,235	0	6,501,235	0	0
5	PRODUCTION - STEAM A/C 500	4,706,859	4,706,859	0	0	0
6	A/C 502	4,381,006	4,381,006	0	0	0
7	A/C 503	0	0	0	0	0
8	A/C 504	0	0	0	0	0
9	A/C 505	1,645,798	1,645,798	0	0	0
10	A/C 506 & 509	884,983	884,983	0	0	0
11	A/C 507	0	0	0	0	0
12	A/C 508	0	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	184,413	0	184,413	0	0
14	A/C 548	551,193	0	551,193	0	0
15	A/C 549	29,906	0	29,906	0	0
16	A/C 550	0	0	0	0	0
17	OTHER POWER SUPPLY					
18	- DEMAND A/C 555	3,262,451	914,998	0	2,272,335	75,118
19	- ENERGY A/C 555	13,533,831	7,016,000	2,918,362	3,402,762	196,707
20	- INDIRECT A/C 555	0	0	0	0	0
21	A/C 556	3,246,651	3,059,612	133,150	50,628	3,262
22	A/C 557	75,351	72,209	3,142	0	0
23	TRANSMISSION					
24	A/C 562	0	0	0	0	0
25	A/C 564	0	0	0	0	0
26	A/C 565	9,249,224	8,646,155	376,269	219,542	7,258
27	ADMINISTRATIVE & GENERAL	10,898,663	10,273,119	562,085	0	63,459
28	TOTAL OPERATIONS	$130,447,654	$112,896,829	$11,259,755	$5,945,267	$345,803
29						
30	PRODUCTION - STEAM - A/C 510	1,500,521	$1,500,521	$0	$0	$0
31	A/C 511	40,104	40,104	0	0	0
32	A/C 512	9,749,499	9,749,499	0	0	0
33	A/C 513	1,380,730	1,380,730	0	0	0
34	A/C 514	2,209,310	2,209,310	0	0	0
35	A/C 515.	0	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	58,799	0	58,799	0	0
37	A/C 552	5,489	0	5,489	0	0
38	A/C 553	1,088,452	0	1,088,452	0	0
39	A/C 554.	96,352	0	96,352	0	0
40	TRANSMISSION					
41	A/C 570	3,301	3,163	138	0	0
42	GENERAL PLANT	1,172,320	1,105,033	60,461	0	6,826
43	TOTAL MAINTENANCE	$17,304,877	$15,988,360	$1,309,691	$0	$6,826
44						
45	OTHER:					
46	DEPRECIATION & AMORTIZATION	$9,951,210	$8,229,376	$1,721,834	$0	$0
47	TAXES	0	0	0	0	0
48	TOTAL OTHER	$9,951,210	$8,229,376	$1,721,834	$0	$0
49						
50	TOTAL OPERATING EXPENSES	$157,703,741	$137,114,565	$14,291,280	$5,945,267	$352,629
51						
52	INT. & OTHER DEDUCTIONS:					
53	INT. ON LONG-TERM DEBT	$10,518,102	$9,819,018	$699,084	$0	$0
54	INT. CHARGES TO CONST.	(27,664)	(25,825)	(1,839)	-	-
55	OTHER INT. EXPENSE	448,729	418,904	29,825	0	0
56	OTHER DEDUCTIONS	196,280	183,234	13,046	0	0
57	TOTAL INT. & OTHER DED.	$11,135,447	$10,395,331	$740,116	$0	$0
58						
59	TOTAL EXPENSES	$ 168,839,188	$ 147,509,896	$ 15,031,396	$ 5,945,267	$ 352,629
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 TRICO RESOURCES	ADDITIONAL CARM RESOURCES
1	OPERATING EXPENSES:					
2	OPERATIONS					
3	PRODUCTION - FUEL A/C 501	$ (12,159,284)	$ (12,159,284)	$ -	$ -	$ -
4	PRODUCTION - FUEL A/C 547	(40,930)	-	(40,930)	-	-
5	PRODUCTION - STEAM A/C 500	(167,132)	(167,132)	-	-	-
6	A/C 502	(92,646)	(92,646)	-	-	-
7	A/C 503	-	-	-	-	-
8	A/C 504	-	-	-	-	-
9	A/C 505	(52,277)	(52,277)	-	-	-
10	A/C 506 & 509	(14,905)	(14,905)	-		-
11	A/C 507	-	-	-	-	-
12	A/C 508	-	-	-	-	-
13	PRODUCTION - OTHER - A/C 546	(6,521)	-	(6,521)	-	-
14	A/C 548	(712)	-	(712)	-	-
15	A/C 549	(493)	-	(493)	-	-
16	A/C 550	-	-	-	-	-
17	OTHER POWER SUPPLY					
18	- DEMAND A/C 555	529,500	-	-	512,556	16,944
19	- ENERGY A/C 555	-	-	-	-	-
20	- INDIRECT A/C 555	-	-	-	-	-
21	A/C 556	387,676	354,308	15,419	16,863	1,086
22	A/C 557	-	-	-	-	-
23	TRANSMISSION					
24	A/C 562	-	-	-	-	-
25	A/C 564	-	-	-	-	-
26	A/C 565	5,856,312	5,612,082	244,230	-	-
27	ADMINISTRATIVE & GENERAL	(2,391,719)	(2,261,930)	(123,760)	-	(6,030)
28	TOTAL OPERATIONS	(8,153,131)	(8,781,784)	87,233	529,419	12,001
29						
30	PRODUCTION - STEAM - A/C 510	(63,455)	(63,455)	-	-	-
31	A/C 511	(20,548)	(20,548)	-	-	-
32	A/C 512	(643,133)	(643,133)	-	-	-
33	A/C 513	(492,688)	(492,688)	-	-	-
34	A/C 514	(72,086)	(72,086)	-	-	-
35	A/C 515.	-	-	-	-	-
36	PRODUCTION - OTHER - A/C 551	(2,466)	-	(2,466)		-
37	A/C 552	(219)	-	(219)		-
38	A/C 553	(86,157)	-	(86,157)		-
39	A/C 554.	(2,795)	-	(2,795)		-
40	TRANSMISSION					
41	A/C 570	(110)	(105)	(5)	-	-
42	GENERAL PLANT	(4,877)	(4,612)	(252)	-	(12)
43	TOTAL MAINTENANCE	(1,388,534)	(1,296,628)	(91,894)		(12)
44						
45	OTHER:					
46	DEPRECIATION & AMORTIZATION	3,398,294	3,714,721	(316,427)	-	-
47	TAXES	-	-	-	-	-
48	TOTAL OTHER	3,398,294	3,714,721	(316,427)	-	-
49						
50	TOTAL OPERATING EXPENSES	(6,143,371)	(6,363,691)	(321,087)	529,419	11,988
51						
52	INT. & OTHER DEDUCTIONS:					
53	INT. ON LONG-TERM DEBT	(1,236,231)	(1,154,065)	(82,166)	-	-
54	INT. CHARGES TO CONST.	-	-	-	-	-
55	OTHER INT. EXPENSE	-	-	-	-	-
56	OTHER DEDUCTIONS	(153,735)	(143,517)	(10,218)	-	-
57	TOTAL INT. & OTHER DED.	(1,389,966)	(1,297,582)	(92,384)	-	-
58						
59	TOTAL EXPENSES	$ (7,533,337)	$ (7,661,273)	$ (413,471)	$ 529,419	$ 11,988
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 TRICO RESOURCES	ADDITIONAL CARM RESOURCES
1	OPERATING EXPENSES:					
2	OPERATIONS					
3	PRODUCTION - FUEL A/C 501	$ (313,698)	$ (313,698)	$ -	$ -	$ -
4	PRODUCTION - FUEL A/C 547	-	-	-	-	-
5	PRODUCTION - STEAM A/C 500	-	-	-	-	-
6	A/C 502	(1,413,609)	(1,413,609)	-	-	-
7	A/C 503	-	-	-	-	-
8	A/C 504	-	-	-	-	-
9	A/C 505	(420,565)	(420,565)	-	-	-
10	A/C 506 & 509	-	-	-	-	-
11	A/C 507	-	-	-	-	-
12	A/C 508	-	-	-	-	-
13	PRODUCTION - OTHER - A/C 546	-	-	-	-	-
14	A/C 548	(420,658)	-	(420,658)	-	-
15	A/C 549	-	-	-	-	-
16	A/C 550	-	-	-	-	-
17	OTHER POWER SUPPLY					
18	- DEMAND A/C 555	-	-			
19	- ENERGY A/C 555	-	-	-	-	-
20	- INDIRECT A/C 555	-	-	-	-	-
21	A/C 556	(124,858)	(114,111)	(4,966)	(5,431)	(350)
22	A/C 557	-	-	-	-	-
23	TRANSMISSION					
24	A/C 562	-	-	-	-	-
25	A/C 564	-	-	-	-	-
26	A/C 565	(2,725,872)	(2,612,193)	(113,679)	-	-
27	ADMINISTRATIVE & GENERAL	9,682	9,126	499	-	56
28	TOTAL OPERATIONS	(5,409,578)	(4,865,050)	(538,804)	(5,431)	(294)
29						
30	PRODUCTION - STEAM - A/C 510	-	-	-	-	-
31	A/C 511	-	-	-	-	-
32	A/C 512	-	-	-	-	-
33	A/C 513	-	-	-	-	-
34	A/C 514	-	-	-	-	-
35	A/C 515.	-	-	-	-	-
36	PRODUCTION - OTHER - A/C 551	-	-	-	-	-
37	A/C 552	-	-	-	-	-
38	A/C 553	-	-	-	-	-
39	A/C 554.	-	-	-	-	-
40	TRANSMISSION					
41	A/C 570	-	-	-	-	-
42	GENERAL PLANT	-	-	-	-	-
43	TOTAL MAINTENANCE	-	-	-		-
44						
45	OTHER:					
46	DEPRECIATION & AMORTIZATION	-	-	-	-	-
47	TAXES	2,269,687	1,846,258	423,429	-	-
48	TOTAL OTHER	2,269,687	1,846,258	423,429	-	-
49						
50	TOTAL OPERATING EXPENSES	(3,139,891)	(3,018,792)	(115,374)	(5,431)	(294)
51						
52	INT. & OTHER DEDUCTIONS:					
53	INT. ON LONG-TERM DEBT	-	-	-	-	-
54	INT. CHARGES TO CONST.	-	-	-	-	-
55	OTHER INT. EXPENSE	-	-	-	-	-
56	OTHER DEDUCTIONS	-	-	-	-	-
57	TOTAL INT. & OTHER DED.	-	-	-	-	-
58						
59	TOTAL EXPENSES	$ (3,139,891)	$ (3,018,792)	$ (115,374)	$ (5,431)	$ (294)
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 FIXED	BASE RESOURCES O&M	BASE RESOURCES ENERGY	OTHER EXISTING RESOURCES FIXED	OTHER EXISTING RESOURCES O&M	OTHER EXISTING RESOURCES ENERGY	ADDITIONAL TRICO RESOURCES FIXED	ADDITIONAL TRICO RESOURCES O&M	ADDITIONAL TRICO RESOURCES ENERGY	ADDITIONAL CARM RESOURCES FIXED	ADDITIONAL CARM RESOURCES O&M	ADDITIONAL CARM RESOURCES ENERGY	TOTAL AEPCO REVENUE REQUIREMENT FIXED	TOTAL AEPCO REVENUE REQUIREMENT O&M	TOTAL AEPCO REVENUE REQUIREMENT ENERGY	Total
1	OPERATING EXPENSES:																
2	OPERATIONS																
3	PRODUCTION - FUEL A/C 501	$773,575	$0	$58,049,533	$0	$0	$0	$0	$0	$0	$0	$0	$0	$773,575	$0	$58,049,533	$58,823,108
4	PRODUCTION - FUEL A/C 547	0	0	0	4,383,590	0	2,076,715	0	0	0	0	0	0	4,383,590	0	2,076,715	6,460,305
5	PRODUCTION - STEAM A/C 500	0	4,539,727	0	0	0	0	0	0	0	0	0	0	0	4,539,727	0	4,539,727
6	A/C 502	0	2,874,751	0	0	0	0	0	0	0	0	0	0	0	2,874,751	0	2,874,751
7	A/C 503	0	0	0	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	0	0	0
9	A/C 505	0	1,172,956	0	0	0	0	0	0	0	0	0	0	0	1,172,956	0	1,172,956
10	A/C 506 & 509	0	870,078	0	0	0	0	0	0	0	0	0	0	0	870,078	0	870,078
11	A/C 507	0	0	0	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	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0	177,892	0	0	0	0	0	0	0	0	177,892	0	177,892
14	A/C 548	0	0	0	0	129,823	0	0	0	0	0	0	0	0	129,823	0	129,823
15	A/C 549	0	0	0	0	29,413	0	0	0	0	0	0	0	0	29,413	0	29,413
16	A/C 550	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	OTHER POWER SUPPLY													0	0	0	
18	- DEMAND A/C 555	914,998	0	0	0	0	0	2,784,891	0	0	92,062	0	0	3,791,951	0	0	3,791,951
19	- ENERGY A/C 555	0	0	7,016,000	0	0	2,918,362	0	0	3,402,762	0	0	196,707	0	0	13,533,831	13,533,831
20	- INDIRECT A/C 555	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	A/C 556	0	3,299,808	0	0	143,603	0	0	62,060	0	0	3,998	0	0	3,509,469	0	3,509,469
22	A/C 557	0	72,209	0	0	3,142	0	0	0	0	0	0	0	0	75,351	0	75,351
23	TRANSMISSION																
24	A/C 562	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	A/C 564	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	A/C 565	0	11,645,491	553	0	506,820	0	0	219,542	0	0	7,258	0	0	12,379,111	553	12,379,664
27	ADMINISTRATIVE & GENERAL	0	8,020,315	0		438,825	0	0	0	0	0	57,486	0	0	8,516,626	0	8,516,626
28	TOTAL OPERATIONS	$1,688,573	$32,495,336	$65,066,086	$4,383,590	$1,429,518	$4,995,077	$2,784,891	$281,602	$3,402,762	$92,062	$68,741	$196,707	$8,949,116	$34,275,197	$73,660,632	$116,884,945
29																	
30	PRODUCTION - STEAM - A/C 510	0	1,437,066	0	0	0	0	0	0	0	0	0	0	0	1,437,066	0	1,437,066
31	A/C 511	0	19,556	0	0	0	0	0	0	0	0	0	0	0	19,556	0	19,556
32	A/C 512	0	9,106,366	0	0	0	0	0	0	0	0	0	0	0	9,106,366	0	9,106,366
33	A/C 513	0	888,042	0	0	0	0	0	0	0	0	0	0	0	888,042	0	888,042
34	A/C 514	0	2,137,224	0	0	0	0	0	0	0	0	0	0	0	2,137,224	0	2,137,224
35	A/C 515.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0	56,333	0	0	0	0	0	0	0	0	56,333	0	56,333
37	A/C 552	0	0	0	0	5,270	0	0	0	0	0	0	0	0	5,270	0	5,270
38	A/C 553	0	0	0	0	1,002,295	0	0	0	0	0	0	0	0	1,002,295	0	1,002,295
39	A/C 554.	0	0	0	0	93,557	0	0	0	0	0	0	0	0	93,557	0	93,557
40	TRANSMISSION																
41	A/C 570	0	3,058	0	0	133	0	0	0	0	0	0	0	0	3,191	0	3,191
42	GENERAL PLANT	0	1,100,421	0	0	60,209	0	0	0	0	0	6,814	0	0	1,167,443	0	1,167,443
43	TOTAL MAINTENANCE	$0	$14,691,732	$0	$0	$1,217,797	$0	$0	$0	$0	$0	$6,814	$0	$0	$15,916,343	$0	$15,916,343
44																	
45	OTHER:																
46	DEPRECIATION & AMORTIZATION	$11,944,097	$0	$0	$1,405,407	$0	$0	$0	$0	$0	$0	$0	$0	13,349,504	0	0	13,349,504
47	TAXES	1,846,258	0	0	423,429	0	0	0	0	0	0	0	0	2,269,687	0	0	2,269,687
48	TOTAL OTHER	$13,790,355	$0	$0	$1,828,836	$0	$0	$0	$0	$0	$0	$0	$0	$15,619,191	$0	$0	$15,619,191
49																	
50	TOTAL OPERATING EXPENSES	$15,478,928	$47,187,068	$65,066,086	$6,212,426	$2,647,315	$4,995,077	$2,784,891	$281,602	$3,402,762	$92,062	$75,555	$196,707	$24,568,307	$50,191,540	$73,660,632	$148,420,479
51																	
52	INT. & OTHER DEDUCTIONS:																
53	INT. ON LONG-TERM DEBT	$8,664,952	$0	$0	$616,919	$0	$0	$0	$0	$0	$0	$0	$0	9,281,871	0	0	$9,281,871
54	INT. CHARGES TO CONST.	(25,825)	-	-	(1,839)	-	-	-	-	-	-	-	-	(27,664)	-	-	(27,664)
55	OTHER INT. EXPENSE	418,904	0	0	29,825	0	0	0	0	0	0	0	0	448,729	0	0	448,729
56	OTHER DEDUCTIONS	39,717	0	0	2,828	0	0	0	0	0	0	0	0	42,545	0	0	42,545
57	TOTAL INT. & OTHER DED.	$9,097,749	$0	$0	$647,732	$0	$0	$0	$0	$0	$0	$0	$0	$9,745,481	$0	$0	$9,745,481
58																	
59	TOTAL EXPENSES	$24,576,676	$47,187,068	$65,066,086	$6,860,159	$2,647,315	$4,995,077	$2,784,891	$281,602	$3,402,762	$92,062	$75,555	$196,707	$34,313,788	$50,191,540	$73,660,632	$158,165,960
60																	
61	REVENUE CREDITS																
62	FIRM CONTRACT REVENUES	$47,731	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	47,731	0	0	$47,731
63	ECONOMY ENERGY	0	0	2,847,844	0	0	0	0	0	7,510	0	0	0	0	0	2,855,354	2,855,354
64	SCHEDULING REVENUES	2,097,678	0	0	0	0	0	0	0	0	0	0	0	2,097,678	0	0	2,097,678
65	OTHER OPERATING REVENUES	1,118,579	2,147,665	0	312,232	120,490	0	0	0	0	0	0	0	1,430,811	2,268,155	0	3,698,966
66	TOTAL REVENUE CREDITS	$3,263,988	$2,147,665	$2,847,844	$312,232	$120,490	$0	$0	$0	$7,510	$0	$0	$0	$3,576,220	$2,268,155	$2,855,354	$8,699,729
67																	
68	MARGINS	645,654	0	0	198,365	0	0	84,366	0	0	2,789	0	0	931,175	0	0	931,175
69																	
70	CLASS A MEMBER REVENUE REQUIREMENTS	$ 21,958,343	$ 45,039,403	$ 62,218,242	$ 6,746,292	$ 2,526,826	$ 4,995,077	$ 2,869,257	$ 281,602	$ 3,395,252	$ 94,851	$75,555	$ 196,707	$ 31,668,743	$ 47,923,385	$ 70,805,278	$ 150,397,406

Arizona Electric Power Cooperative, Inc.
DERIVATION OF ALLOCATION FACTORS

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	TRICO ELECTRIC COOPERATIVE	COLLECTIVE ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1	ALLOCATION FACTORS					
2	ENERGY ALLOCATION FACTORS					
3	BASE RESOURCE KWH	678,088,000	718,868,000	498,876,619	231,625,173	2,127,457,792
4	OTHER EXISTING RESOURCES KWH	342,000	346,000	76,467,416	15,428,608	92,584,024
5	ADDITIONAL RESOURCES KWH	0	0	101,255,000	6,523,000	107,778,000
6						
7	BASE RESOURCE KWH	31.873%	33.790%	23.449%	10.887%	100.000%
8	OTHER EXISTING RESOURCES KWH	0.369%	0.374%	82.592%	16.664%	100.000%
9	ADDITIONAL ARM RESOURCES KWH	0.000%	0.000%	93.948%	6.052%	100.000%
10						
11	FIXED COST ALLOCATION FACTORS					
12	ACP	35.800%	31.700%	21.100%	11.400%	100.000%
13	ACP OF SOUTHPARK AND GRIFFITH	0.000%	0.000%	96.800%	3.200%	100.000%
14						
15	FUNCTIONALIZATION FACTORS	BASE RESOURCES	OTHER EXISTING RESOURCES	ADDITIONAL TRICO RESOURCES	ADDITIONAL CARM RESOURCES	TOTAL AEPC
16	DISPATCHED ENERGY (KWH)	2,127,457,792	92,584,024	101,255,000	6,523,000	2,327,819,816
17	DISPATCHED ENERGY (%)	91.393%	3.977%	4.350%	0.280%	100.000%
18						
19	SUB-TOTAL PURCHASED POWER					
20	PRODUCTION - FUEL A/C 501	$ 71,296,090	$ -	$ -	$ -	$ 71,296,090
21	PRODUCTION - FUEL A/C 547	-	6,501,235	-	-	6,501,235
22	SUBTOTAL ($)	$ 71,296,090	$ 6,501,235	$ -	$ -	$ 77,797,325
23	SUBTOTAL (%)	91.643%	8.357%	0.000%	0.000%	100.000%
24						
25	PAYROLL EXCLUDING A&G AND GEN PLT MNTC ($)	$11,113,323	$612,631	$9,333	$601	$11,735,887
26	PAYROLL EXCLUDING A&G AND GEN PLT MNTC (%)	94.695%	5.220%	0.080%	0.005%	100.000%
27						
28	INTEREST ON LONG TERM DEBT ($)	$9,819,018	$699,084	$0	$0	$10,518,102
29	INTEREST ON LONG TERM DEBT (%)	93.354%	6.646%	0.000%	0.000%	100.000%
30						
31	TOTAL EXPENSES LESS A&G ($)	$128,809,515	$14,063,726	$6,469,255	$306,838	$149,649,334
32	TOTAL EXPENSES LESS A&G (%)	86.074%	9.398%	4.323%	0.205%	100.000%
33						
34	A&G EXPENSES ($)	$10,273,119	$562,085	$0	$63,459	$10,898,663
35	A&G EXPENSES (%)	94.260%	5.157%	0.000%	0.582%	100.000%

Arizona Electric Power Cooperative, Inc.
DERIVATION OF FUEL BASE CHARGES

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	TRICO ELECTRIC COOPERATIVE	COLLECTIVE ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1	**FUEL BASE CHARGES:**					
2	BASE RESOURCES BASE CHARGE					
3	BASE RESOURCES ENERGY COSTS	$19,626,925	$21,122,159	$14,702,775	$6,766,382	$62,218,242
4	BASE RESOURCE KWH	678,088,000	718,868,000	498,876,619	231,625,173	2,127,457,792
5	BASE RESOURCES BASE CHARGE - $/kWh	$0.02894	$0.02938	$0.02947	$0.02921	$0.02925
6						
7	OTHER RESOURCES BASE CHARGE					
8	OTHER RESOURCES ENERGY COSTS	$18,594	$17,678	$7,498,264	$1,052,500	$8,587,036
9	OTHER RESOURCES KWH	342,000	346,000	177,722,416	21,951,608	200,362,024
10	OTHER REOURCES BASE CHARGE - $/kWh	$0.05437	$0.05109	$0.04219	$0.04795	$0.04286
11						
12	FIXED FUEL BASE CHARGES					
13	FIXED COSTS:					
14	FIXED COAL COSTS	$276,940	$245,223	$163,224	$88,188	$773,575
15	FIXED GAS COSTS	1,569,325	1,389,598	924,937	499,729	4,383,590
16	PURCHASED DEMAND COSTS:					
17	BASE RESOURCES	327,569	290,054	193,065	104,310	914,998
18	OTHER RESOURCES	0	0	0	0	0
19	ADDITIONAL RESOURCES	0	0	2,784,891	92,062	2,876,953
20	TOTAL PURCHASED DEMAND COSTS	327,569	290,054	2,977,956	196,372	3,791,951
21	TRANSMISSION OF ELECTRICITY BY OTHERS:					
22	BASE RESOURCES WHEELING	4,169,086	3,691,621	2,457,199	1,327,586	11,645,491
23	OTHER RESOURCES WHEELING	181,441	160,662	106,939	57,777	506,820
24	ADDITIONAL RESOURCES WHEELING	0	0	219,542	7,258	226,800
25	TOTAL WHEELING COSTS	4,350,527	3,852,283	2,783,680	1,392,621	12,379,111
26	SUBTOTAL	6,524,362	5,777,158	6,849,797	2,176,910	21,328,227
27	FIRM CONTRACT REVENUES	17,088	15,131	10,071	5,441	47,731
28	TOTAL FIXED FUEL BASE COSTS	$6,507,274	$5,762,028	$6,839,726	$2,171,468	$21,280,496
29	FIXED FUEL BASE CHARGES - PER MONTH	$542,273	$480,169	$569,977	$180,956	$1,773,375

SUPPORTING SCHEDULES:
(a) G-6, PAGE 5

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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	$154,924,873	$150,397,406	($4,527,467)	-2.92%
2	Non-Members	2,903,085	2,903,085	0	0.00%
3	Other Operating Revenues	5,796,644	5,796,644	0	0.00%
4	Total AEPCO	$163,624,602	$159,097,135	($4,527,467)	-2.77%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.
Analysis of Revenue by Detailed Class
December 31, 20011 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	51,247,082	89,412	$3,330,240	$3,276,672	($53,567)	-1.61%
3	Duncan	1	29,616,232	61,986	2,015,759	1,992,563	(23,196)	-1.15%
4	Graham	1	172,713,467	358,646	11,557,588	11,414,931	(142,657)	-1.23%
5	Mohave	1	678,430,000	1,533,599	50,184,760	46,950,488	(3,234,272)	-6.44%
6	Sulphur	1	719,214,000	1,811,225	47,411,111	45,317,701	(2,093,409)	-4.42%
7	Trico	1	676,599,035	1,466,322	40,425,415	41,445,050	1,019,635	2.52%
8	Total Class A Members	6	2,327,819,816	5,321,190	$154,924,873	$150,397,406	($4,527,467)	-2.92%
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	0	0	0	0	0	N/A	N/A
15	Total Firm Contracts	0	0	0	$0	$0	N/A	N/A
16								
17	Total AEPCO	6	2,327,819,816	5,321,190	$154,924,873	$150,397,406	($4,527,467)	-2.92%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER BOOKED SALES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1														
2	ANZA													
3	MW	6.744	7.368	5.988	5.424	5.760	8.436	10.524	9.396	8.400	6.804	7.164	7.404	89.412
4	MWH	4,257.329	4,142.808	4,173.822	3,770.215	3,927.846	4,098.396	4,852.867	5,136.535	4,269.366	3,812.046	4,034.970	4,770.882	51,247.082
5														
6	DUNCAN													
7	MW	4.304	5.306	3.854	3.808	5.380	7.406	6.954	6.748	6.084	4.422	3.588	4.132	61.986
8	MWH	2,283.326	2,048.024	2,011.360	2,160.532	2,387.618	3,278.746	3,616.574	3,308.787	2,462.224	1,863.676	1,835.082	2,360.283	29,616.232
9														
10	GRAHAM													
11	MW	22.019	24.442	24.082	24.682	30.252	44.283	40.089	40.545	39.290	25.523	20.126	23.313	358.646
12	MWH	11,984.085	10,179.691	12,037.507	13,307.005	13,805.610	19,434.851	21,429.924	20,180.101	15,077.946	11,386.313	10,850.200	13,040.234	172,713.467
13														
14	MOHAVE													
15	MW	87.362	96.045	81.470	101.945	127.494	175.484	187.399	197.842	179.554	134.569	77.596	86.839	1,533.599
16	MWH	54,728.000	45,968.000	38,932.000	38,255.000	53,012.000	67,971.000	80,958.000	83,569.000	66,876.000	53,714.000	40,895.000	53,552.000	678,430.000
17														
18	SULPHUR													
19	MW	119.327	151.864	111.504	125.854	155.264	202.467	202.194	204.733	190.763	120.205	102.894	124.156	1,811.225
20	MWH	62,152.000	55,094.000	42,355.000	35,372.000	60,460.000	71,518.000	73,729.000	76,858.000	66,969.000	58,272.000	50,347.000	66,088.000	719,214.000
21														
22	TRICO													
23	MW	93.162	109.942	78.252	93.298	117.654	173.678	170.512	169.634	162.034	124.318	77.608	96.230	1,466.322
24	MWH	49,056.197	44,022.811	42,924.616	45,454.856	51,780.343	71,393.709	77,854.329	81,298.148	65,194.146	51,719.720	42,828.323	53,071.837	676,599.035
25														
26														
27														
28	FULL REQUIREMENTS													
29	MW	33.067	37.116	33.924	33.914	41.392	60.125	57.567	56.689	53.774	36.749	30.878	34.849	510.044
30	MWH	18,524.740	16,370.523	18,222.689	19,237.752	20,121.074	26,811.993	29,899.365	28,625.423	21,809.536	17,062.035	16,720.252	20,171.399	253,576.781
31														
32	PARTIAL REQUIREMENTS													
33	MW	299.851	357.851	271.226	321.097	400.412	551.629	560.105	572.209	532.351	379.092	258.098	307.225	4,811.146
34	MWH	165,936.197	145,084.811	124,211.616	119,081.856	165,252.343	210,882.709	232,541.329	241,725.148	199,039.146	163,705.720	134,070.323	172,711.837	2,074,243.035
35														
36														
37														
38	TOTAL CLASS A													
39	MW	332.918	394.967	305.150	355.011	441.804	611.754	617.672	628.898	586.125	415.841	288.976	342.074	5,321.190
40	MWH	184,460.937	161,455.334	142,434.305	138,319.608	185,373.417	237,694.702	262,440.694	270,350.571	220,848.682	180,767.755	150,790.575	192,883.236	2,327,819.816

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

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	ANZA													
2	MW	6.744	7.368	5.988	5.424	5.760	8.436	10.524	9.396	8.400	6.804	7.164	7.404	89.412
3	MWH	4,257.329	4,142.808	4,173.822	3,770.215	3,927.846	4,098.396	4,852.867	5,136.535	4,269.366	3,812.046	4,034.970	4,770.882	51,247.082
4														
5	DUNCAN													
6	MW	4.304	5.306	3.854	3.808	5.380	7.406	6.954	6.748	6.084	4.422	3.588	4.132	61.986
7	MWH	2,283.326	2,048.024	2,011.360	2,160.532	2,387.618	3,278.746	3,616.574	3,308.787	2,462.224	1,863.676	1,835.082	2,360.283	29,616.232
8														
9	GRAHAM													
10	MW	22.019	24.442	24.082	24.682	30.252	44.283	40.089	40.545	39.290	25.523	20.126	23.313	358.646
11	MWH	11,984.085	10,179.691	12,037.507	13,307.005	13,805.610	19,434.851	21,429.924	20,180.101	15,077.946	11,386.313	10,850.200	13,040.234	172,713.467
12														
13	MOHAVE													
14	MW	87.362	96.045	81.470	101.945	127.494	175.484	187.399	197.842	179.554	134.569	77.596	86.839	1,533.599
15	CHEMSTAR O&M 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
16	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
17	SCHED B O&M 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
18	ADJ MW	87.362	96.045	81.470	101.945	127.494	175.484	187.399	197.842	179.554	134.569	77.596	86.839	1,533.599
19	ENERGY MIN 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
20	ADJUSTED MWH	54,728.000	45,968.000	38,932.000	38,255.000	53,012.000	67,971.000	80,958.000	83,569.000	66,876.000	53,714.000	40,895.000	53,552.000	678,430.000
21														
22	SULPHUR													
23	MW	119.327	151.864	111.504	125.854	155.264	202.467	202.194	204.733	190.763	120.205	102.894	124.156	1,811.225
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	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
26	ADJ MW	119.327	151.864	111.504	125.854	155.264	202.467	202.194	204.733	190.763	120.205	102.894	124.156	1,811.225
27	ENERGY MIN 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
28	ADJUSTED MWH	62,152.000	55,094.000	42,355.000	35,372.000	60,460.000	71,518.000	73,729.000	76,858.000	66,969.000	58,272.000	50,347.000	66,088.000	719,214.000
29														
30	TRICO													
31	MW	93.162	109.942	78.252	93.298	117.654	173.678	170.512	169.634	162.034	124.318	77.608	96.230	1,466.322
32	MWH	49,056.197	44,022.811	42,924.616	45,454.856	51,780.343	71,393.709	77,854.329	81,298.148	65,194.146	51,719.720	42,828.323	53,071.837	676,599.035
33														
34														
35														
36	FULL REQUIREMENTS													
37	MW	33.067	37.116	33.924	33.914	41.392	60.125	57.567	56.689	53.774	36.749	30.878	34.849	510.044
38	MWH	18,524.740	16,370.523	18,222.689	19,237.752	20,121.074	26,811.993	29,899.365	28,625.423	21,809.536	17,062.035	16,720.252	20,171.399	253,576.781
39														
40	PARTIAL REQUIREMENTS													
41	MW	299.851	357.851	271.226	321.097	400.412	551.629	560.105	572.209	532.351	379.092	258.098	307.225	4,811.146
42	MWH	165,936.197	145,084.811	124,211.616	119,081.856	165,252.343	210,882.709	232,541.329	241,725.148	199,039.146	163,705.720	134,070.323	172,711.837	2,074,243.035
43														
44														
45														
46	TOTAL CLASS A													
47	MW	332.918	394.967	305.150	355.011	441.804	611.754	617.672	628.898	586.125	415.841	288.976	342.074	5,321.190
48	MWH	184,460.937	161,455.334	142,434.305	138,319.608	185,373.417	237,694.702	262,440.694	270,350.571	220,848.682	180,767.755	150,790.575	192,883.236	2,327,819.816

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED BILLING DETERMINANTS

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	ANZA													
2	KW	6,744	7,368	5,988	5,424	5,760	8,436	10,524	9,396	8,400	6,804	7,164	7,404	89,412
3	KWH - TOTAL	4,257,329	4,142,808	4,173,822	3,770,215	3,927,846	4,098,396	4,852,867	5,136,535	4,269,366	3,812,046	4,034,970	4,770,882	51,247,082
4	KWH - BASE RESOURCES	4,197,622	4,067,797	3,173,855	2,633,137	3,584,926	3,742,609	4,395,121	4,686,541	4,162,288	3,755,926	3,795,186	4,765,323	46,960,331
5	KWH - OTHER EXISTING RESOURCES	59,707	75,011	999,967	1,137,078	342,920	355,787	457,746	449,994	107,078	56,120	239,784	5,559	4,286,751
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
7														
8	DUNCAN													
9	KW	4,304	5,306	3,854	3,808	5,380	7,406	6,954	6,748	6,084	4,422	3,588	4,132	61,986
10	KWH - TOTAL	2,283,326	2,048,024	2,011,360	2,160,532	2,387,618	3,278,746	3,616,574	3,308,787	2,462,224	1,863,676	1,835,082	2,360,283	29,616,232
11	KWH - BASE RESOURCES	2,251,302	2,010,942	1,529,477	1,508,927	2,179,167	2,994,114	3,275,441	3,018,916	2,400,470	1,836,239	1,726,029	2,357,533	27,088,557
12	KWH - OTHER EXISTING RESOURCES	32,024	37,082	481,883	651,605	208,451	284,632	341,133	289,871	61,754	27,437	109,053	2,750	2,527,675
13	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
14														
15	GRAHAM													
16	KW	22,019	24,442	24,082	24,682	30,252	44,283	40,089	40,545	39,290	25,523	20,126	23,313	358,646
17	KWH - TOTAL	11,984,085	10,179,691	12,037,507	13,307,005	13,805,610	19,434,851	21,429,924	20,180,101	15,077,946	11,386,313	10,850,200	13,040,234	172,713,467
18	KWH - BASE RESOURCES	11,816,010	9,995,374	9,153,553	9,293,680	12,600,313	17,747,686	19,408,552	18,412,194	14,699,784	11,218,688	10,205,411	13,025,040	157,576,285
19	KWH - OTHER EXISTING RESOURCES	168,075	184,317	2,883,954	4,013,325	1,205,297	1,687,165	2,021,372	1,767,907	378,162	167,625	644,789	15,194	15,137,182
20	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
21														
22	MOHAVE													
23	KW	87,362	96,045	81,470	101,945	127,494	175,484	187,399	197,842	179,554	134,569	77,596	86,839	1,533,599
24	KWH - TOTAL	54,728,000	45,968,000	38,932,000	38,255,000	53,012,000	67,971,000	80,958,000	83,569,000	66,876,000	53,714,000	40,895,000	53,552,000	678,430,000
25	KWH - BASE RESOURCES	54,728,000	45,960,000	38,687,000	38,254,000	53,012,000	67,970,000	80,900,000	83,541,000	66,876,000	53,714,000	40,894,000	53,552,000	678,088,000
26	KWH - OTHER EXISTING RESOURCES	0	8,000	245,000	1,000	0	1,000	58,000	28,000	0	0	1,000	0	342,000
27	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
28														
29	SULPHUR													
30	KW	119,327	151,864	111,504	125,854	155,264	202,467	202,194	204,733	190,763	120,205	102,894	124,156	1,811,225
31	KWH - TOTAL	62,152,000	55,094,000	42,355,000	35,372,000	60,460,000	71,518,000	73,729,000	76,858,000	66,969,000	58,272,000	50,347,000	66,088,000	719,214,000
32	KWH - BASE RESOURCES	62,145,000	55,075,000	42,226,000	35,359,000	60,437,000	71,515,000	73,721,000	76,858,000	66,964,000	58,271,000	50,321,000	65,976,000	718,868,000
33	KWH - OTHER EXISTING RESOURCES	7,000	19,000	129,000	13,000	23,000	3,000	8,000	0	5,000	1,000	26,000	112,000	346,000
34	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
35														
36	TRICO													
37	KW	93,162	109,942	78,252	93,298	117,654	173,678	170,512	169,634	162,034	124,318	77,608	96,230	1,466,322
38	KWH - TOTAL	49,056,197	44,022,811	42,924,616	45,454,856	51,780,343	71,393,709	77,854,329	81,298,148	65,194,146	51,719,720	42,828,323	53,071,837	676,599,035
39	KWH - BASE RESOURCES	45,133,083	38,207,639	27,237,756	24,614,424	37,461,680	46,622,530	50,598,919	51,339,503	47,940,460	41,414,455	38,368,477	49,937,693	498,876,619
40	KWH - OTHER EXISTING RESOURCES	3,923,114	5,815,172	15,686,860	20,840,432	14,318,663	24,771,179	27,255,410	29,958,645	17,253,686	10,305,265	4,459,846	3,134,144	177,722,416
41	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
42														
43														
44														
45	FULL REQUIREMENTS													
46	KW	33,067	37,116	33,924	33,914	41,392	60,125	57,567	56,689	53,774	36,749	30,878	34,849	510,044
47	KWH - TOTAL	18,524,740	16,370,523	18,222,689	19,237,752	20,121,074	26,811,993	29,899,365	28,625,423	21,809,536	17,062,035	16,720,252	20,171,399	253,576,781
48	KWH - BASE RESOURCES	18,264,934	16,074,113	13,856,885	13,435,744	18,364,406	24,484,409	27,079,114	26,117,651	21,262,542	16,810,853	15,726,626	20,147,896	231,625,173
49	KWH - OTHER EXISTING RESOURCES	259,806	296,410	4,365,804	5,802,008	1,756,668	2,327,584	2,820,251	2,507,772	546,994	251,182	993,626	23,503	21,951,608
50	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
51														
52	PARTIAL REQUIREMENTS													
53	KW	299,851	357,851	271,226	321,097	400,412	551,629	560,105	572,209	532,351	379,092	258,098	307,225	4,811,146
54	KWH - TOTAL	165,936,197	145,084,811	124,211,616	119,081,856	165,252,343	210,882,709	232,541,329	241,725,148	199,039,146	163,705,720	134,070,323	172,711,837	2,074,243,035
55	KWH - BASE RESOURCES	162,006,083	139,242,639	108,150,756	98,227,424	150,910,680	186,107,530	205,219,919	211,738,503	181,780,460	153,399,455	129,583,477	169,465,693	1,895,832,619
56	KWH - OTHER EXISTING RESOURCES	3,930,114	5,842,172	16,060,860	20,854,432	14,341,663	24,775,179	27,321,410	29,986,645	17,258,686	10,306,265	4,486,846	3,246,144	178,410,416
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	332,918	394,967	305,150	355,011	441,804	611,754	617,672	628,898	586,125	415,841	288,976	342,074	5,321,190
61	KWH - TOTAL	184,460,937	161,455,334	142,434,305	138,319,608	185,373,417	237,694,702	262,440,694	270,350,571	220,848,682	180,767,755	150,790,575	192,883,236	2,327,819,816
62	KWH - BASE RESOURCES	180,271,017	155,316,752	122,007,641	111,663,168	169,275,086	210,591,939	232,299,033	237,856,154	203,043,002	170,210,308	145,310,103	189,613,589	2,127,457,792
63	KWH - OTHER EXISTING RESOURCES	4,189,920	6,138,582	20,426,664	26,656,440	16,098,331	27,102,763	30,141,661	32,494,417	17,805,680	10,557,447	5,480,472	3,269,647	200,362,024
64	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0

Arizona Electric Power Cooperative, Inc.

ANZA ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Current Year	6,744	7,368	5,988	5,424	5,760	8,436	10,524	9,396	8,400	6,804	7,164	7,404	89,412
3	kW - 12 Month Average	7,678	7,645	7,617	7,654	7,640	7,683	7,702	7,684	7,594	7,709	7,566	7,451	91,623
4	ARM Load Ratio Share	19.29%	18.96%	18.69%	18.55%	18.46%	18.16%	18.18%	18.13%	17.69%	18.02%	17.83%	17.54%	19.11%
5	KWH - TOTAL	4,257,329	4,142,808	4,173,822	3,770,215	3,927,846	4,098,396	4,852,867	5,136,535	4,269,366	3,812,046	4,034,970	4,770,882	51,247,082
6	KWH - BASE RESOURCES	4,197,622	4,067,797	3,173,855	2,633,137	3,584,926	3,742,609	4,395,121	4,686,541	4,162,288	3,755,926	3,795,186	4,765,323	46,960,331
7	KWH - OTHER EXISTING RESOURCES	59,707	75,011	999,967	1,137,078	342,920	355,787	457,746	449,994	107,078	56,120	239,784	5,559	4,286,751
8														
9	**PRESENT RATES**													
10	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
11	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
12	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
13	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
15	PPFAC-Base	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	
16	PPFAC-Other	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	
17														
18	**PRESENT REVENUES**													
19	Demand Revenue	$125,957	$123,764	$121,999	$121,090	$120,521	$118,548	$118,652	$118,354	$115,460	$117,663	$116,374	$114,534	$1,432,916
20	Base Energy Charge Revenue	132,477	128,380	100,167	83,102	113,140	118,117	138,710	147,907	131,362	118,537	119,776	150,394	1,482,068
21	Other Energy Charge Revenue	3,684	4,628	61,698	70,158	21,158	21,952	28,243	27,765	6,607	3,463	14,795	343	264,493
22	Total Present Base Rate Revenue per Bill	$262,118	$256,772	$283,864	$274,349	$254,820	$258,617	$285,605	$294,026	$253,428	$239,663	$250,944	$265,270	$3,179,476
23	Base PPFAC Revenue Accrued	14,981	19,080	10,352	2,011	10,180	6,511	8,510	16,248	15,426	19,299	22,047	44,553	189,198.22
24	Other PPFAC Revenue Accrued	1488.74	8635.94	(30031.38)	(32513.55)	12842.52	17099.23	4084.84	7351.18	7309.61	5762.90	12859.33	(79864.38)	(64975.02)
25	Total Present Revenue	$278,587	$284,488	$264,184	$243,847	$277,842	$282,227	$298,200	$317,625	$276,164	$264,725	$285,850	$229,959	$3,303,699
26														
27	**PROPOSED RATES**													
28	Fixed Demand Charge	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	
29	O&M Demand Charge	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	
30	Base Resource Energy Charge	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
31	Other Existing Resources Energy Charge	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
32	PPFAC-Base	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
33	PPFAC-Other	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
34														
35	**PROPOSED REVENUES**													
36	Fixed Demand Charge Revenue	$54,127	$53,201	$52,444	$52,051	$51,798	$50,957	$51,013	$50,872	$49,638	$50,564	$50,031	$49,217	$615,913
37	O&M Demand Charge Revenue	88,382	86,870	85,633	84,992	84,579	83,205	83,296	83,067	81,051	82,563	81,693	80,364	1,005,695
38	Base Resource Energy Revenue	122,624	118,831	92,717	76,921	104,725	109,331	128,393	136,906	121,591	109,721	110,867	139,208	1,371,835
39	Other Existing Resources Energy Revenue	2,863	3,597	47,945	54,519	16,442	17,059	21,947	21,576	5,134	2,691	11,497	267	205,534
40	Total Proposed Base Rate Revenue	$267,996	$262,499	$278,738	$268,482	$257,545	$260,551	$284,649	$292,421	$257,414	$245,538	$254,088	$269,055	$3,198,978
41	PPFAC Revenue-Base	0	0	0	0	0	0	0	0	0	0	0	0	0
42	PPFAC Revenue-Other	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Present Revenue	$267,996	$262,499	$278,738	$268,482	$257,545	$260,551	$284,649	$292,421	$257,414	$245,538	$254,088	$269,055	$3,198,978
44														
45	**PROPOSED REVENUE CHANGES**													
46	Change in Fixed and Demand Revenue	$16,552	$16,307	$16,078	$15,953	$15,857	$15,613	$15,657	$15,586	$15,229	$15,464	$15,350	$15,047	$188,693
47	Change in Base Energy Charge Revenue	(9,853)	(9,549)	(7,450)	(6,181)	(8,415)	(8,785)	(10,317)	(11,001)	(9,770)	(8,817)	(8,909)	(11,186)	(110,233)
48	Change in Other Energy Charge Revenue	(821)	(1,032)	(13,753)	(15,639)	(4,716)	(4,893)	(6,296)	(6,189)	(1,473)	(772)	(3,298)	(76)	(58,958)
49	Change in Base Rate Revenue	$5,878	$5,727	($5,126)	($5,867)	$2,725	$1,935	($956)	($1,604)	$3,986	$5,876	$3,143	$3,785	$19,501
50	Change in PPFAC Revenue-Base	(14,981)	(19,080)	(10,352)	(2,011)	(10,180)	(6,511)	(8,510)	(16,248)	(15,426)	(19,299)	(22,047)	(44,553)	(189,198)
51	Change in PPFAC Revenue-Other	(1,489)	(8,636)	30,031	32,514	(12,843)	(17,099)	(4,085)	(7,351)	(7,310)	(5,763)	(12,859)	79,864	64,975
52	Change in Total Revenue	($10,591)	($21,989)	$14,554	$24,635	($20,297)	($21,676)	($13,550)	($25,203)	($18,750)	($19,187)	($31,763)	$39,096	($104,722)
53	Percentage Change in Base Rate Revenue	2.24%	2.23%	-1.81%	-2.14%	1.07%	0.75%	-0.33%	-0.55%	1.57%	2.45%	1.25%	1.43%	0.61%
54	Percentage Change in Total Revenue	-3.80%	-7.73%	5.51%	10.10%	-7.31%	-7.68%	-4.54%	-7.93%	-6.79%	-7.25%	-11.11%	17.00%	-3.17%

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

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Current Year	4,304	5,306	3,854	3,808	5,380	7,406	6,954	6,748	6,084	4,422	3,588	4,132	61,986
3	kW - 12 Month Average	4,798	4,938	4,956	5,002	5,011	5,164	5,191	5,196	5,258	5,237	5,193	5,166	61,110
4	ARM Load Ratio Share	12.06%	12.25%	12.16%	12.12%	12.11%	12.21%	12.25%	12.26%	12.25%	12.25%	12.27%	12.16%	12.18%
5	KWH - TOTAL	2,283,326	2,048,024	2,011,360	2,160,532	2,387,618	3,278,746	3,616,574	3,308,787	2,462,224	1,863,676	1,835,082	2,360,283	29,616,232
6	KWH - BASE RESOURCES	2,251,302	2,010,942	1,529,477	1,508,927	2,179,167	2,994,114	3,275,441	3,018,916	2,400,470	1,836,239	1,726,029	2,357,533	27,088,557
7	KWH - OTHER EXISTING RESOURCES	32,024	37,082	481,883	651,605	208,451	284,632	341,133	289,871	61,754	27,437	109,053	2,750	2,527,675
8														
9	**PRESENT RATES**													
10	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
11	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
12	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
13	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
15	PPFAC-Base	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	
16	PPFAC-Other	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	
17														
18	**PRESENT REVENUES**													
19	Demand Revenue	$78,705	$79,944	$79,379	$79,129	$79,041	$79,675	$79,974	$80,027	$79,941	$79,938	$79,874	$79,402	$955,028
20	Base Energy Charge Revenue	71,051	63,465	48,270	47,622	68,775	94,494	103,373	95,277	75,759	57,952	54,473	74,404	854,915
21	Other Energy Charge Revenue	1,976	2,288	29,732	40,204	12,861	17,562	21,048	17,885	3,810	1,693	6,729	170	155,958
22	Total Present Base Rate Revenue per Bill	$151,732	$145,697	$157,381	$166,954	$160,677	$191,731	$204,395	$193,189	$159,510	$139,582	$141,076	$153,976	$1,965,900
23	PPFAC Revenue-Base,Accrued	8,035	9,432	5,081	1,153	6,175	5,209	6,342	10,467	8,897	9,435	10,027	22,070	102,322
24	PPFAC Revenue-Other, Accrued	798	4,269	(14,472)	(18,632)	7,800	13,680	3,044	4,735	4,216	2,817	5,848	(49,035)	(34,931)
25	Total Present Revenue	$160,565	$159,398	$147,990	$149,475	$174,652	$210,619	$213,781	$208,391	$172,622	$151,835	$156,951	$127,010	$2,033,290
26														
27	**PROPOSED RATES**													
28	Fixed Demand Charge	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	
29	O&M Demand Charge	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	
30	Base Resource Energy Charge	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
31	Other Existing Resources Energy Charge	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
32	PPFAC-Base	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
33	PPFAC-Other	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
34														
35	**PROPOSED REVENUES**													
36	Fixed Demand Charge Revenue	$33,829	$34,362	$34,121	$34,011	$33,975	$34,247	$34,376	$34,399	$34,362	$34,359	$34,415	$34,129	$410,585
37	O&M Demand Charge Revenue	55,238	56,108	55,714	55,535	55,476	55,920	56,131	56,168	56,108	56,104	56,195	55,728	670,425
38	Base Resource Energy Revenue	65,766	58,745	44,680	44,080	63,659	87,466	95,684	88,190	70,124	53,641	50,422	68,870	791,328
39	Other Existing Resources Energy Revenue	1,535	1,778	23,105	31,242	9,994	13,647	16,356	13,898	2,961	1,316	5,229	132	121,193
40	Total Proposed Base Rate Revenue	$156,368	$150,993	$157,619	$164,869	$163,104	$191,280	$202,548	$192,655	$163,555	$145,420	$146,261	$158,859	$1,993,532
41	PPFAC Revenue-Base	0	0	0	0	0	0	0	0	0	0	0	0	0
42	PPFAC Revenue-Other	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Proposed Revenue	$156,368	$150,993	$157,619	$164,869	$163,104	$191,280	$202,548	$192,655	$163,555	$145,420	$146,261	$158,859	$1,993,532
44														
45	**PROPOSED REVENUE CHANGES**													
46	Change in Fixed and Demand Revenue	$10,361	$10,527	$10,456	$10,418	$10,410	$10,492	$10,533	$10,539	$10,530	$10,525	$10,736	$10,455	$125,983
47	Change in Base Energy Charge Revenue	(5,285)	(4,720)	(3,590)	(3,542)	(5,115)	(7,028)	(7,689)	(7,086)	(5,635)	(4,310)	(4,052)	(5,534)	(63,587)
48	Change in Other Energy Charge Revenue	(440)	(510)	(6,628)	(8,962)	(2,867)	(3,915)	(4,692)	(3,987)	(849)	(377)	(1,500)	(38)	(34,765)
49	Change in Base Rate Revenue	$4,636	$5,296	$238	($2,086)	$2,428	($451)	($1,848)	($534)	$4,046	$5,837	$5,185	$4,883	$27,631
50	Change in PPFAC Revenue-Base	(8,035)	(9,432)	(5,081)	(1,153)	(6,175)	(5,209)	(6,342)	(10,467)	(8,897)	(9,435)	(10,027)	(22,070)	(102,322)
51	Change in PPFAC Revenue-Other	(798)	(4269)	14472	18632	(7800)	(13680)	(3044)	(4735)	(4216)	(2817)	(5848)	49035	34931
52	Change in Total Revenue	($4,197)	($8,405)	$9,629	$15,394	($11,548)	($19,339)	($11,234)	($15,736)	($9,067)	($6,415)	($10,690)	$31,848	($39,759)
53	Percentage Change in Base Rate Revenue	3.06%	3.64%	0.15%	-1.25%	1.51%	-0.23%	-0.90%	-0.28%	2.54%	4.18%	3.68%	3.17%	1.41%
54	Percentage Change in Total Revenue	-2.61%	-5.27%	6.51%	10.30%	-6.61%	-9.18%	-5.25%	-7.55%	-5.25%	-4.23%	-6.81%	25.08%	-1.96%

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

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Current Year	22,019	24,442	24,082	24,682	30,252	44,283	40,089	40,545	39,290	25,523	20,126	23,313	358,646
3	kW - 12 Month Average	28,786	27,741	28,185	28,608	28,732	29,462	29,482	29,504	30,085	29,824	29,683	29,852	349,944
4	ARM Load Ratio Share	68.65%	68.80%	69.15%	69.33%	69.43%	69.64%	69.57%	69.61%	70.07%	69.73%	69.94%	70.29%	68.71%
5	KWH - TOTAL	11,984,085	10,179,691	12,037,507	13,307,005	13,805,610	19,434,851	21,429,924	20,180,101	15,077,946	11,386,313	10,850,200	13,040,234	172,713,467
6	KWH - BASE RESOURCES	11,816,010	9,995,374	9,153,553	9,293,680	12,600,313	17,747,686	19,408,552	18,412,194	14,699,784	11,218,688	10,205,411	13,025,040	157,576,285
7	KWH - OTHER EXISTING RESOURCES	168,075	184,317	2,883,954	4,013,325	1,205,297	1,687,165	2,021,372	1,767,907	378,162	167,625	644,789	15,194	15,137,182
8														
9	**PRESENT RATES**													
10	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
11	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
12	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
13	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
14	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
15	PPFAC-Base	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	$0.03361	
16	PPFAC-Other	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	$0.07941	
17														
18	**PRESENT REVENUES**													
19	Demand Revenue	$448,150	$449,104	$451,434	$452,594	$453,250	$454,589	$454,185	$454,431	$457,411	$455,211	$456,564	$458,876	$5,445,801
20	Base Energy Charge Revenue	372,913	315,454	288,886	293,309	397,666	560,117	612,534	581,089	463,925	354,062	322,083	411,070	4,973,108
21	Other Energy Charge Revenue	10,370	11,372	177,940	247,622	74,367	104,098	124,719	109,080	23,333	10,342	39,783	937	933,964
22	Total Present Base Rate Revenue per Bill	$831,433	$775,930	$918,260	$993,524	$925,283	$1,118,804	$1,191,438	$1,144,600	$944,669	$819,615	$818,431	$870,884	$11,352,872
23	PPFAC Revenue-Base,Accrued	42,169	46,884	29,183	7,099	35,774	30,876	37,578	63,835	54,480	57,645	59,285	122,148	586,957
24	PPFAC Revenue-Other, Accrued	4,190	21,220	(86,612)	(114,757)	45,115	81,086	18,038	28,881	25,815	17,213	34,579	(288,221)	(213,452)
25	Total Present Revenue	$877,792	$844,034	$860,832	$885,867	$1,006,172	$1,230,766	$1,247,054	$1,237,316	$1,024,964	$894,474	$912,294	$704,811	$11,726,376
26														
27	**PROPOSED RATES**													
28	Fixed Demand Charge	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	
29	O&M Demand Charge	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	
30	Base Resource Energy Charge	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
31	Other Existing Resources Energy Charge	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
32	PPFAC-Base	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
33	PPFAC-Other	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
34														
35	**PROPOSED REVENUES**													
36	Fixed Demand Charge Revenue	$192,628	$193,038	$194,039	$194,539	$194,819	$195,397	$195,223	$195,327	$196,610	$195,664	$196,245	$197,238	$2,340,768
37	O&M Demand Charge Revenue	314,533	315,202	316,837	317,653	318,111	319,055	318,771	318,940	321,034	319,490	320,439	322,061	3,822,127
38	Base Resource Energy Revenue	345,177	291,991	267,399	271,493	368,088	518,457	566,975	537,869	429,419	327,727	298,127	380,496	4,603,219
39	Other Existing Resources Energy Revenue	8,059	8,837	138,275	192,424	57,790	80,893	96,917	84,765	18,131	8,037	30,915	728	725,773
40	Total Proposed Base Rate Revenue	$860,396	$809,068	$916,551	$976,109	$938,809	$1,113,803	$1,177,887	$1,136,901	$965,195	$850,919	$845,726	$900,523	$11,491,886
41	PPFAC Revenue-Base	0	0	0	0	0	0	0	0	0	0	0	0	0
42	PPFAC Revenue-Other	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Proposed Revenue	$860,396	$809,068	$916,551	$976,109	$938,809	$1,113,803	$1,177,887	$1,136,901	$965,195	$850,919	$845,726	$900,523	$11,491,886
44														
45	***PROPOSED REVENUE CHANGES***													
46	Change in Fixed and Demand Revenue	$59,011	$59,135	$59,443	$59,598	$59,680	$59,863	$59,809	$59,836	$60,232	$59,943	$60,119	$60,423	$717,094
47	Change in Base Energy Charge Revenue	(27,736)	(23,463)	(21,487)	(21,816)	(29,578)	(41,660)	(45,559)	(43,220)	(34,506)	(26,334)	(23,956)	(30,574)	(369,889)
48	Change in Other Energy Charge Revenue	(2,312)	(2,535)	(39,665)	(55,198)	(16,577)	(23,205)	(27,801)	(24,315)	(5,201)	(2,305)	(8,868)	(209)	(208,191)
49	Change in Base Rate Revenue	28,963	33,138	(1,709)	(17,415)	13,526	(5,002)	(13,551)	(7,699)	20,526	31,303	27,295	29,639	139,014
50	Change in PPFAC Revenue-Base	(42,169)	(46,884)	(29,183)	(7,099)	(35,774)	(30,876)	(37,578)	(63,835)	(54,480)	(57,645)	(59,285)	(122,148)	(586,957)
51	Change in PPFAC Revenue-Other	(4,190)	(21,220)	86,612	114,757	(45,115)	(81,086)	(18,038)	(28,881)	(25,815)	(17,213)	(34,579)	288,221	213,452
52	Change in Total Revenue	($17,396)	($34,966)	$55,720	$90,242	($67,364)	($116,964)	($69,167)	($100,414)	($59,769)	($43,555)	($66,569)	$195,712	($234,490)
53	Percentage Change in Base Rate Revenue	3.48%	4.27%	-0.19%	-1.75%	1.46%	-0.45%	-1.14%	-0.67%	2.17%	3.82%	3.34%	3.40%	1.22%
54	Percentage Change in Total Revenue	-1.98%	-4.14%	6.47%	10.19%	-6.70%	-9.50%	-5.55%	-8.12%	-5.83%	-4.87%	-7.30%	27.77%	-2.00%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	KWH - TOTAL	54,728,000	45,968,000	38,932,000	38,255,000	53,012,000	67,971,000	80,958,000	83,569,000	66,876,000	53,714,000	40,895,000	53,552,000	678,430,000
3	KWH - BASE RESOURCES	54,728,000	45,960,000	38,687,000	38,254,000	53,012,000	67,970,000	80,900,000	83,541,000	66,876,000	53,714,000	40,894,000	53,552,000	678,088,000
4	KWH - OTHER EXISTING RESOURCES	0	8,000	245,000	1,000	0	1,000	58,000	28,000	0	0	1,000	0	342,000
5														
6	**PRESENT RATES**													
7	Fixed Demand Charge	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	
8	O&M Demand Charge	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	
9	Base Resource Energy Charge	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	
10	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	
11	Additional ARM Resources	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
12	PPFAC-Base	$0.03330	$0.03330	$0.03330	$0.03330	$0.03330	$0.03330	$0.03330	$0.03330	$0.03330	$0.03330	$0.03330	$0.03330	
13	PPFAC-Other	$0.06971	$0.06971	$0.06971	$0.06971	$0.06971	$0.06971	$0.06971	$0.06971	$0.06971	$0.06971	$0.06971	$0.06971	
14														
15	**PRESENT REVENUES**													
16	Demand Charge Revenue	$2,002,165	$2,002,165	$2,002,165	$2,002,165	$2,002,165	$2,002,165	$2,002,165	$2,002,165	$2,002,165	$1,965,442	$2,002,165	$2,002,165	23,989,257
17	Base Energy Charge Revenue	1,759,505	1,477,614	1,243,787	1,229,866	1,704,336	2,185,236	2,600,935	2,685,843	2,150,063	1,726,905	1,314,742	1,721,697	21,800,529
18	Other Energy Charge Revenue	0	550	16,854	69	0	69	3,990	1,926	0	0	69	0	23,526
19	Total Present Base Rate Revenue per Bill	$3,761,670	$3,480,329	$3,262,806	$3,232,100	$3,706,501	$4,187,469	$4,607,090	$4,689,934	$4,152,228	$3,692,347	$3,316,976	$3,723,862	45,813,313
20	PPFAC Revenue-Base,Accrued	227,325	256,977	218,076	133,255	210,187	175,081	207,146	320,769	265,844	287,081	341,369	642,141	3,285,252
21	PPFAC Revenue-Other, Accrued	0	(320)	4,719	(46)	10	70	(1,588)	723	0	0	92	(11,348)	(7,688)
22	Total Present Revenue	$3,988,995	$3,736,986	$3,485,601	$3,365,309	$3,916,698	$4,362,621	$4,812,648	$5,011,426	$4,418,073	$3,979,428	$3,658,436	$4,354,655	49,090,876
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	
26	O&M Demand Charge	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	
27	Base Resource Energy Charge	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	
28	Other Existing Resources Energy Charge	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	
29	PPFAC-Base	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	
30	PPFAC-Other	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	10,276,259
34	O&M Demand Charge Revenue	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	17,028,710
35	Base Resource Energy Revenue	1,584,075	1,330,290	1,119,776	1,107,243	1,534,406	1,967,358	2,341,611	2,418,053	1,935,693	1,554,725	1,183,657	1,550,036	19,626,925
36	Other Existing Resources Energy Revenue	0	435	13,320	54	0	54	3,153	1,522	0	0	54	0	18,594
37	Total Proposed Base Rate Revenue	$3,859,489	$3,606,139	$3,408,511	$3,382,712	$3,809,820	$4,242,827	$4,620,178	$4,694,990	$4,211,107	$3,830,139	$3,459,125	$3,825,450	46,950,488
38	PPFAC Revenue-Base	0	0	0	0	0	0	0	0	0	0	0	0	0
39	PPFAC Revenue-Other	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$3,859,489	$3,606,139	$3,408,511	$3,382,712	$3,809,820	$4,242,827	$4,620,178	$4,694,990	$4,211,107	$3,830,139	$3,459,125	$3,825,450	46,950,488
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$273,249	$273,249	$273,249	$273,249	$273,249	$273,249	$273,249	$273,249	$273,249	$309,972	$273,249	$273,249	$3,315,712
44	Change in Base Energy Charge Revenue	(175,430)	(147,324)	(124,011)	(122,623)	(169,929)	(217,877)	(259,324)	(267,790)	(214,370)	(172,180)	(131,085)	(171,661)	(2,173,604)
45	Change in Other Energy Charge Revenue	0	(115)	(3,533)	(14)	0	(14)	(836)	(404)	0	0	(15)	0	(4,932)
46	Change in Base Rate Revenue	$97,819	$125,809	$145,705	$150,612	$103,320	$55,358	$13,088	$5,055	$58,879	$137,792	$142,149	$101,588	$1,137,175
47	Change in PPFAC Revenue-Base	(227,325)	(256,977)	(218,076)	(133,255)	(210,187)	(175,081)	(207,146)	(320,769)	(265,844)	(287,081)	(341,369)	(642,141)	(3,285,252)
48	Change in PPFAC Revenue-Other	0	320	(4,719)	46	(10)	(70)	1,588	(723)	0	0	(92)	11,348	7,688
49	Change in Total Revenue	($129,506)	($130,848)	($77,090)	$17,403	($106,878)	($119,794)	($192,469)	($316,437)	($206,965)	($149,289)	($199,311)	($529,204)	($2,140,388)
50	Percentage Change in Base Rate Revenue	2.60%	3.61%	4.47%	4.66%	2.79%	1.32%	0.28%	0.11%	1.42%	3.73%	4.29%	2.73%	2.48%
51	Percentage Change in Total Revenue	-3.25%	-3.50%	-2.21%	0.52%	-2.73%	-2.75%	-4.00%	-6.31%	-4.68%	-3.75%	-5.45%	-12.15%	-4.36%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	KWH - TOTAL	62,152,000	55,094,000	42,355,000	35,372,000	60,460,000	71,518,000	73,729,000	76,858,000	66,969,000	58,272,000	50,347,000	66,088,000	719,214,000
3	KWH - BASE RESOURCES	62,152,000	55,094,000	42,355,000	35,372,000	60,460,000	71,518,000	73,729,000	76,858,000	66,969,000	58,272,000	50,347,000	66,088,000	719,214,000
4	KWH - OTHER EXISTING RESOURCES	7,000	19,000	129,000	13,000	23,000	3,000	8,000	0	5,000	1,000	26,000	112,000	346,000
5														
6	**PRESENT RATES**													
7	Fixed Demand Charge	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	
8	O&M Demand Charge	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	
9	Base Resource Energy Charge	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	
10	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	
11	Additional ARM Resources	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
12	PPFAC-Base	$0.03337	$0.03337	$0.03337	$0.03337	$0.03337	$0.03337	$0.03337	$0.03337	$0.03337	$0.03337	$0.03337	$0.03337	
13	PPFAC-Other	$0.07241	$0.07241	$0.07241	$0.07241	$0.07241	$0.07241	$0.07241	$0.07241	$0.07241	$0.07241	$0.07241	$0.07241	
14														
15	**PRESENT REVENUES**													
16	Fixed Demand Charge Revenue	$1,772,867	$1,772,867	$1,772,867	$1,772,867	$1,773,165	$1,772,867	$1,772,867	$1,772,867	$1,772,867	$1,772,867	$1,772,867	$1,772,867	$21,274,702
17	Base Energy Charge Revenue	2,006,662	1,778,372	1,363,478	1,141,742	1,951,511	2,309,219	2,380,451	2,481,745	2,162,268	1,881,571	1,624,865	2,130,365	23,212,248
18	Other Energy Charge Revenue	467	1,268	8,612	868	1,535	200	534	0	334	67	1,736	7,477	23,099
19	Total Present Base Rate Revenue per Bill	$3,779,996	$3,552,507	$3,144,957	$2,915,477	$3,726,212	$4,082,287	$4,153,852	$4,254,612	$3,935,468	$3,654,505	$3,399,468	$3,910,709	$44,510,050
20	PPFAC Revenue-Base,Accrued	195,902	224,489	173,154	110,415	140,787	140,835	178,153	275,290	228,591	233,041	260,038	512,014	2,672,708.37
21	PPFAC Revenue-Other, Accrued	589	2,152	1,244	418	(927)	47	(337)	0	388	(50)	(574)	52,814	55,764
22	Total Present Revenue	$3,976,488	$3,779,148	$3,319,355	$3,026,310	$3,866,071	$4,223,168	$4,331,668	$4,529,902	$4,164,446	$3,887,497	$3,658,932	$4,475,537	$47,238,522
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	
26	O&M Demand Charge	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	
27	Base Resource Energy Charge	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	
28	Other Existing Resources Energy Charge	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	
29	PPFAC-Base	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	
30	PPFAC-Other	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$9,099,369
34	O&M Demand Charge Revenue	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	15,078,494
35	Base Resource Energy Revenue	1,826,183	1,618,801	1,244,497	1,039,319	1,776,468	2,101,380	2,166,344	2,258,282	1,967,719	1,712,179	1,479,322	1,941,833	21,132,326
36	Other Existing Resources Energy Revenue	358	971	6,591	664	1,175	153	409	0	255	51	1,328	5,723	17,678
37	Total Proposed Base Rate Revenue	$3,841,363	$3,634,594	$3,265,910	$3,054,805	$3,792,465	$4,116,355	$4,181,575	$4,273,104	$3,982,796	$3,727,052	$3,495,473	$3,962,377	$45,327,868
38	PPFAC Revenue-Base	0	0	0	0	0	0	0	0	0	0	0	0	0
39	PPFAC Revenue-Other	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$3,841,363	$3,634,594	$3,265,910	$3,054,805	$3,792,465	$4,116,355	$4,181,575	$4,273,104	$3,982,796	$3,727,052	$3,495,473	$3,962,377	$45,327,868
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$241,955	$241,955	$241,955	$241,955	$241,657	$241,955	$241,955	$241,955	$241,955	$241,955	$241,955	$241,955	$2,903,161
44	Change in Base Energy Charge Revenue	(180,479)	(159,571)	(118,981)	(102,423)	(175,043)	(207,840)	(214,107)	(223,462)	(194,549)	(169,392)	(145,543)	(188,532)	(2,079,922)
45	Change in Other Energy Charge Revenue	(110)	(298)	(2,021)	(204)	(360)	(47)	(125)	0	(78)	(16)	(408)	(1,754)	(5,421)
46	Change in Base Rate Revenue	$61,366	$82,087	$120,953	$139,328	$66,253	$34,068	$27,723	$18,493	$47,328	$72,547	$96,005	$51,668	$817,818
47	Change in PPFAC Revenue-Base	(195,902)	(224,489)	(173,154)	(110,415)	(140,787)	(140,835)	(178,153)	(275,290)	(228,591)	(233,041)	(260,038)	(512,014)	(2,672,708)
48	Change in PPFAC Revenue-Other	(589)	(2,152)	(1,244)	(418)	927	(47)	337	0	(388)	50	574	(52,814)	(55,764)
49	Change in Total Revenue	($135,125)	($144,555)	($53,445)	$28,495	($73,606)	($106,813)	($150,093)	($256,797)	($181,650)	($160,445)	($163,459)	($513,160)	($1,910,654)
50	Percentage Change in Base Rate Revenue	1.62%	2.31%	3.85%	4.78%	1.78%	0.83%	0.67%	0.43%	1.20%	1.99%	2.82%	1.32%	1.84%
51	Percentage Change in Total Revenue	-3.40%	-3.83%	-1.61%	0.94%	-1.90%	-2.53%	-3.47%	-5.67%	-4.36%	-4.13%	-4.47%	-11.47%	-4.04%

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

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	KWH - TOTAL	49,056,197	44,022,811	42,924,616	45,454,856	51,780,343	71,393,709	77,854,329	81,298,148	65,194,146	51,719,720	42,828,323	53,071,837	676,599,035
3	KWH - BASE RESOURCES	45,133,083	38,207,639	27,237,756	24,614,424	37,461,680	46,622,530	50,598,919	51,339,503	47,940,460	41,414,455	38,368,477	49,937,693	498,876,619
4	KWH - OTHER EXISTING RESOURCES	3,923,114	5,815,172	15,686,860	20,840,432	14,318,663	24,771,179	27,255,410	29,958,645	17,253,686	10,305,265	4,459,846	3,134,144	177,722,416
5														
6	**PRESENT RATES**													
7	Fixed Demand Charge	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	
8	O&M Demand Charge	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	
9	Base Resource Energy Charge	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	
10	Other Existing Resources Energy Charge	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
11	Additional ARM Resources	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
12	PPFAC-Base	$0.03336	$0.03336	$0.03336	$0.03336	$0.03336	$0.03336	$0.03336	$0.03336	$0.03336	$0.03336	$0.03336	$0.03336	
13	PPFAC-Other	$0.09084	$0.09084	$0.09084	$0.09084	$0.09084	$0.09084	$0.09084	$0.09084	$0.09084	$0.09084	$0.09084	$0.09084	
14														
15	**PRESENT REVENUES**													
16	Demand Revenue	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$1,410,900	$16,930,800
17	Base Energy Charge Revenue	1,461,409	1,237,163	881,959	797,015	1,213,009	1,509,638	1,638,393	1,662,373	1,552,312	1,341,000	1,242,371	1,616,983	16,153,625
18	Other Energy Charge Revenue	259,082	384,034	1,035,960	1,376,302	945,605	1,635,889	1,799,947	1,978,469	1,139,433	680,560	294,528	206,978	11,736,787
19	Total Present Base Rate Revenue per Bill	$3,131,392	$3,032,097	$3,328,819	$3,584,217	$3,569,514	$4,556,426	$4,849,240	$5,051,742	$4,102,646	$3,432,460	$2,947,799	$3,234,861	$44,821,212
20	PPFAC Revenue-Base,Accrued	120,706	135,081	81,417	8,806	73,041	58,209	81,340	146,131	120,693	129,238	147,961	321,054	1,423,676
21	PPFAC Revenue-Other, Accrued	82,375	(85,552)	(864,788)	(875,841)	(3,951)	(474,483)	(576,925)	(585,186)	23,918	154,544	110,700	(1,332,483)	(4,427,672)
22	Total Present Revenue	$3,334,473	$3,081,626	$2,545,448	$2,717,182	$3,638,604	$4,140,153	$4,353,656	$4,612,686	$4,247,256	$3,716,242	$3,206,460	$2,223,431	$41,817,216
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	
26	O&M Demand Charge	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	
27	Base Resource Energy Charge	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	
28	Other Existing Resources Energy Charge	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	
29	PPFAC-Base	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	
30	PPFAC-Other	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$8,925,935
34	O&M Demand Charge Revenue	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	10,318,076
35	Base Resource Energy Revenue	1,330,152	1,126,047	802,745	725,431	1,104,062	1,374,048	1,491,240	1,513,066	1,412,890	1,220,557	1,130,787	1,471,752	14,702,775
36	Other Existing Resources Energy Revenue	165,520	245,347	661,842	879,276	604,117	1,045,118	1,149,930	1,263,981	727,948	434,788	188,165	132,232	7,498,264
37	Total Proposed Base Rate Revenue	$3,099,339	$2,975,061	$3,068,255	$3,208,374	$3,311,846	$4,022,834	$4,244,837	$4,380,715	$3,744,506	$3,259,013	$2,922,619	$3,207,652	$41,445,050
38	PPFAC Revenue-Base	0	0	0	0	0	0	0	0	0	0	0	0	0
39	PPFAC Revenue-Other	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$3,099,339	$2,975,061	$3,068,255	$3,208,374	$3,311,846	$4,022,834	$4,244,837	$4,380,715	$3,744,506	$3,259,013	$2,922,619	$3,207,652	$41,445,050
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$192,768	$192,768	$192,768	$192,768	$192,768	$192,768	$192,768	$192,768	$192,768	$192,768	$192,768	$192,768	$2,313,211
44	Change in Base Energy Charge Revenue	(131,258)	(111,117)	(79,214)	(71,584)	(108,947)	(135,589)	(147,153)	(149,307)	(139,422)	(120,443)	(111,584)	(145,231)	(1,450,850)
45	Change in Other Energy Charge Revenue	(93,563)	(138,687)	(374,118)	(497,026)	(341,488)	(590,771)	(650,018)	(714,488)	(411,485)	(245,772)	(106,363)	(74,746)	(4,238,524)
46	Change in Base Rate Revenue	($32,053)	($57,036)	($260,564)	($375,843)	($257,667)	($533,593)	($604,404)	($671,027)	($358,140)	($173,447)	($25,180)	($27,209)	($3,376,162)
47	Change in PPFAC Revenue-Base	(120,706)	(135,081)	(81,417)	(8,806)	(73,041)	(58,209)	(81,340)	(146,131)	(120,693)	(129,238)	(147,961)	(321,054)	(1,423,676)
48	Change in PPFAC Revenue-Other	(82,375)	85,552	864,788	875,841	3,951	474,483	576,925	585,186	(23,918)	(154,544)	(110,700)	1,332,483	4,427,672
49	Change in Total Revenue	($235,134)	($106,565)	$522,807	$491,192	($326,757)	($117,319)	($108,819)	($231,971)	($502,751)	($457,229)	($283,840)	$984,221	($372,166)
50	Percentage Change in Base Rate Revenue	-1.02%	-1.88%	-7.83%	-10.49%	-7.22%	-11.71%	-12.46%	-13.28%	-8.73%	-5.05%	-0.85%	-0.84%	-7.53%
51	Percentage Change in Total Revenue	-7.05%	-3.46%	20.54%	18.08%	-8.98%	-2.83%	-2.50%	-5.03%	-11.84%	-12.30%	-8.85%	44.27%	-0.89%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**PRESENT REVENUES**													
2	TOTAL CLASS A													
3	Demand Revenue	$5,838,744	$5,838,744	$5,838,744	$5,838,744	$5,839,042	$5,838,744	$5,838,744	$5,838,744	$5,838,744	$5,802,021	$5,838,744	$5,838,744	$70,028,504
4	Base Energy Revenue	5,804,018	5,000,448	3,926,546	3,592,655	5,448,436	6,776,820	7,474,396	7,654,234	6,535,689	5,480,027	4,678,310	6,104,913	68,476,493
5	Other Energy Charge Revenue	275,580	404,141	1,330,796	1,735,223	1,055,526	1,779,770	1,978,481	2,135,125	1,173,517	696,125	357,640	215,905	13,137,827
6	Total Present Base Rate Revenue	11,918,342	11,243,333	11,096,086	11,166,622	12,343,005	14,395,334	15,291,621	15,628,103	13,547,950	11,978,173	10,874,694	12,159,562	$151,642,824
7	PPFAC Revenue-Base,Accrued	609,117	691,944	517,263	262,738	476,144	416,722	519,068	832,739	693,930	735,741	840,726	1,663,980	8,260,113
8	PPFAC Revenue-Other, Accrued	89,441	(49,596)	(989,940)	(1,041,371)	60,890	(362,501)	(553,682)	(543,496)	61,646	180,288	163,504	(1,708,138)	(4,692,956)
9	Total Adjusted Present Revenue	$12,616,900	$11,885,682	$10,623,410	$10,387,990	$12,880,039	$14,449,555	$15,257,006	$15,917,346	$14,303,525	$12,894,201	$11,878,924	$12,115,404	$155,209,980
10														
11	**PROPOSED REVENUES**													
12	TOTAL CLASS A													
13	Demand Revenue	$6,632,640	$6,632,685	$6,632,692	$6,632,685	$6,632,663	$6,632,685	$6,632,714	$6,632,677	$6,632,707	$6,632,648	$6,632,921	$6,632,640	$79,592,357
14	Base Energy Revenue	$5,273,977	$4,544,705	$3,571,814	$3,264,486	$4,951,409	$6,158,041	$6,790,247	$6,952,367	$5,937,437	$4,978,551	$4,253,182	$5,552,194	62,228,408
15	Other Energy Charge Revenue	178,334	260,965	891,078	1,158,180	689,518	1,156,924	1,288,712	1,385,742	754,430	446,882	237,188	139,082	8,587,036
16	Total Proposed Base Rate Revenue	$12,084,951	$11,438,354	$11,095,584	$11,055,351	$12,273,589	$13,947,650	$14,711,674	$14,970,787	$13,324,573	$12,058,081	$11,123,291	$12,323,916	$150,407,801
17	PPFAC Revenue-Base	0	0	0	0	0	0	0	0	0	0	0	0	0
18	PPFAC Revenue-Other	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Total Adjusted Proposed Revenue	$12,084,951	$11,438,354	$11,095,584	$11,055,351	$12,273,589	$13,947,650	$14,711,674	$14,970,787	$13,324,573	$12,058,081	$11,123,291	$12,323,916	$150,407,801
20														
21	**PROPOSED REVENUE CHANGES**													
22	COLLECTIVE ALL REQUIREMENTS													
23	Change in Fixed and Demand Revenue	$85,925	$85,969	$85,976	$85,969	$85,947	$85,969	$85,999	$85,962	$85,991	$85,932	$86,205	$85,925	$1,031,769
24	Change in Base Energy Charge Revenue	(42,874)	(37,732)	(32,527)	(31,539)	(43,108)	(57,474)	(63,564)	(61,308)	(49,911)	(39,461)	(36,916)	(47,294)	(543,708)
25	Change in Other Energy Charge Revenue	(3,573)	(4,077)	(60,046)	(79,799)	(24,161)	(32,013)	(38,789)	(34,491)	(7,523)	(3,455)	(13,666)	(323)	(301,914)
26	Change in Base Rate Revenue	$39,477	$44,161	($6,596)	($25,368)	$18,678	($3,517)	($16,355)	($9,837)	$28,557	$43,016	$35,623	$38,307	$186,147
27	Change in PPFAC Revenue-Base	(65,185)	(75,397)	(44,616)	(10,263)	(52,129)	(42,597)	(52,429)	(90,549)	(78,802)	(86,380)	(91,358)	(188,771)	(878,476)
28	Change in PPFAC Revenue-Other	(6,477)	(34,125)	131,115	165,902	(65,758)	(111,864)	(25,167)	(40,967)	(37,340)	(25,794)	(53,287)	417,120	313,359
29	Change in Total Revenue	($32,184)	($65,361)	$79,903	$130,271	($99,209)	($157,978)	($93,951)	($141,354)	($87,585)	($69,157)	($109,022)	$266,656	($378,971)
30	Percentage Change in Base Rate Revenue	0.37%	0.44%	-0.07%	-0.26%	0.17%	-0.03%	-0.12%	-0.07%	0.23%	0.40%	0.37%	0.35%	0.14%
31	Percentage Change in Total Revenue	-2.44%	-5.07%	6.28%	10.18%	-6.80%	-9.17%	-5.34%	-8.02%	-5.94%	-5.28%	-8.05%	25.11%	-2.22%
32														
33	PARTIAL REQUIREMENTS													
34	Change in Fixed and Demand Revenue	$707,972	$707,972	$707,972	$707,972	$707,673	$707,972	$707,972	$707,972	$707,972	$744,695	$707,972	$707,972	$8,532,084
35	Change in Base Energy Charge Revenue	(487,167)	(418,012)	(322,205)	(296,631)	(453,920)	(561,306)	(620,584)	(640,560)	(548,341)	(462,015)	(388,212)	(505,424)	(5,704,376)
36	Change in Other Energy Charge Revenue	(93,673)	(139,100)	(379,672)	(497,244)	(341,848)	(590,832)	(650,980)	(714,891)	(411,564)	(245,788)	(106,785)	(76,500)	(4,248,877)
37	Change in Base Rate Revenue	$127,132	$150,860	$6,094	($85,903)	($88,094)	($444,167)	($563,592)	($647,479)	($251,933)	$36,892	$212,974	$126,048	($1,421,169)
38	Change in PPFAC Revenue-Base	(543,933)	(616,548)	(472,647)	(252,475)	(424,015)	(374,125)	(466,639)	(742,190)	(615,128)	(649,361)	(749,368)	(1,475,208)	(7,381,636)
39	Change in PPFAC Revenue-Other	(82,965)	83,721	858,824	875,468	4,868	474,366	578,849	584,464	(24,306)	(154,494)	(110,217)	1,291,018	4,379,597
40	Change in Total Revenue	($499,765)	($381,967)	$392,272	$537,090	($507,241)	($343,926)	($451,381)	($805,205)	($891,367)	($766,963)	($646,611)	($58,143)	($4,423,208)
41	Percentage Change in Base Rate Revenue	1.19%	1.50%	0.06%	-0.88%	-0.80%	-3.46%	-4.14%	-4.63%	-2.07%	0.34%	2.20%	1.16%	-1.05%
42	Percentage Change in Total Revenue	-4.42%	-3.60%	4.20%	5.90%	-4.44%	-2.70%	-3.34%	-5.69%	-6.95%	-6.62%	-6.14%	-0.53%	-3.20%
43														
44	TOTAL CLASS A													
45	Change in Fixed and Demand Revenue	$793,896	$793,941	$793,948	$793,941	$793,620	$793,941	$793,970	$793,933	$793,963	$830,627	$794,177	$793,896	$9,563,853
46	Change in Base Energy Charge Revenue	(530,041)	(455,744)	(354,732)	(328,169)	(497,028)	(618,780)	(684,149)	(701,867)	(598,252)	(501,476)	(425,128)	(552,718)	(6,248,084)
47	Change in Other Energy Charge Revenue	(97,246)	(143,177)	(439,718)	(577,043)	(366,009)	(622,845)	(689,768)	(749,382)	(419,087)	(249,242)	(120,451)	(76,823)	(4,550,791)
48	Change in Base Rate Revenue	$166,609	$195,021	($502)	($111,271)	($69,416)	($447,684)	($579,947)	($657,316)	($223,376)	$79,908	$248,597	$164,355	($1,235,022)
49	Change in PPFAC Revenue-Base	(609,117)	(691,944)	(517,263)	(262,738)	(476,144)	(416,722)	(519,068)	(832,739)	(693,930)	(735,741)	(840,726)	(1,663,980)	(8,260,113)
50	Change in PPFAC Revenue-Other	(89,441)	49,596	989,940	1,041,371	(60,890)	362,501	553,682	543,496	(61,646)	(180,288)	(163,504)	1,708,138	4,692,956
51	Change in Total Revenue	($531,949)	($447,328)	$472,175	$667,361	($606,450)	($501,905)	($545,332)	($946,559)	($978,952)	($836,120)	($755,632)	$208,513	($4,802,179)
52	Percentage Change in Base Rate Revenue	1.40%	1.73%	0.00%	-1.00%	-0.56%	-3.11%	-3.79%	-4.21%	-1.65%	0.67%	2.29%	1.35%	-0.81%
53	Percentage Change in Total Revenue	-4.22%	-3.76%	4.44%	6.42%	-4.71%	-3.47%	-3.57%	-5.95%	-6.84%	-6.48%	-6.36%	1.72%	-3.09%

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

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**AVERAGE COST PER KWH - PRESENT REVENUES**													
2	ANZA	$0.06544	$0.06867	$0.06330	$0.06468	$0.07074	$0.06886	$0.06145	$0.06184	$0.06469	$0.06944	$0.07084	$0.04820	$0.06447
3	DUNCAN	$0.07032	$0.07783	$0.07358	$0.06918	$0.07315	$0.06424	$0.05911	$0.06298	$0.07011	$0.08147	$0.08553	$0.05381	$0.06865
4	GRAHAM	$0.07325	$0.08291	$0.07151	$0.06657	$0.07288	$0.06333	$0.05819	$0.06131	$0.06798	$0.07856	$0.08408	$0.05405	$0.06789
5	MOHAVE	$0.07289	$0.08130	$0.08953	$0.08797	$0.07388	$0.06418	$0.05945	$0.05997	$0.06606	$0.07409	$0.08946	$0.08132	$0.07236
6	SULPHER	$0.06398	$0.06859	$0.07837	$0.08556	$0.06394	$0.05905	$0.05875	$0.05894	$0.06218	$0.06671	$0.07267	$0.06772	$0.06568
7	TRICO	$0.06797	$0.07000	$0.05930	$0.05978	$0.07027	$0.05799	$0.05592	$0.05674	$0.06515	$0.07185	$0.07487	$0.04189	$0.06181
8	AEPCO CLASS A	$0.06840	$0.07362	$0.07458	$0.07510	$0.06948	$0.06079	$0.05814	$0.05888	$0.06477	$0.07133	$0.07878	$0.06281	$0.06668
9														
10	**AVERAGE COST PER KWH - PROPOSED REVENUES**													
11	ANZA	$0.06295	$0.06336	$0.06678	$0.07121	$0.06557	$0.06357	$0.05866	$0.05693	$0.06029	$0.06441	$0.06297	$0.05640	$0.06242
12	DUNCAN	$0.06848	$0.07373	$0.07836	$0.07631	$0.06831	$0.05834	$0.05601	$0.05823	$0.06643	$0.07803	$0.07970	$0.06730	$0.06731
13	GRAHAM	$0.07179	$0.07948	$0.07614	$0.07335	$0.06800	$0.05731	$0.05496	$0.05634	$0.06401	$0.07473	$0.07795	$0.06906	$0.06654
14	MOHAVE	$0.07052	$0.07845	$0.08755	$0.08843	$0.07187	$0.06242	$0.05707	$0.05618	$0.06297	$0.07131	$0.08459	$0.07143	$0.06920
15	SULPHER	$0.06181	$0.06597	$0.07711	$0.08636	$0.06273	$0.05756	$0.05672	$0.05560	$0.05947	$0.06396	$0.06943	$0.05996	$0.06302
16	TRICO	$0.06318	$0.06758	$0.07148	$0.07058	$0.06396	$0.05635	$0.05452	$0.05388	$0.05744	$0.06301	$0.06824	$0.06044	$0.06125
17	AEPCO CLASS A	$0.06551	$0.07085	$0.07790	$0.07993	$0.06621	$0.05868	$0.05606	$0.05538	$0.06033	$0.06670	$0.07377	$0.06389	$0.06461

Arizona Electric Power Cooperative, Inc.

ANZA ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	6,468	6,132	9,936	11,832	10,716	9,036	5,592	6,564	9,156	7,440	7,596	6,408	96,876
3	kW - Current Year	6,744	7,368	5,988	5,424	5,760	8,436	10,524	9,396	8,400	6,804	7,164	7,404	89,412
4	kW - 12 Month Average	8,096	8,199	7,870	7,336	6,923	6,873	7,284	7,520	7,457	7,404	7,368	7,451	89,781
5	ARM Load Ratio Share	20.30%	20.73%	20.90%	20.53%	19.96%	19.04%	19.27%	18.73%	17.89%	17.60%	17.53%	17.53%	19.11%
6	KWH - TOTAL	4,257,329	4,142,808	4,173,822	3,770,215	3,927,846	4,098,396	4,852,867	5,136,535	4,269,366	3,812,046	4,034,970	4,770,882	51,247,082
7	KWH - BASE RESOURCES	4,197,622	4,067,797	3,173,855	2,633,137	3,584,926	3,742,609	4,395,121	4,686,541	4,162,288	3,755,926	3,795,186	4,765,323	46,960,331
8	KWH - OTHER EXISTING RESOURCES	59,707	75,011	999,967	1,137,078	342,920	355,787	457,746	449,994	107,078	56,120	239,784	5,559	4,286,751
9														
10	**PRESENT RATES w/ PPFCA SYNCHRONIZED**													
11	Fixed Demand Charge	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	
12	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
13	Base Resource Energy Charge	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	
14	Other Existing Resources Energy Charge	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	
15	Base PPFAC Adjustor Accrual	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	
16	Other PPFAC Adjustor Acrrual	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	
17														
18	**PRESENT REVENUES w/ PPFCA SYNCH.**													
19	Fixed / O&M Charge Revenue	$139,534	$142,501	$143,677	$141,133	$137,212	$130,867	$132,454	$128,713	$122,994	$120,942	$120,505	$120,495	$1,581,026
20	Base Energy Charge Revenue	131,470	127,403	99,405	82,470	112,280	117,219	137,655	146,782	130,363	117,636	118,865	149,250	1,470,798
21	Base Energy Charge Revenue	3,164	3,976	52,998	60,265	18,175	18,857	24,261	23,850	5,675	2,974	12,709	295	227,198
22	Total Present Base Rate Revenue	$274,168	$273,880	$296,080	$283,868	$267,667	$266,942	$294,370	$299,345	$259,032	$241,552	$252,078	$270,039	$3,279,021
23	Base PPFAC Accrual	11,792	11,427	8,916	7,397	10,071	10,514	12,347	13,165	11,693	10,551	10,661	13,387	131,919
24	Other PPFAC Accrual	(1,124)	(1,412)	(18,825)	(21,406)	(6,456)	(6,698)	(8,617)	(8,471)	(2,016)	(1,056)	(4,514)	(105)	(80,701)
25	Total Present Revenue	$284,835	$283,895	$286,171	$269,858	$271,282	$270,757	$298,099	$304,039	$268,709	$251,047	$258,226	$283,321	$3,330,240
26														
27	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
28	Fixed Demand Charge	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	
29	O&M Demand Charge	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	
30	Base Resource Energy Charge	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
31	Other Existing Resources Energy Charge	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
32	Base and Other PPFAC Adjustor	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
33														
34	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
35	Fixed Demand Charge Revenue	$56,962	$58,173	$58,653	$57,615	$56,014	$53,424	$54,072	$52,544	$50,210	$49,372	$49,194	$49,190	$645,423
36	O&M Demand Charge Revenue	93,010	94,988	95,772	94,076	91,463	87,233	88,291	85,797	81,986	80,618	80,326	80,319	1,053,880
37	Base Resource Energy Revenue	122,624	118,831	92,717	76,921	104,725	109,331	128,393	136,906	121,591	109,721	110,867	139,208	1,371,835
38	Other Existing Resources Energy Revenue	2,863	3,597	47,945	54,519	16,442	17,059	21,947	21,576	5,134	2,691	11,497	267	205,534
39	Total Proposed Base Rate Revenue	$275,458	$275,589	$295,087	$283,130	$268,644	$267,047	$292,703	$296,824	$258,921	$242,401	$251,884	$268,983	$3,276,672
40	Base and Other PPFAC Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Total Proposed Revenue	$275,458	$275,589	$295,087	$283,130	$268,644	$267,047	$292,703	$296,824	$258,921	$242,401	$251,884	$268,983	$3,276,672
42														
43	**PROPOSED REVENUE CHANGES**													
44	Change in Fixed and Demand Revenue	$10,439	$10,661	$10,749	$10,558	$10,265	$9,790	$9,909	$9,629	$9,201	$9,048	$9,015	$9,014	$118,277
45	Change in Energy Charge Revenue	(9,148)	(8,951)	(11,742)	(11,295)	(9,288)	(9,685)	(11,575)	(12,150)	(9,313)	(8,199)	(9,210)	(10,070)	(120,626)
46	Change in Base Rate Revenue	$1,291	$1,709	($993)	($737)	$977	$105	($1,666)	($2,521)	($111)	$849	($195)	($1,056)	($2,349)
47	Change in PPFCA Revenue	(10,668)	(10,015)	9,909	14,009	(3,615)	(3,816)	(3,729)	(4,694)	(9,677)	(9,495)	(6,147)	(13,282)	80,701
48	Change in Total Revenue	($9,377)	($8,306)	$8,916	$13,272	($2,638)	($3,711)	($5,396)	($7,215)	($9,788)	($8,645)	($6,342)	($14,338)	($53,567)
49	Percentage Change in Base Rate Revenue	0.47%	0.62%	-0.34%	-0.26%	0.37%	0.04%	-0.57%	-0.84%	-0.04%	0.35%	-0.08%	-0.39%	-0.07%
50	Percentage Change in Total Revenue	-3.29%	-2.93%	3.12%	4.92%	-0.97%	-1.37%	-1.81%	-2.37%	-3.64%	-3.44%	-2.46%	-5.06%	-1.61%

Arizona Electric Power Cooperative, Inc.

DUNCAN ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	BILLING DETERMINANTS													
2	kW - Previous Year	3,100	5,640	6,660	6,020	6,520	3,720	4,520	3,320	4,520	4,320	4,180	3,260	55,780
3	kW - Current Year	4,304	5,306	3,854	3,808	5,380	7,406	6,954	6,748	6,084	4,422	3,588	4,132	61,986
4	kW - 12 Month Average	4,749	4,721	4,487	4,303	4,208	4,515	4,718	5,003	5,134	5,142	5,093	5,166	57,237
5	ARM Load Ratio Share	11.91%	11.94%	11.92%	12.04%	12.13%	12.51%	12.48%	12.46%	12.32%	12.22%	12.12%	12.15%	12.18%
6	KWH - TOTAL	2,283,326	2,048,024	2,011,360	2,160,532	2,387,618	3,278,746	3,616,574	3,308,787	2,462,224	1,863,676	1,835,082	2,360,283	29,616,232
7	KWH - BASE RESOURCES	2,251,302	2,010,942	1,529,477	1,508,927	2,179,167	2,994,114	3,275,441	3,018,916	2,400,470	1,836,239	1,726,029	2,357,533	27,088,557
8	KWH - OTHER EXISTING RESOURCES	32,024	37,082	481,883	651,605	208,451	284,632	341,133	289,871	61,754	27,437	109,053	2,750	2,527,675
9														
10	PRESENT RATES w/ PPFCA SYNCHRONIZED													
11	Fixed Demand Charge	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	
12	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
13	Base Resource Energy Charge	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	
14	Other Existing Resources Energy Charge	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	
15	Base PPFAC Adjustor Accrual	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	
16	Other PPFAC Adjustor Acrrual	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	
17														
18	PRESENT REVENUES w/ PPFCA SYNCH.													
19	Fixed / O&M Charge Revenue	$81,843	$82,050	$81,916	$82,776	$83,395	$85,965	$85,787	$85,637	$84,674	$83,996	$83,294	$83,534	$1,004,868
20	Base Energy Charge Revenue	70,511	62,983	47,903	47,260	68,252	93,776	102,587	94,552	75,183	57,511	54,059	73,838	848,414
21	Other Energy Charge Revenue	1,697	1,965	25,540	34,535	11,048	15,085	18,080	15,363	3,273	1,454	5,780	146	133,967
22	Total Present Base Rate Revenue	$154,051	$146,998	$155,359	$164,571	$162,694	$194,827	$206,454	$195,553	$163,129	$142,961	$143,133	$157,518	$1,987,248
23	Base PPFAC Accrual	6,324	5,649	4,297	4,239	6,122	8,411	9,201	8,481	6,743	5,158	4,849	6,623	76,096
24	Other PPFAC Accrual	(603)	(698)	(9,072)	(12,267)	(3,924)	(5,358)	(6,422)	(5,457)	(1,163)	(517)	(2,053)	(52)	(47,585)
25	Total Present Revenue	$159,772	$151,949	$150,584	$156,543	$164,892	$197,879	$209,233	$198,577	$168,710	$147,603	$145,929	$164,089	$2,015,759
26														
27	PROPOSED RATES - Monthly Fixed and O&M Facility Charge													
28	Fixed Demand Charge	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	
29	O&M Demand Charge	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	
30	Base Resource Energy Charge	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
31	Other Existing Resources Energy Charge	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
32	Base and Other PPFAC Adjustor	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
33														
34	PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge													
35	Fixed Demand Charge Revenue	$33,411	$33,495	$33,441	$33,792	$34,044	$35,094	$35,021	$34,960	$34,566	$34,290	$34,003	$34,101	$410,218
36	O&M Demand Charge Revenue	54,555	54,693	54,604	55,177	55,589	57,303	57,184	57,084	56,442	55,990	55,522	55,682	669,824
37	Base Resource Energy Revenue	65,766	58,745	44,680	44,080	63,659	87,466	95,684	88,190	70,124	53,641	50,422	68,870	791,328
38	Other Existing Resources Energy Revenue	1,535	1,778	23,105	31,242	9,994	13,647	16,356	13,898	2,961	1,316	5,229	132	121,193
39	Total Proposed Base Rate Revenue	$155,267	$148,711	$155,829	$164,291	$163,287	$193,510	$204,245	$194,133	$164,093	$145,237	$145,176	$158,785	$1,992,563
40	Base and Other PPFAC Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Total Proposed Revenue	$155,267	$148,711	$155,829	$164,291	$163,287	$193,510	$204,245	$194,133	$164,093	$145,237	$145,176	$158,785	$1,992,563
42														
43	PROPOSED REVENUE CHANGES													
44	Change in Fixed and Demand Revenue	$6,123	$6,138	$6,128	$6,193	$6,239	$6,431	$6,418	$6,407	$6,334	$6,284	$6,231	$6,249	$75,174
45	Change in Energy Charge Revenue	(4,906)	(4,425)	(5,658)	(6,473)	(5,646)	(7,748)	(8,627)	(7,827)	(5,371)	(4,008)	(4,188)	(4,982)	(69,859)
46	Change in Base Rate Revenue	$1,217	$1,713	$470	($280)	$593	($1,317)	($2,209)	($1,420)	$964	$2,275	$2,043	$1,267	$5,315
47	Change in PPFCA Revenue	(5,721)	(4,951)	4,775	8,028	(2,197)	(3,053)	(2,779)	(3,024)	(5,581)	(4,642)	(2,796)	(6,571)	47,585
48	Change in Total Revenue	($4,505)	($3,238)	$5,245	$7,748	($1,604)	($4,370)	($4,988)	($4,444)	($4,617)	($2,366)	($753)	($5,304)	($23,196)
49	Percentage Change in Base Rate Revenue	0.79%	1.17%	0.30%	-0.17%	0.36%	-0.68%	-1.07%	-0.73%	0.59%	1.59%	1.43%	0.80%	0.27%
50	Percentage Change in Total Revenue	-2.82%	-2.13%	3.48%	4.95%	-0.97%	-2.21%	-2.38%	-2.24%	-2.74%	-1.60%	-0.52%	-3.23%	-1.15%

Arizona Electric Power Cooperative, Inc.

GRAHAM ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	21,235	29,349	40,099	39,125	36,733	30,341	27,052	18,498	21,918	20,119	19,731	19,458	323,658
3	kW - Current Year	22,019	24,442	24,082	24,682	30,252	44,283	40,089	40,545	39,290	25,523	20,126	23,313	358,646
4	kW - 12 Month Average	27,037	26,628	25,293	24,090	23,550	24,711	25,798	27,635	29,083	29,533	29,566	29,887	322,810
5	ARM Load Ratio Share	67.79%	67.33%	67.18%	67.42%	67.90%	68.45%	68.25%	68.82%	69.79%	70.18%	70.35%	70.32%	68.71%
6	KWH - TOTAL	11,984,085	10,179,691	12,037,507	13,307,005	13,805,610	19,434,851	21,429,924	20,180,101	15,077,946	11,386,313	10,850,200	13,040,234	172,713,467
7	KWH - BASE RESOURCES	11,816,010	9,995,374	9,153,553	9,293,680	12,600,313	17,747,686	19,408,552	18,412,194	14,699,784	11,218,688	10,205,411	13,025,040	157,576,285
8	KWH - OTHER EXISTING RESOURCES	168,075	184,317	2,883,954	4,013,325	1,205,297	1,687,165	2,021,372	1,767,907	378,162	167,625	644,789	15,194	15,137,182
9														
10	**PRESENT RATES w/ PPFCA SYNCHRONIZED**													
11	Fixed Demand Charge	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	$273,334	
12	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
13	Base Resource Energy Charge	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	$0.03132	
14	Other Existing Resources Energy Charge	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	$0.05300	
15	Base PPFAC Adjustor Accrual	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	$0.00281	
16	Other PPFAC Adjustor Acrrual	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	($0.01883)	
17														
18	**PRESENT REVENUES w/ PPFCA SYNCH.**													
19	Fixed / O&M Charge Revenue	$465,976	$462,802	$461,760	$463,444	$466,745	$470,521	$469,112	$473,002	$479,684	$482,414	$483,554	$483,324	$5,662,338
20	Base Energy Charge Revenue	370,077	313,055	286,689	291,078	394,642	555,858	607,876	576,670	460,397	351,369	319,633	407,944	4,935,289
21	Other Energy Charge Revenue	8,908	9,769	152,850	212,706	63,881	89,420	107,133	93,699	20,043	8,884	34,174	805	802,271
22	Total Present Base Rate Revenue	$844,962	$785,626	$901,298	$967,228	$925,268	$1,115,798	$1,184,120	$1,143,371	$960,124	$842,668	$837,361	$892,073	$11,399,898
23	Base PPFAC Accrual	33,193	28,079	25,714	26,107	35,396	49,856	54,522	51,723	41,294	31,515	28,669	36,589	442,657
24	Other PPFAC Accrual	(3,164)	(3,470)	(54,292)	(75,554)	(22,691)	(31,762)	(38,054)	(33,282)	(7,119)	(3,156)	(12,139)	(286)	(284,967)
25	Total Present Revenue	$874,991	$810,234	$872,720	$917,782	$937,974	$1,133,892	$1,200,588	$1,161,812	$994,299	$871,027	$853,892	$928,376	$11,557,588
26														
27	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
28	Fixed Demand Charge	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	$280,598	
29	O&M Demand Charge	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	$458,175	
30	Base Resource Energy Charge	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	$0.02921	
31	Other Existing Resources Energy Charge	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	$0.04795	
32	Base and Other PPFAC Adjustor Charge	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
33														
34	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
35	Fixed Demand Charge Revenue	$190,226	$188,930	$188,504	$189,192	$190,540	$192,081	$191,506	$193,094	$195,822	$196,936	$197,402	$197,307	$2,311,539
36	O&M Demand Charge Revenue	310,610	308,494	307,800	308,922	311,123	313,640	312,700	315,294	319,748	321,568	322,327	322,174	3,774,401
37	Base Resource Energy Revenue	345,177	291,991	267,399	271,493	368,088	518,457	566,975	537,869	429,419	327,727	298,127	380,496	4,603,219
38	Other Existing Resources Energy Revenue	8,059	8,837	138,275	192,424	57,790	80,893	96,917	84,765	18,131	8,037	30,915	728	725,773
39	Total Proposed Base Rate Revenue	$854,072	$798,253	$901,978	$962,032	$927,541	$1,105,070	$1,168,099	$1,131,021	$963,121	$854,268	$848,771	$900,705	$11,414,931
40	Base and Other PPFAC Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Total Proposed Revenue	$854,072	$798,253	$901,978	$962,032	$927,541	$1,105,070	$1,168,099	$1,131,021	$963,121	$854,268	$848,771	$900,705	$11,414,931
42														
43	**PROPOSED REVENUE CHANGES**													
44	Change in Fixed and Demand Revenue	$34,860	$34,622	$34,544	$34,670	$34,917	$35,200	$35,094	$35,385	$35,885	$36,090	$36,175	$36,158	$423,601
45	Change in Energy Charge Revenue	(25,750)	(21,995)	(33,864)	(39,867)	(32,645)	(45,927)	(51,116)	(47,736)	(32,889)	(24,489)	(24,765)	(27,525)	(408,568)
46	Change in Base Rate Revenue	$9,110	$12,627	$680	($5,197)	$2,273	($10,727)	($16,022)	($12,350)	$2,996	$11,601	$11,410	$8,632	$15,033
47	Change in PPFCA Revenue	(30,029)	(24,609)	28,579	49,446	(12,706)	(18,094)	(16,468)	(18,441)	(34,175)	(28,359)	(16,530)	(36,303)	284,967
48	Change in Total Revenue	($20,919)	($11,982)	$29,259	$44,249	($10,433)	($28,821)	($32,490)	($30,791)	($31,178)	($16,759)	($5,120)	($27,671)	($142,657)
49	Percentage Change in Base Rate Revenue	1.08%	1.61%	0.08%	-0.54%	0.25%	-0.96%	-1.35%	-1.08%	0.31%	1.38%	1.36%	0.97%	0.13%
50	Percentage Change in Total Revenue	-2.39%	-1.48%	3.35%	4.82%	-1.11%	-2.54%	-2.71%	-2.65%	-3.14%	-1.92%	-0.60%	-2.98%	-1.23%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	87,362	96,045	81,470	101,945	127,494	175,484	187,399	197,842	179,554	134,569	77,596	86,839	1,533,599
3	KWH - TOTAL	54,728,000	45,968,000	38,932,000	38,255,000	53,012,000	67,971,000	80,958,000	83,569,000	66,876,000	53,714,000	40,895,000	53,552,000	678,430,000
4	KWH - BASE RESOURCES	54,728,000	45,960,000	38,687,000	38,254,000	53,012,000	67,970,000	80,900,000	83,541,000	66,876,000	53,714,000	40,894,000	53,552,000	678,088,000
5	KWH - OTHER EXISTING RESOURCES	0	8,000	245,000	1,000	0	1,000	58,000	28,000	0	0	1,000	0	342,000
6														
7	**PRESENT RATES w/ PPFCA SYNCHRONIZED**													
8	Fixed Demand Charge	$835,756	$835,756	$835,756	$835,756	$835,756	$835,756	$835,756	$835,756	$835,756	$835,756	$835,756	$835,756	
9	O&M Demand Charge	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	
10	Base Resource Energy Charge	$0.03191	$0.03191	$0.03191	$0.03191	$0.03191	$0.03191	$0.03191	$0.03191	$0.03191	$0.03191	$0.03191	$0.03191	
11	Other Existing Resources Energy Charge	$0.05852	$0.05852	$0.05852	$0.05852	$0.05852	$0.05852	$0.05852	$0.05852	$0.05852	$0.05852	$0.05852	$0.05852	
12	Base PPFAC Adjustor Accrual	$0.00473	$0.00473	$0.00473	$0.00473	$0.00473	$0.00473	$0.00473	$0.00473	$0.00473	$0.00473	$0.00473	$0.00473	
13	Other PPFAC Adjustor Acrrual	($0.01706)	($0.01706)	($0.01706)	($0.01706)	($0.01706)	($0.01706)	($0.01706)	($0.01706)	($0.01706)	($0.01706)	($0.01706)	($0.01706)	
14														
15	**PRESENT REVENUES w/ PPFCA SYNCH.**													
16	Fixed / O&M Charge Revenue	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$2,110,638	$25,327,656
17	Base Energy Charge Revenue	1,746,370	1,466,584	1,234,502	1,220,685	1,691,613	2,168,923	2,581,519	2,665,793	2,134,013	1,714,014	1,304,928	1,708,844	21,637,788
18	Other Energy Charge Revenue	0	468	14,337	59	0	59	3,394	1,639	0	0	59	0	20,014
19	Total Present Base Rate Revenue	$3,857,008	$3,577,690	$3,359,478	$3,331,382	$3,802,251	$4,279,619	$4,695,551	$4,778,070	$4,244,651	$3,824,652	$3,415,624	$3,819,482	$46,985,458
20	Base PPFAC Accrual	258684	217240	182863	180816	250573	321276	382392	394875	316105	253891	193295	253126	3205136
21	Other PPFAC Accrual	0	(136)	(4,179)	(17)	0	(17)	(989)	(478)	0	0	(17)	0	(5,834)
22	Total Present Revenue	$4,115,693	$3,794,794	$3,538,161	$3,512,181	$4,052,824	$4,600,878	$5,076,954	$5,172,468	$4,560,756	$4,078,543	$3,608,902	$4,072,608	$50,184,760
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	
26	O&M Demand Charge	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	$1,419,059	
27	Base Resource Energy Charge	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	$0.02894	
28	Other Existing Resources Energy Charge	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	$0.05437	
29	Base and Other PPFAC Adjustor Charge	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
30														
31	**PROPOSED REVENUES**													
32	Fixed Demand Charge Revenue	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$856,355	$10,276,259
33	O&M Demand Charge Revenue	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	1,419,059	17,028,710
34	Base Resource Energy Revenue	1,584,075	1,330,290	1,119,776	1,107,243	1,534,406	1,967,358	2,341,611	2,418,053	1,935,693	1,554,725	1,183,657	1,550,036	19,626,925
35	Other Existing Resources Energy Revenue	0	435	13,320	54	0	54	3,153	1,522	0	0	54	0	18,594
36	Total Proposed Base Rate Revenue	$3,859,489	$3,606,139	$3,408,511	$3,382,712	$3,809,820	$4,242,827	$4,620,178	$4,694,990	$4,211,107	$3,830,139	$3,459,125	$3,825,450	$46,950,488
37	Base and Other PPFAC Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Total Proposed Revenue	$3,859,489	$3,606,139	$3,408,511	$3,382,712	$3,809,820	$4,242,827	$4,620,178	$4,694,990	$4,211,107	$3,830,139	$3,459,125	$3,825,450	$46,950,488
39														
40	**PROPOSED REVENUE CHANGES**													
41	Change in Fixed and Demand Revenue	$164,776	$164,776	$164,776	$164,776	$164,776	$164,776	$164,776	$164,776	$164,776	$164,776	$164,776	$164,776	$1,977,313
42	Change in Energy Charge Revenue	(162,295)	(136,327)	(115,743)	(113,446)	(157,207)	(201,568)	(240,149)	(247,856)	(198,320)	(159,288)	(121,275)	(158,808)	(2,012,283)
43	Change in Base Rate Revenue	$2,481	$28,449	$49,033	$51,330	$7,570	($36,792)	($75,373)	($83,080)	($33,544)	$5,488	$43,501	$5,968	($34,970)
44	Change in PPFCA Revenue	(258,684)	(217,104)	(178,683)	(180,799)	(250,573)	(321,259)	(381,403)	(394,398)	(316,105)	(253,891)	(193,278)	(253,126)	(3,199,302)
45	Change in Total Revenue	($256,204)	($188,655)	($129,650)	($129,469)	($243,004)	($358,051)	($456,776)	($477,478)	($349,649)	($248,404)	($149,777)	($247,157)	($3,234,272)
46	Percentage Change in Base Rate Revenue	0.06%	0.80%	1.46%	1.54%	0.20%	-0.86%	-1.61%	-1.74%	-0.79%	0.14%	1.27%	0.16%	-0.07%
47	Percentage Change in Total Revenue	-6.23%	-4.97%	-3.66%	-3.69%	-6.00%	-7.78%	-9.00%	-9.23%	-7.67%	-6.09%	-4.15%	-6.07%	-6.44%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	119,327	151,864	111,504	125,854	155,264	202,467	202,194	204,733	190,763	120,205	102,894	124,156	1,811,225
3	KWH - TOTAL	62,152,000	55,094,000	42,355,000	35,372,000	60,460,000	71,518,000	73,729,000	76,858,000	66,969,000	58,272,000	50,347,000	66,088,000	719,214,000
4	KWH - BASE RESOURCES	62,145,000	55,075,000	42,226,000	35,359,000	60,437,000	71,515,000	73,721,000	76,858,000	66,964,000	58,271,000	50,321,000	65,976,000	718,868,000
5	KWH - OTHER EXISTING RESOURCES	7,000	19,000	129,000	13,000	23,000	3,000	8,000	0	5,000	1,000	26,000	112,000	346,000
6														
7	**PRESENT RATES w/ PPFCA SYNCHRONIZED**													
8	Fixed Demand Charge	$740,041	$740,041	$740,041	$740,041	$740,041	$740,041	$740,041	$740,041	$740,041	$740,041	$740,041	$740,041	
9	O&M Demand Charge	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	
10	Base Resource Energy Charge	$0.03205	$0.03205	$0.03205	$0.03205	$0.03205	$0.03205	$0.03205	$0.03205	$0.03205	$0.03205	$0.03205	$0.03205	
11	Other Existing Resources Energy Charge	$0.05742	$0.05742	$0.05742	$0.05742	$0.05742	$0.05742	$0.05742	$0.05742	$0.05742	$0.05742	$0.05742	$0.05742	
12	Base PPFAC Adjustor Accrual	$0.00266	$0.00266	$0.00266	$0.00266	$0.00266	$0.00266	$0.00266	$0.00266	$0.00266	$0.00266	$0.00266	$0.00266	
13	Other PPFAC Adjustor Acrrual	$0.03056	$0.03056	$0.03056	$0.03056	$0.03056	$0.03056	$0.03056	$0.03056	$0.03056	$0.03056	$0.03056	$0.03056	
14														
15	**PRESENT REVENUES w/ PPFCA SYNCH.**													
16	Fixed / O&M Charge Revenue	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$1,868,917	$22,427,004
17	Base Energy Charge Revenue	1,991,747	1,765,154	1,353,343	1,133,256	1,937,006	2,292,056	2,362,758	2,463,299	2,146,196	1,867,586	1,612,788	2,114,531	23,039,719
18	Other Energy Charge Revenue	402	1,091	7,407	746	1,321	172	459	0	287	57	1,493	6,431	19,867
19	Total Present Base Rate Revenue	$3,861,066	$3,635,162	$3,229,667	$3,002,919	$3,807,244	$4,161,145	$4,232,134	$4,332,216	$4,015,400	$3,736,560	$3,483,198	$3,989,879	$45,486,591
20	Base PPFAC Accrual	165,457	146,634	112,424	94,141	160,910	190,405	196,278	204,630	178,288	155,143	133,977	175,657	1,913,945
21	Other PPFAC Accrual	214	581	3,943	397	703	92	245	0	153	31	795	3,423	10,575
22	Total Present Revenue	$4,026,738	$3,782,376	$3,346,035	$3,097,458	$3,968,857	$4,351,641	$4,428,657	$4,536,846	$4,193,841	$3,891,734	$3,617,969	$4,168,959	$47,411,111
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	
26	O&M Demand Charge	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	$1,256,541	
27	Base Resource Energy Charge	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	$0.02938	
28	Other Existing Resources Energy Charge	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	$0.05109	
29	Base and Other PPFAC Adjustor Charge	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
30														
31	**PROPOSED REVENUES**													
32	Fixed Demand Charge Revenue	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$758,281	$9,099,369
33	O&M Demand Charge Revenue	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	1,256,541	15,078,494
34	Base Resource Energy Revenue	1,825,977	1,618,243	1,240,707	1,038,937	1,775,792	2,101,292	2,166,109	2,258,282	1,967,572	1,712,149	1,478,558	1,938,542	21,122,159
35	Other Existing Resources Energy Revenue	358	971	6,591	664	1,175	153	409	0	255	51	1,328	5,723	17,678
36	Total Proposed Base Rate Revenue	$3,841,157	$3,634,035	$3,262,120	$3,054,423	$3,791,789	$4,116,267	$4,181,340	$4,273,104	$3,982,649	$3,727,022	$3,494,709	$3,959,086	$45,317,701
37	Base and Other PPFAC Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Total Proposed Revenue	$3,841,157	$3,634,035	$3,262,120	$3,054,423	$3,791,789	$4,116,267	$4,181,340	$4,273,104	$3,982,649	$3,727,022	$3,494,709	$3,959,086	$45,317,701
39														
40	**PROPOSED REVENUE CHANGES**													
41	Change in Fixed and Demand Revenue	$145,905	$145,905	$145,905	$145,905	$145,905	$145,905	$145,905	$145,905	$145,905	$145,905	$145,905	$145,905	$1,750,859
42	Change in Energy Charge Revenue	(165,814)	(147,031)	(113,453)	(94,401)	(161,359)	(190,783)	(196,699)	(205,017)	(178,656)	(155,443)	(134,394)	(176,698)	(1,919,749)
43	Change in Base Rate Revenue	($19,909)	($1,126)	$32,452	$51,504	($15,455)	($44,878)	($50,794)	($59,112)	($32,751)	($9,538)	$11,511	($30,793)	($168,889)
44	Change in PPFCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
45	Change in Total Revenue	($185,581)	($148,341)	($83,915)	($43,035)	($177,068)	($235,375)	($247,317)	($263,742)	($211,192)	($164,711)	($123,261)	($209,873)	($168,889)
46	Percentage Change in Base Rate Revenue	-0.52%	-0.03%	1.00%	1.72%	-0.41%	-1.08%	-1.20%	-1.36%	-0.82%	-0.26%	0.33%	-0.77%	-0.37%
47	Percentage Change in Total Revenue	-4.61%	-3.92%	-2.51%	-1.39%	-4.46%	-5.41%	-5.58%	-5.81%	-5.04%	-4.23%	-3.41%	-5.03%	-0.36%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**BILLING DETERMINANTS**													
2	KW	93,162	109,942	78,252	93,298	117,654	173,678	170,512	169,634	162,034	124,318	77,608	96,230	1,466,322
3	KWH - TOTAL	49,056,197	44,022,811	42,924,616	45,454,856	51,780,343	71,393,709	77,854,329	81,298,148	65,194,146	51,719,720	42,828,323	53,071,837	676,599,035
4	KWH - BASE RESOURCES	45,133,083	38,207,639	27,237,756	24,614,424	37,461,680	46,622,530	50,598,919	51,339,503	47,940,460	41,414,455	38,368,477	49,937,693	498,876,619
5	KWH - OTHER EXISTING RESOURCES	3,923,114	5,815,172	15,686,860	20,840,432	14,318,663	24,771,179	27,255,410	29,958,645	17,253,686	10,305,265	4,459,846	3,134,144	177,722,416
6														
7	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
8	Fixed Demand Charge	$710,367	$710,367	$710,367	$710,367	$710,367	$710,367	$710,367	$710,367	$710,367	$710,367	$710,367	$710,367	
9	O&M Demand Charge	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	
10	Base Resource Energy Charge	$0.03214	$0.03214	$0.03214	$0.03214	$0.03214	$0.03214	$0.03214	$0.03214	$0.03214	$0.03214	$0.03214	$0.03214	
11	Other Existing Resources Energy Charge	$0.05747	$0.05747	$0.05747	$0.05747	$0.05747	$0.05747	$0.05747	$0.05747	$0.05747	$0.05747	$0.05747	$0.05747	
12	Base PPFAC Adjustor Accrual	$0.00140	$0.00140	$0.00140	$0.00140	$0.00140	$0.00140	$0.00140	$0.00140	$0.00140	$0.00140	$0.00140	$0.00140	
13	Other PPFAC Adjustor Acrrual	($0.02372)	($0.02372)	($0.02372)	($0.02372)	($0.02372)	($0.02372)	($0.02372)	($0.02372)	($0.02372)	($0.02372)	($0.02372)	($0.02372)	
14														
15	**PRESENT REVENUES w/ PPFCA SYNCH.**													
16	Fixed / O&M Charge Revenue	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$1,474,832	$17,697,986
17	Base Energy Charge Revenue	1,450,577	1,227,994	875,421	791,108	1,204,018	1,498,448	1,626,249	1,650,052	1,540,806	1,331,061	1,233,163	1,604,997	16,033,895
18	Other Energy Charge Revenue	225,461	334,198	901,524	1,197,700	822,894	1,423,600	1,566,368	1,721,723	991,569	592,244	256,307	180,119	10,213,707
19	Total Present Base Rate Revenue	$3,150,871	$3,037,024	$3,251,778	$3,463,639	$3,501,744	$4,396,880	$4,667,450	$4,846,607	$4,007,208	$3,398,136	$2,964,302	$3,259,949	$43,945,588
20	Base PPFAC Accrual	62,961	53,300	37,997	34,337	52,259	65,038	70,586	71,619	66,877	57,773	53,524	69,663	695,933
21	Other PPFAC Accrual	(93,068)	(137,953)	(372,139)	(494,397)	(339,681)	(587,646)	(646,580)	(710,708)	(409,309)	(244,472)	(105,801)	(74,351)	(4,216,106)
22	Total Present Revenue	$3,120,764	$2,952,370	$2,917,635	$3,003,579	$3,214,322	$3,874,272	$4,091,456	$4,207,517	$3,664,776	$3,211,438	$2,912,026	$3,255,261	$40,425,415
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	
26	O&M Demand Charge	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	$859,840	
27	Base Resource Energy Charge	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	$0.02947	
28	Other Existing Resources Energy Charge	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	$0.04219	
29	Base and Other PPFAC Adjustor Charge	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
30														
31	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
32	Fixed Demand Charge Revenue	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$743,828	$8,925,935
33	O&M Demand Charge Revenue	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	859,840	10,318,076
34	Base Resource Energy Revenue	1,330,152	1,126,047	802,745	725,431	1,104,062	1,374,048	1,491,240	1,513,066	1,412,890	1,220,557	1,130,787	1,471,752	14,702,775
35	Other Existing Resources Energy Revenue	165,520	245,347	661,842	879,276	604,117	1,045,118	1,149,930	1,263,981	727,948	434,788	188,165	132,232	7,498,264
36	Total Proposed Base Rate Revenue	$3,099,339	$2,975,061	$3,068,255	$3,208,374	$3,311,846	$4,022,834	$4,244,837	$4,380,715	$3,744,506	$3,259,013	$2,922,619	$3,207,652	$41,445,050
37	Base and Other PPFAC Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Total Proposed Revenue	$3,099,339	$2,975,061	$3,068,255	$3,208,374	$3,311,846	$4,022,834	$4,244,837	$4,380,715	$3,744,506	$3,259,013	$2,922,619	$3,207,652	$41,445,050
39														
40	**PROPOSED REVENUE CHANGES**													
41	Change in Fixed and Demand Revenue	$128,835	$128,835	$128,835	$128,835	$128,835	$128,835	$128,835	$128,835	$128,835	$128,835	$128,835	$128,835	$1,546,025
42	Change in Energy Charge Revenue	(180,367)	(190,798)	(312,358)	(384,101)	(318,733)	(502,882)	(551,449)	(594,728)	(391,538)	(267,959)	(170,519)	(181,132)	(4,046,563)
43	Change in Base Rate Revenue	($51,532)	($61,962)	($183,523)	($255,265)	($189,898)	($374,046)	($422,613)	($465,892)	($262,702)	($139,123)	($41,683)	($52,297)	($2,500,538)
44	Change in PPFCA Revenue	30,107	84,654	334,142	460,060	287,422	522,608	575,994	639,090	342,432	186,698	52,277	4,688	4,216,106
45	Change in Total Revenue	($21,425)	$22,691	$150,620	$204,795	$97,525	$148,561	$153,381	$173,197	$79,730	$47,575	$10,594	($47,609)	$1,019,635
46	Percentage Change in Base Rate Revenue	-1.64%	-2.04%	-5.64%	-7.37%	-5.42%	-8.51%	-9.05%	-9.61%	-6.56%	-4.09%	-1.41%	-1.60%	-5.69%
47	Percentage Change in Total Revenue	-0.69%	0.77%	5.16%	6.82%	3.03%	3.83%	3.75%	4.12%	2.18%	1.48%	0.36%	-1.46%	2.52%

Arizona Electric Power Cooperative, Inc.
CLASS A MEMBER ADJUSTED PRESENT WITH SYNCHRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**PRESENT REVENUES w/ PPFAC SYNCHRONIZED**													
2	TOTAL CLASS A													
3	Fixed / O&M Charge Revenue	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$6,141,740	$73,700,878
4	Base Energy Revenue	5,760,753	4,963,172	3,897,265	3,565,856	5,407,810	6,726,278	7,418,644	7,597,149	6,486,959	5,439,176	4,643,436	6,059,405	67,965,902
5	Other Energy Revenue	239,633	351,467	1,154,656	1,506,011	917,318	1,547,192	1,719,695	1,856,274	1,020,847	605,614	310,521	187,796	11,417,024
6	Total Present Base Rate Revenue	$12,142,126	$11,456,379	$11,193,660	$11,213,607	$12,466,868	$14,415,210	$15,280,079	$15,595,162	$13,649,545	$12,186,529	$11,095,697	$12,388,940	$153,083,804
7	Base PPFAC Accrual	538,412	462,329	372,210	347,038	515,331	645,499	725,325	744,493	620,999	514,032	424,974	555,045	6,465,687
8	Other PPFAC Accrual	(97,745)	(143,089)	(454,565)	(603,244)	(372,049)	(631,390)	(700,418)	(758,397)	(419,454)	(249,170)	(123,729)	(71,370)	(4,624,618)
9	Total Adjusted Present Revenue	$12,582,792	$11,775,618	$11,111,306	$10,957,401	$12,610,150	$14,429,320	$15,304,987	$15,581,259	$13,851,091	$12,451,392	$11,396,942	$12,872,615	$154,924,873
10														
11	**PROPOSED REVENUES**													
12	TOTAL CLASS A													
13	Demand Revenue	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$6,632,677	$79,592,128
14	Base Energy Revenue	5,273,771	4,544,146	3,568,024	3,264,104	4,950,733	6,157,952	6,790,012	6,952,367	5,937,290	4,978,521	4,252,418	5,548,903	62,218,242
15	Other Energy Revenue	178,334	260,965	891,078	1,158,180	689,518	1,156,924	1,288,712	1,385,742	754,430	446,882	237,188	139,082	8,587,036
16	Total Proposed Base Rate Revenue	$12,084,782	$11,437,788	$11,091,779	$11,054,961	$12,272,928	$13,947,554	$14,711,402	$14,970,787	$13,324,397	$12,058,081	$11,122,284	$12,320,662	$150,397,406
17	Base and Other PPFAC Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Total Adjusted Proposed Revenue	$12,084,782	$11,437,788	$11,091,779	$11,054,961	$12,272,928	$13,947,554	$14,711,402	$14,970,787	$13,324,397	$12,058,081	$11,122,284	$12,320,662	$150,397,406
19														
20	**PROPOSED REVENUE CHANGES**													
21	COLLECTIVE ALL REQUIREMENTS													
22	Fixed / O&M Charge Revenue	$51,421	$51,421	$51,421	$51,421	$51,421	$51,421	$51,421	$51,421	$51,421	$51,421	$51,421	$51,421	$617,053
23	Base Energy Revenue	(38,491)	(33,874)	(29,201)	(28,314)	(38,700)	(51,598)	(57,066)	(55,039)	(44,808)	(35,427)	(33,142)	(42,459)	(488,118)
24	Other Energy Revenue	(1,313)	(1,498)	(22,063)	(29,321)	(8,878)	(11,763)	(14,253)	(12,673)	(2,764)	(1,269)	(5,021)	(119)	(110,935)
25	Change in Base Rate Revenue	$11,617	$16,049	$156	($6,214)	$3,843	($11,939)	($19,897)	($16,292)	$3,849	$14,725	$13,258	$8,843	$17,999
26	Base and Other PPFAC Revenue	(46,418)	(39,575)	43,263	71,483	(18,518)	(24,962)	(22,977)	(26,158)	(49,432)	(42,496)	(25,473)	(56,156)	(237,419)
27	Total Revenue Change	($34,801)	($23,526)	$43,419	$65,269	($14,675)	($36,902)	($42,873)	($42,450)	($45,584)	($27,771)	($12,215)	($47,313)	($219,420)
28	Percent Change in Base Rate Revenue	0.11%	0.16%	0.00%	-0.06%	0.03%	-0.09%	-0.15%	-0.12%	0.03%	0.13%	0.13%	0.08%	0.01%
29	Percent Change in Total Revenue	-2.64%	-1.89%	3.32%	4.86%	-1.07%	-2.30%	-2.51%	-2.55%	-3.18%	-2.19%	-0.97%	-3.44%	-1.30%
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$439,516	$439,516	$439,516	$439,516	$439,516	$439,516	$439,516	$439,516	$439,516	$439,516	$439,516	$439,516	$5,274,198
33	Base Energy Revenue	(448,491)	(385,152)	(300,039)	(273,438)	(418,377)	(516,728)	(571,567)	(589,742)	(504,861)	(425,228)	(357,877)	(468,042)	(5,259,542)
34	Other Energy Revenue	(59,986)	(89,004)	(241,515)	(318,510)	(218,922)	(378,505)	(416,730)	(457,858)	(263,653)	(157,462)	(68,311)	(48,596)	(2,719,052)
35	Change in Base Rate Revenue	($68,961)	($34,640)	($102,038)	($152,432)	($197,783)	($455,717)	($548,780)	($608,084)	($328,997)	($143,173)	$13,329	($77,121)	($2,704,397)
36	Base and Other PPFAC Revenue	(394,248)	(279,665)	39,092	184,722	(124,764)	10,853	(1,931)	40,062	(152,113)	(222,367)	(275,772)	(427,518)	(1,603,650)
37	Total Revenue Change	($463,209)	($314,305)	($62,946)	$32,291	($322,547)	($444,864)	($550,711)	($568,022)	($481,111)	($365,540)	($262,444)	($504,640)	($4,308,047)
38	Percent Change in Base Rate Revenue	-0.63%	-0.34%	-1.04%	-1.56%	-1.78%	-3.55%	-4.04%	-4.36%	-2.68%	-1.31%	0.14%	-0.70%	-1.98%
39	Percent Change in Total Revenue	-4.11%	-2.98%	-0.64%	0.34%	-2.87%	-3.47%	-4.05%	-4.08%	-3.87%	-3.27%	-2.59%	-4.39%	-3.12%
40														
41	TOTAL CLASS A													
42	Fixed / O&M Charge Revenue	$490,938	$490,938	$490,938	$490,938	$490,938	$490,938	$490,938	$490,938	$490,938	$490,938	$490,938	$490,938	$5,891,250
43	Base Energy Revenue	(486,982)	(419,026)	(329,241)	(301,752)	(457,077)	(568,326)	(628,632)	(644,782)	(549,669)	(460,655)	(391,018)	(510,501)	(5,747,660)
44	Other Energy Revenue	(61,299)	(90,502)	(263,578)	(347,831)	(227,800)	(390,268)	(430,983)	(470,532)	(266,417)	(158,731)	(73,333)	(48,714)	(2,829,988)
45	Percent Change in Base Rate Revenue	($57,343)	($18,590)	($101,881)	($158,646)	($193,940)	($467,656)	($568,677)	($624,376)	($325,149)	($128,448)	$26,587	($68,278)	($2,686,398)
46	Base and Other PPFAC Revenue	(440,667)	(319,240)	82,355	256,206	(143,282)	(14,109)	(24,908)	13,904	(201,546)	(264,862)	(301,245)	(483,674)	(1,841,069)
47	Total Revenue Change	($498,010)	($337,830)	($19,526)	$97,560	($337,222)	($481,766)	($593,585)	($610,472)	($526,694)	($393,311)	($274,659)	($551,952)	($4,527,467)
48	Percent Change in Base Rate Revenue	-0.47%	-0.16%	-0.91%	-1.41%	-1.56%	-3.24%	-3.72%	-4.00%	-2.38%	-1.05%	0.24%	-0.55%	-1.75%
49	Percent Change in Total Revenue	-3.96%	-2.87%	-0.18%	0.89%	-2.67%	-3.34%	-3.88%	-3.92%	-3.80%	-3.16%	-2.41%	-4.29%	-2.92%

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

Line No.	Member	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
1	**AVERAGE COST PER KWH - PRESENT REVENUES**													
2	ANZA	$0.06690	$0.06853	$0.06856	$0.07158	$0.06907	$0.06606	$0.06143	$0.05919	$0.06294	$0.06586	$0.06400	$0.05939	$0.06498
3	DUNCAN	$0.06997	$0.07419	$0.07487	$0.07246	$0.06906	$0.06035	$0.05785	$0.06001	$0.06852	$0.07920	$0.07952	$0.06952	$0.06806
4	GRAHAM	$0.07301	$0.07959	$0.07250	$0.06897	$0.06794	$0.05834	$0.05602	$0.05757	$0.06594	$0.07650	$0.07870	$0.07119	$0.06692
5	MOHAVE	$0.07520	$0.08255	$0.09088	$0.09181	$0.07645	$0.06769	$0.06271	$0.06189	$0.06820	$0.07593	$0.08825	$0.07605	$0.07397
6	SULPHER	$0.06479	$0.06865	$0.07900	$0.08757	$0.06564	$0.06085	$0.06007	$0.05903	$0.06262	$0.06679	$0.07186	$0.06308	$0.06592
7	TRICO	$0.06362	$0.06706	$0.06797	$0.06608	$0.06208	$0.05427	$0.05255	$0.05175	$0.05621	$0.06209	$0.06799	$0.06134	$0.05975
8	AEPCO CLASS A	$0.06821	$0.07293	$0.07801	$0.07922	$0.06803	$0.06071	$0.05832	$0.05763	$0.06272	$0.06888	$0.07558	$0.06674	$0.06655
9														
10	**AVERAGE COST PER KWH - PROPOSED REVENUES**													
11	ANZA	$0.06470	$0.06652	$0.07070	$0.07510	$0.06839	$0.06516	$0.06032	$0.05779	$0.06065	$0.06359	$0.06243	$0.05638	$0.06394
12	DUNCAN	$0.06800	$0.07261	$0.07747	$0.07604	$0.06839	$0.05902	$0.05647	$0.05867	$0.06664	$0.07793	$0.07911	$0.06727	$0.06728
13	GRAHAM	$0.07127	$0.07842	$0.07493	$0.07230	$0.06719	$0.05686	$0.05451	$0.05605	$0.06388	$0.07503	$0.07823	$0.06907	$0.06609
14	MOHAVE	$0.07052	$0.07845	$0.08755	$0.08843	$0.07187	$0.06242	$0.05707	$0.05618	$0.06297	$0.07131	$0.08459	$0.07143	$0.06920
15	SULPHER	$0.06180	$0.06596	$0.07702	$0.08635	$0.06272	$0.05756	$0.05671	$0.05560	$0.05947	$0.06396	$0.06941	$0.05991	$0.06301
16	TRICO	$0.06318	$0.06758	$0.07148	$0.07058	$0.06396	$0.05635	$0.05452	$0.05388	$0.05744	$0.06301	$0.06824	$0.06044	$0.06125
17	AEPCO CLASS A	$0.06551	$0.07084	$0.07787	$0.07992	$0.06621	$0.05868	$0.05606	$0.05538	$0.06033	$0.06670	$0.07376	$0.06388	$0.06461

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

Line No.	RATE DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	TRICO ELECTRIC COOPERATIVE	COLLECTIVE ALL REQUIREMENTS MEMBERS
1	PRESENT MONTHLY CHARGES				
2	FIXED CHARGE - Per Month	$ 835,756	$ 740,041	$ 710,367	$ 273,334
3	O&M CHARGE - Per Month	1,274,882	1,128,876	764,465	414,019
4	TOTAL FIXED CHARGE PLUS O&M CHARGE	$2,110,638	$1,868,917	$1,474,832	$687,353
5	BASE RESOURCES ENERGY CHARGE - Per kWh	$0.03191	$0.03205	$0.03214	$0.03132
6	OTHER RESOURCEs ENERGY CHARGE - Per kWh	$0.05852	$0.05742	$0.05747	$0.05300
7	PPFAC-Base Resources Base - Per kWh	$0.03454	$0.03449	$0.03431	$0.03513
8	PPFAC-Other Resources Base - Per kWh	$0.06191	$0.06449	$0.08274	$0.07188
9	PPFAC-Fixed Fuel Costs Base - Per Month	$0	$0	$0	$0
10	AVERAGE ENERGY CHARGE	$0.03664	$0.03474	$0.03359	$0.03640
11					
12	PROPOSED MONTHLY CHARGES				
13	FIXED CHARGE	$856,355	$758,281	$743,828	$280,598
14	O&M CHARGE	$1,419,059	$1,256,541	$859,840	$458,175
15	TOTAL FIXED CHARGE PLUS O&M CHARGE	$2,275,414	$2,014,822	$1,603,668	$738,774
16	BASE RESOURCES ENERGY CHARGE - Per kWh	$0.02894	$0.02938	$0.02947	$0.02921
17	OTHER RESOURCES ENERGY CHARGE - Per kWh	$0.05437	$0.05109	$0.04219	$0.04795
18	PPFAC-Base Resources Base - Per kWh	$0.02894	$0.02938	$0.02947	$0.02921
19	PPFAC-Other Resources Base - Per kWh	$0.05437	$0.05109	$0.04219	$0.04795
20	PPFAC-Fixed Fuel Costs Base - Per Month	$542,273	$480,169	$569,977	$180,956
21	AVERAGE ENERGY CHARGE	$0.02896	$0.02939	$0.03281	$0.03083
22					
23	CHANGE IN MONTHLY CHARGES				
24	FIXED CHARGE	$20,599	$18,240	$33,461	$7,264
25	O&M CHARGE	$144,177	$127,665	$95,374	$44,157
26	TOTAL FIXED CHARGE PLUS O&M CHARGE	$164,776	$145,905	$128,835	$51,421
27	BASE ENERGY CHARGE	($0.00297)	($0.00267)	($0.00267)	($0.00211)
28	OTHER EXISTING RESOURCE ENERGY CHARGE	($0.00415)	($0.00633)	($0.01528)	($0.00505)
29	PPFAC-Base Resources Base - Per kWh	($0.00560)	($0.00511)	($0.00484)	($0.00592)
30	PPFAC-Other Resources Base - Per kWh	($0.00754)	($0.01340)	($0.04055)	($0.02393)
31	PPFAC-Fixed Fuel Costs Base - Per Month	$542,273	$480,169	$569,977	$180,956
32	AVERAGE ENERGY CHARGE	($0.00768)	($0.00535)	($0.00078)	($0.00556)

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

Arizona Electric Power Cooperative, Inc.

AEPCO

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.

APPLICATION

for

GENERAL RATE RELIEF

DOCKET NO. E-01773A

JULY 2012

A Touchstone Energy® Cooperative

A

DIRECT TESTIMONY OF PETER SCOTT

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

GENERAL RATES APPLICATION

July 2012

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter Scott. 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 Director of Financial Operations for Sierra Southwest Cooperative Services ("Sierra Southwest") and, as such, I supervise the financial activities of the cooperative. 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. As Director of Financial Operations, I serve on the Division Managers Group and report directly to the Chief Financial Officer. My specific responsibilities for AEPCO include establishing fiscal policy, procedures development and implementation of appropriate financial controls. I am also responsible for 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 Bachelor of Arts Degree in History from Colorado College and completed my graduate and undergraduate Accounting and Finance studies at the University of Arizona. I began my employment with Sierra Southwest in December of 2011. Prior to joining Sierra Southwest, I worked in the Biotechnology Manufacturing industry for 11 years, most recently serving as

Finance Director at Labcyte Inc. I previously worked as Accounting Manager in the Commercial Printing industry for six years.

Q. Mr. Scott, 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, provides more specific details regarding the request and the A-H rate filing schedules which support it.

BACKGROUND

Q. Mr. Scott, please describe AEPCO.

A. AEPCO is a not-for-profit, generation cooperative which serves all or a portion of the wholesale power needs of its three all-requirements ("ARM")[1] and three partial-requirements ("PRM") Class A Member distribution cooperatives. We have one Class A ARM in south-central California—Anza Electric Cooperative, Inc. The two Arizona ARMs are Duncan Valley Electric Cooperative, Inc. and Graham County Electric Cooperative, Inc. Our three PRMs are Mohave Electric Cooperative, Inc. ("MEC"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Trico Electric Cooperative, Inc. ("TRICO"). 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 ARM has a contract with AEPCO that requires it to buy, and AEPCO to plan for and furnish, all of its present and future power

[1] The three Class A Member Distribution Cooperatives are also referred to as the Collective All-Requirements Members or CARMs in various contracts and agreements.

requirements. A PRM, instead, contracts with AEPCO to furnish only a portion of its retail sales 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. TRICO became a PRM on January 1, 2011 and that conversion was approved by the Commission in Decision No. 72055.

Q. **Does AEPCO have other members?**

A. Yes. Valley Electric Association, Inc. became a Class D Member in 2007. It has a service contract for scheduling and trading services. It does not take any power or energy from AEPCO.

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, which is located near Willcox, 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, AEPCO currently uses the South Point and Griffith purchased power contracts to provide summer peaking capacity and energy to the ARMs and TRICO.

Q. **How is AEPCO governed and managed?**

A. AEPCO's Board of Directors oversees all aspects of our operations. It is comprised of 13 members. Twelve of those Board members (two per Class A

Member) are the ARM and PRM distribution cooperatives' representatives who are selected by the distribution cooperative Boards. Those Boards, in turn, are elected by their retail member/consumers. The remaining AEPCO Board member represents the Class D Member. AEPCO, SWTC and Sierra Southwest operate collectively as Arizona's G&T Cooperatives and are managed by a single Chief Executive Officer and Division Managers Group.

Q. **Mr. Scott, please describe AEPCO's most recent rate authorization.**

A. AEPCO's current rates were approved by Decision No. 72055 and took effect on January 1, 2011. In addition, the Decision approved continuation of the Purchased Power and Fuel Adjustor Clause ("PPFAC"). At AEPCO's request, Decision No. 72735 made certain modifications to AEPCO's base and PPFAC rates, which were approved in Decision No. 72055. Those changes became effective on January 1, 2012.

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 meetings were held to discuss the need for, and the elements of, AEPCO's rate filing. In addition, we met with the distribution cooperatives' staffs and consultants to review the revenue requirement aspects of the filing. Our purpose was to develop as much consensus on as many issues as possible. We believe that we have made significant progress on that front. AEPCO's Board of Directors approved the filing of this rate case by a unanimous vote during its June 2012 meeting.

OVERVIEW OF FILING

Q. Please summarize AEPCO's rate request.

A. Mr. Pierson testifies concerning the specifics of the request. But, in general, AEPCO requests an overall 2.92% decrease in its revenue requirements, which is a blend of a 1.30% decrease in revenues from ARMs and a 3.12% decrease in revenues from PRMs. AEPCO requests that the new rates take effect no later than November 1, 2013 and that AEPCO's PPFAC be continued with the modifications and the efficacy provision authorization described in Mr. Pierson's testimony. As I'll discuss, we also ask that the Commission approve revised depreciation rates. SWTC is also preparing a rate request that is scheduled to be filed with the Commission shortly after AEPCO's submission. We request that the implementation date of both AEPCO and SWTC's new rates be synchronized.

Q. Why is there a difference as to how the overall decrease in AEPCO's revenue requirements impacts members?

A. The ARMs and TRICO purchased their other resources from AEPCO during the test year, while MEC and SSVEC elected to purchase requirements in excess of base resources from other parties. Therefore, MEC's and SSVEC's peaking capacity and energy costs are not included as part of AEPCO's revenue requirements. The incremental differences between the generation mix fuel prices, as well as the capacity and energy costs associated with additional resources, resulted in less of a decrease for the ARMs and a slight increase for TRICO.

Q. Do the Class A Members benefit from cost recoveries and margins 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 has achieved in the test year in its sales to others. Thus, those proceeds from 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. Mr. Scott, is AEPCO requesting Commission approval of a change in its depreciation rates pursuant to A.A.C. R14-2-102 in this rate application?

A. Yes. As Mr. Pierson explains in his testimony, AEPCO must periodically review and revise its depreciation rates in order to meet the regulatory requirements of the Rural Utilities Service. In that regard, AEPCO contracted with Black & Veatch Corporation ("B&V") to conduct an assessment study of the gas- and coal-fired units at Apache Station. A copy of B&V's May 2011 study is attached as Exhibit PS-1. Based on that study, attached as Exhibit PS-2 is a summary of the revised depreciation rates for production units and additions prior to December 31, 2013, rates for additions after December 31, 2013 and net decommissioning cost amortization. AEPCO requests Commission approval of the depreciation rates shown on Exhibit PS-2.

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

A. AEPCO is requesting operating margins of $931,000. On a cash basis, the requested margins would generate approximately $5.0 million of working capital on an annual basis. We have reviewed AEPCO's working capital needs going forward and have determined that we should build gradually to approximately $20 million in working capital to support operational requirements. The margins we request in this case will assist in the process of achieving that working capital level over the next few years.

CONCLUSION

Q. Do you have any concluding remarks?

A. We ask that the Commission enter its Order authorizing (1) the implementation on or before November 1, 2013 of the ARM and PRM rates we have requested; (2) the revised depreciation rates stated in Exhibit PS-2; and (3) continuation of the PPFAC as described in Mr. Pierson's testimony.

Q. Does that conclude your direct testimony?

A. Yes, it does.

EXHIBIT
PS-1

EXHIBIT PS-1

BUILDING A WORLD OF DIFFERENCE®

Arizona Electric Power Cooperative, Inc.
A Touchstone Energy® Cooperative

Arizona Electric Power Cooperative

Affirmation of Unit Life & Net Salvage Value Study

FINAL REPORT

B&V Project Number: 168868
B&V File Number: 40.0000

May 2011

Black & Veatch Corporation • 11401 Lamar Avenue • Overland Park, Kansas 66211 • Tel: (913) 458-2000 • www.bv.com

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Report Revisions and Record of Issue

Rev.	Date	Issue Status	Revisions and Record of Issue	EDT	CHK	APP
A	03/10/11	Draft	Issued for Client Review (w/o Decommissioning Costs & Salvage Value)	WEJ	MED	PLW
B	03/25/11	Draft	Issued for Client Review (w/ Decommissioning Costs & Salvage Value)	WEJ	RLF	PLW
0	05/12/11	Final	Issue for Client Records	WEJ	DLD	PLW

BLACK & VEATCH

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List of Acronyms

AEPCO	Arizona Electric Power Cooperative, Inc.
B&V	Black & Veatch
CC	Combined Cycle
EAF	Equivalent Availability Factor
EFOR	Equivalent Forced Outage Rate
EOC	End of Contract
EOL	End of Life
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
FO2	No. 2 Fuel Oil
GAG	Gross Annual Generation
GE	General Electric
GT	Gas (or Combustion) Turbine
IEEE	Institute of Electrical and Electronic Engineers
LTPA	Long Term Purchase Agreement
LTSA	Long Term Service Agreement
NCF	Net Capacity Factor
NERC GADS	North American Electric Reliability Corporation Generating Availability Data System
OEM	Original Equipment Manufacturer
OFA	Over-Fire Air
O&M	Operations & Maintenance
SCR	Selective Catalytic Reduction
ST	Steam Turbine
VFD	Variable Frequency Drive

1.0 Executive Summary

1.1 Introduction

Arizona Electric Power Cooperative, Inc.'s (AEPCO) Apache station located near Cochise, Arizona contains a mix of coal and natural gas fired generation. AEPCO is interested in aligning unit depreciation with the current expected life of the units. Black & Veatch was engaged to provide a high level assessment of the probability of continued operation of these units to their planned end of life and to provide order of magnitude demolition costs and salvage value that AEPCO could expect to incur at the conclusion of the useful life of each respective unit.

Table 1-1 provides an overview of the AEPCO units and their current end of contract and possible decommissioning dates as provided by AEPCO.

Table 1-1 Generating Unit Summary

Unit	Fuel	Net Rating[1] MW	Typical Service	Year in Service	Contracted Through
GT1[2]	Natural Gas	10 / 10	Peaking	1963	2020
GT2	Natural Gas / FO2	18.5 / 20	Peaking	1972	2020
GT3	Natural Gas	60 / 63	Peaking	1975	2020
GT4	Natural Gas / FO2	38 /44	Peaking	2004	2035
ST1[2]	Natural Gas	72	Peaking	1964	2020
ST2[3]	Coal / Natural Gas	175	Load Following	1979	2035
ST3[3]	Coal / Natural Gas	175	Load Following	1979	2035

(1) Summer / winter net ratings reported from data available in the public domain.
(2) ST1 can run independently or in a combined cycle mode GT1.
(3) ST2 and ST3 can achieve full load on coal or gas.

1.2 Approach

Black & Veatch's assessment of the Apache units' current condition and expected useful life was based on the following approach.

- Site visit to visually assess general plant conditions.
- Interviews with key personnel to understand historical plant operations and maintenance (O&M) practices, equipment issues, and planned outages, upgrades, and capital expenditures.
- Review of reports, historical records and performance indicators.
    - Previous life assessments.
    - Outage reports (including equipment test records).
    - O&M and capital expenditures.

- Unit historical operation and performance data (heat rate, capacity factor, EFOR, availability, number of starts, emissions).
- Fuel sources and quality.

- Review of projected unit operations and maintenance.
- Review of support infrastructure and other information.
  - Organization charts.
  - Environmental compliance and pending issues.
  - Presence of hazardous materials (asbestos, lead paint, etc.).
  - Waste treatment and disposal.
  - Weights of major equipment.

Based on this understanding of the current condition combined with the projected utilization and planned maintenance activities Black & Veatch has developed an assessment and opinion regarding the potential to continue the utilization of the assets consistent with the expected remaining useful life for each respective generator.

1.3 Useful Life Assessment

The plant appeared to be in reasonably good condition and maintaining good housekeeping practices. Some general wear and tear was noted and consistent with the expectation for units of these vintage. Normal maintenance was underway along with some capital additions such as the addition of a second limestone ball mill. Plant staff advised that the station was preparing for an extended ST3 outage.

Apache Station has settled approximated 4 feet because of pumping that has lowered the ground water level within the Wilcox Basin. Settlement across the station has not been uniform with larger reported differentials in the east - west direction compared to the north-south direction. The 2007 study indicated some tilting of the turbine generators and some bowing of the high pressure-intermediate pressure turbine shells. This was likely caused by pipe loading.

Discussions with plant staff during the site visit indicated that purchases of surrounding farmland has reduced water competition and consumption rates and use of remote wells has reduced the settlement rate around the plant. The plant must continue to monitor subsidence and continue to take corrective actions to reduce the resulting impacts on equipment, structures, and piping.

1.3.1 GT1/ST1

The average annual capacity factor over the last 5 years is approximately 7.3 percent. Operating at the projected 25 percent capacity will increase wear and tear on the unit requiring more frequent outages and higher capital expenditures. In order for GT1 to operate at such a high capacity factor over the next 9 years major maintenance of the combustion turbine and rewind of the generator may be required. The turbine/generator OEM General Electric (GE) has recommended rewinding of the stator and could offer no estimate of its remaining life.

A more likely scenario would be to continue operating as a seasonal peaking unit with an average 5 to 10 percent capacity. In the event of catastrophic failure, AEPCO would have the option of repairing or replacing the required equipment or decommissioning the unit and operating ST1 independently to end of life. The availability of replacement parts and economics would dictate this decision.

Based on information obtained from the site visit, staff interviews, and outage reports, it is anticipated the ST1 will be able to continue operation to 2020 provided AEPCO continues to operate and maintain unit equipment.

As a minimum AEPCO should continue to:

- Perform annual borescope inspections of the unit to monitor internal conditions of the turbine.
- Perform inspections and overhauls in accordance with OEM recommendations including partial discharge (PD) tests on the generator.
- Continue routine preventive maintenance.
- Consider operating ST1 independent of GT1 if higher annual capacity factors are required.

1.3.2 ST2 & ST3

Based on information obtained from the site visit, staff interviews, and outage reports, it is anticipated the ST2 and ST3 can continue operation to 2035 provided AEPCO continues to maintain good operations, maintenance and safety practices, and to expand the capital required for periodic replacement/refurbishment of the equipment. As a minimum, AEPCO must:

- Continue to monitor plant settling issues and take proactive measures to reduce settlement rates and to correct resulting stresses on plant structures and equipment.
- Perform inspections and overhauls in accordance with OEM recommendations.
- Continue crawl through inspections of the boilers during scheduled outages.
- Continue routine preventive maintenance.
- Maintain good housekeeping practices, particularly in coal handling areas to minimize fire/explosion potential.

It should be noted that Black & Veatch's evaluation did not consider the impact of future environmental requirements on the unit. Impacts such as mandated CO_2 capture, installation of SCR for NO_x reduction, etc. can impact the economic viability of future operations.

1.3.3 GT2, GT3 & GT4

As shown in Table 1-2, AEPCO expects to operate GT2 and GT3 at slightly higher capacity factors in the future. GT4 is expected to operate at a significantly higher capacity factor.

Outages are typically based on the number of starts and operating hours. Plant staff reported the GT3 has over 12,000 hours of operation and is scheduled for a major overhaul in 2012.

Table 1-2 GT Historical and Projected Capacity Factor Comparison

Unit	Historical Average Capacity Factor 2006 - 2010	Projected Average Capacity Factor 2011 - EOL
GT2	< 1%	2 %
GT3	< 2%	5%
GT4	10.5%	25%

AEPCO's proposed plan will require an increased number of starts and higher operating hours. Both events will reduce the calendar period between required overhauls and increase required capital and operating budgets over historical values. It should be noted that combustion turbine performance degrades over time between overhauls and with an increasing number of starts. The majority of this performance loss is typically recaptured during overhaul.

As a minimum, AEPCO should:

- Complete the planned major overhaul of GT3 in 2012.
- Perform annual borescope inspections of the unit to monitor internal conditions of the turbine.
- Perform other inspections and overhauls in accordance with OEM recommendations based on number of starts and operating hours.
- Continue routine preventive maintenance.

1.3.4 Major Electrical Equipment

Black & Veatch's evaluation of the major electrical equipment is based on discussions with AEPCO staff, review of outage reports, review of submitted test data, and observations during the site tour. No major issues of concern were noted. The following recommendations are made to ensure continued operation to the planned equipment end of life.

- Continue existing maintenance and inspection program.
- Monitor generator vibration levels with the consideration that shorted rotor turns will exhibit increased levels.
- Continue oil sampling on all large oil filled transformers; include periodic Doble testing of winding and bushing power factor. In addition, include degree of polymerization analysis on transformer oil (as part of Furan screen) to determine remaining life of insulation system.
- Log top oil and winding temperature readings from local indicators to support early detection of adverse loading trends.
- Test the grounding system and verify connections to below grade grid for high structures.
- Test medium voltage switchgear and underground cable as recommended in section 6.2 of this report.

1.4 Decommissioning Cost & Salvage Value Assessment

A set of decommissioning assumptions was developed based on discussions with AEPCO corporate and plant staff. These discussions focused on safety and security requirements, known hazardous materials that would be encountered during demolition, and final site conditions. A complete list of assumptions is shown in Section 7 of the report.

1.4.1 Decommissioning Cost

The total estimated cost to decommission the Apache Station is approximately 61 million dollars ($61,100,000). A detailed breakdown of estimated decommissioning costs are shown in spreadsheets included in Appendix A.

1.4.2 Salvage Value

Scrap values used in this study are based on discussions with Tucson Iron & Metal Company and reflect March 2011 values. The total estimated salvage value of Station equipment is approximately 14.4 million dollars ($14,400,000).

1.5 Conclusion

Based on information obtained from the site visit, staff interviews, outage reports, and Black and Veatch's experience with other unit of similar design and vintage it is anticipated AEPCO can continue operation of the Apache units until their current end of contract dates provided AEPCO continues to maintain good operations, maintenance and safety practices and expand the capital required for periodic replacement/refurbishment of the equipment.

2.0 Introduction

Arizona Electric Power Cooperative, Inc.'s (AEPCO) Apache station located near Cochise, Arizona contains a mix of coal and natural gas fired generation. AEPCO is interested in assessing the probability of continued operation of these units to their current end of contract with AEPCO's Class A members as well as order of salvage value and demolition and salvage value at the anticipated end of life. Black & Veatch (B&V) was hired to perform a high level review of Apache Station's plans including pricing information based on their experience and available industry data.

2.1 Station Summary

Apache Station is comprised of a mixture of fossil fuel fired boilers / steam turbines (ST) and gas (combustion) turbine (GT) generation. Table 2-1 provides a summary of the station generating units.

Table 2-1 Generating Unit Summary

Unit	Fuel	Net Rating[1] MW	Typical Service	Year in Service	Contracted Through
GT1[2]	Natural Gas	10 / 10	Peaking	1963	2020
GT2	Natural Gas / FO2	18.5 / 20	Peaking	1972	2020
GT3	Natural Gas	60 / 63	Peaking	1975	2020
GT4	Natural Gas / FO2	38 /44	Peaking	2004	2035
ST1[2]	Natural Gas	72	Peaking	1964	2020
ST2[3]	Coal / Natural Gas	175	Load Following	1979	2035
ST3[3]	Coal / Natural Gas	175	Load Following	1979	2035

(1) Summer / winter net ratings reported from data available in the public domain.
(2) ST1 can run independently or in a combined cycle mode GT1.
(3) ST2 and ST3 can achieve full load on coal or gas.

The plant is located near a large natural gas transmission line. Sufficient capacity is typically available to meet plant demands during peak summer conditions. Interruptions were only noted during extended periods of unusually cold weather. An onsite compressor station is located near GT4 to ensure sufficient pressure to meet LM6000 full load requirements.

Coal is supplied by unit train from western bituminous and subbituminous coal sources. Onsite blending capability is available through the existing coal reclaim system.

Number 2 Fuel Oil (FO2) is currently supplied by truck and stored in a storage tank near GT4. The fuel is also used by the plant mobile equipment to ensure the fuel is turned over and does not degrade. GT4 is permitted for fuel oil operation. Plant staff advised their strategy would be to keep the tank filled in a long term event. Other fuel oil tanks located on the north end of the site have been emptied and are on standby. The fuel oil supply and transfer systems to GT2 are on standby and would require refurbishment before use. Plant staff has advised that tanker trucks have been used to support short term test firing with oil, but the plant plans to maintain duel fuel capability for the indefinite future.

The gas turbine units are air cooled. The steam turbine units utilize mechanical draft cooling towers for heat rejection.

The station is located in the Wilcox Basin with more than 1,000 feet of alluvial sediments. Water for agricultural and industrial use in the basin, including site use, is obtained from wells installed within the alluvium. As a result of the ground water use, the load applied by the dewatered soil to underlying soils increases, causing compression of the underlying soil and settling of plant structures including ST2 and ST3.[1] The plant periodically monitors this settlement and impacts on large equipment including the turbine generator, boilers, stack, ESP, and high energy piping. AEPCO has taken steps to reduce regional water competition and settlement rates through the purchase of surrounding farmland.

ST2 and ST3 are typically operated in a load following mode. ST1 and GT1 and the gas turbine units GT2, GT3, and GT4 typically operate during seasonal peaking conditions. Historical capacity factors and reliability data are shown in Table 2-2. Projected capacity factors are shown in Table 2-3.

Table 2-2 Historical Reliability Statistics

Unit	Year	EFOR %	EAF %	NCF %	GAG MWH
ST1	2005	16.58	85.44	7.74	56,439
	2006	1.12	89.83	5.96	44,945
	2007	54.19	76.21	7.97	57,931
	2008	36.26	94.31	4.64	35,476
	2009	77.17	31.97	5.34	39,657
	2010	0.28	43.57	0.38	5,217
ST2	2005	2.96	86.86	83.44	1,436,884
	2006	0.66	99.29	96.86	1,650,748
	2007	1.13	98.17	94.88	1,620,357
	2008	1.75	85.33	80.61	1,383,397
	2009	1.94	88.94	67.70	1,182,585
	2010	1.64	87.43	60.29	1,057,078
ST3	2005	0.88	98.36	96.71	1,648,628
	2006	2.96	85.24	82.82	1,416,224
	2007	1.22	98.77	98.08	1,669,577
	2008	0.38	98.55	95.85	1,643,885
	2009	10.93	79.76	63.28	1,090,984

[1] Arizona Electric Power Cooperative, Inc. Apache Generating Station ST3 High Energy Piping and Subsidence Study, Black & Veatch Corporation, May 2007

Table 2-2 Historical Reliability Statistics					
Unit	Year	EFOR %	EAF %	NCF %	GAG MWH
	2010	0.30	97.03	79.49	1,362,597
GT1	2005	1.51	99.10	11.92	10,450
	2006	13.48	66.19	8.66	7,597
	2007	2.14	90.23	13.29	11,651
	2008	10.61	93.24	8.83	7,760
	2009	71.11	52.26	5.03	4,407
	2010	46.89	44.06	0.63	556
GT2	2005	39.27	98.44	0.90	92
	2006	1.41	99.97	0.74	1,292
	2007	94.19	92.76	0.05	78
	2008	97.49	96.03	0.07	116
	2009	96.71	97.18	0.06	99
	2010	90.31	98.57	0.03	56
GT3	2005	11.22	97.20	15.59	5,491
	2006	43.84	98.89	0.68	4,333
	2007	91.08	69.46	0.59	3,752
	2008	75.42	93.43	0.56	3,672
	2009	14.24	98.78	2.77	15,867
	2010	14.44	81.36	2.08	12,048
GT4	2005	2.92	92.98	59.51	52,635
	2006	12.28	95.93	12.14	41,412
	2007	19.28	94.63	13.24	45,014
	2008	61.85	79.65	7.62	28,531
	2009	50.45	81.66	10.84	39,919
	2010	18.59	95.39	8.59	32,007

Table 2-3 Projected Capacity Factors		
Unit	Year(s)	NCF%?
ST1/GT1	2011 - 2020	25.0
GT2	2011 - 2020	2.0
GT3	2011 - 2020	5.0
GT4	2011 - 2020	25.0
ST2	2011	69.11
	2012	57.99
	2013	68.67
	2014	60.12
	2015	79.68
	2016	73.79
	2017	86.09

Table 2-3 Projected Capacity Factors		
Unit	**Year(s)**	**NCF%?**
	2018	79.48
	2019	90.53
	2020	82.83
ST3	2011	70.79
	2012	95.00
	2013	87.25
	2014	95.00
	2015	89.49
	2016	95.00
	2017	86.03
	2018	95.00
	2019	90.27
	2020	95.00

2.2 Project Approach

B&V's project approach to the evaluation of generating unit life is based upon a process of evaluation after consideration of each of the following:

- Current condition.
- Historical utilization.
- Forecast utilization.
- Expected decommissioning horizon.

Our process then compares those findings with typical industry practice and experience to provide an opinion regarding the likelihood of the equipment reaching the expected decommissioning date after factoring anticipated maintenance and/or other investment. This approach was broken into the following steps.

2.2.1 Step 1 – Data Request & Review

B&V assembled a list of data to be reviewed as part of the assessment. Where possible, data provided by AEPCO was reviewed prior to the site visit to help focus visual investigations and interview questions on historical issues. Information requested from AEPCO included the following:

- Historical performance indicators.
  - Winter and summer capacity.
  - Winter and summer heat rate.
  - Capacity factor.
  - Annual generation.
  - Number of starts.

    - Service hours.
    - EFOR and equivalent availability.
- Performance targets.
- Fuel quality data.
- Previous life assessment studies.[2,3]
- Reliability data and reports.
- Equipment inspection reports.
- Outage reports.
- O&M and capital targets / projections including details on unit and component.
- CMMS Utilization.
    - Tools and methodology.
    - Maintenance performance reports.
    - Maintenance backlog for outage and non-outage work.
    - Maintenance history.
- Other Useful Information.
    - Organization charts.
    - Copies of Benchmarking data or studies that were either performed in-house or that were provided by others.
    - Any environmental compliance or permitting issues on the horizon.
    - Presence of hazardous materials such as asbestos, lead paint, PCB contaminated oil, etc.
    - Waste treatment and disposal.
    - Details of existing O&M Agreements or LTSAs/LTPAs.
    - Details regarding reagent sources.
    - Weights of major equipment for estimating salvage value.

2.2.2 Step 2 – Site Visit

A site visit/plant walk down was conducted by three B&V engineers familiar with operations and maintenance of coal fired generating units and combustion turbines on February 15 and 16, 2011. The intention was to assess the general condition of the plant and key equipment including:

- Boilers and draft equipment.
- Fuel handling and preparation equipment.
- Steam turbine and auxiliary equipment.

[2] Arizona Electric Power Cooperative, Inc. Apache Generating Station Combined Cycle Unit No. 1 Life Assessment Study, Burns & McDonnell June 1991 & July 1992
[3] Arizona Electric Power Cooperative, Inc. Apache Generating Station Units 2&3 Major Power Generation And Plant Electrical Equipment Condition Assessment Report, Burns & McDonnell June August 2003

- Emission control equipment.
- Ash handling and storage.
- Combustion turbines.
- Generators.
- Medium Voltage Electrical switchgear.
- Large Transformers.
- Large Motors.

Following completion of site safety training, an initial tour of the plant site was conducted by Mr. David Murray. The B&V team was given access to requested locations which included the GT1/ST1 area, ST2 and ST3 turbine decks, ST2 & 3 boilers, common station control room, ST2 and ST3 feed and condensate systems, tripper deck, pulverizers, ESPs, FGD equipment, and the coal yard. Access to GT2 and the water treatment building was also provided. The specific scope of service for the project did not call for inspection or entry into tanks or confined spaces. The general conditions of cooling towers and energized electrical equipment such as transformers were observed from a safe distance. Tours of GT3 and GT 4 were conducted on the morning of February 16.

The plant appeared to be in reasonably good condition and maintaining good housekeeping practices. Some general wear and tear was noted all of which appeared consistent with the expectation for units of these vintage. Plant staff advised the station was preparing for an ST3 outage which would include the addition of Hastelloy cladding to the stack liner to resist acid attack at low stack temperatures. The ST2 stack would be clad during its next outage.

2.2.3 Step 3 – Interviews with Key Personnel

The B&V team met with operations, maintenance, and environmental representatives from the plant and corporate staff. After brief introductions the group began to systematically discuss general plant practices, historical issues, and planned upgrades or capital additions by major system or equipment item for each unit. These discussions resulted in additional data requests from the B&V team.

The AEPCO staff was cooperative and supplemented discussions with additional reports and data where available.

2.2.4 Step 4 –Review of Projected Operations, Planned Maintenance, and Capital Expenditures

AEPCO conducts short (3 year) and long range (10 year) maintenance and capital upgrade planning. The long range plan is currently undergoing update. A copy of a December 2008 plan was provided for review. Copies of two short range (2005 through

2008 and 2009 through 2011) Summary of Construction Program and Cost spreadsheets were also provided for B&V review.

Minor boiler outages are currently conducted on the ST units every two years. This typically include crawl though inspections of the boiler as evidenced by several TJR Technical Services, Inc. reports provided by AEPCO staff for B&V review. Major boiler outages have historically been conducted every 8 years, however, AEPCO staff advised this has moved to a 6 year cycle to coincide with major turbine outages. Major generator outages are conducted as needed.

Historical average and 2011 projected O&M expenditures are shown in Table 2-4. Costs include operation staff, maintenance of the units, structures, and other miscellaneous equipment, and amortization of overhauls. Long range estimates were not provided for review.

Table 2-4 Historical and Estimated O&M Expenditures

Unit	2008 - 2010 Annual Average	2011 Projected
GT1	$49,410	$54,960
GT2	$46,490	$51,710
GT3	$383,430	$426,440
GT4	$323,620	$369,920
ST1	$1,329,800	$1,478,960
ST2	$7,582,770	$8,433,350
ST3	$10,075,940	$11,206,180
Overall Plant	$19,791,460	$22,011,520

Plant 2011 capital expenditures are projected to be approximately $11,782,400. The December 2008 long range plan estimated 2012 capital expenditures would be approximately $13,911,300. Subsequent year expenditures through 2018 were assumed to increase by 3 percent. The majority of 2011 capital expenditures were directed toward ST2 and ST3. No specific GT expenditures were noted in the 2011 budget provided for review.

AEPCO typically capitalize any expenses over $25,000.

2.2.5 Step 5 – Decommissioning and Net Salvage Value Estimates

A set of decommissioning assumptions was developed based on discussions with AEPCO corporate and plant staff. These discussions focused on safety and security requirements, known hazardous materials that would be encountered during demolition, and final site conditions. A detailed list of these assumptions is included in Section 6 of this report but generally includes:

- Decommissioning dates.
- Ownership assumptions.

- Site security requirements.
- Presence of contaminants such as lead and asbestos.
- Assumed / allowable site conditions.
- Demolishing methods (dynamite, cutting and disassembly, etc.)

Decommissioning costs were based on B&V estimates for similar type and size units and adjusted to reflect regional costs and values. Salvage value estimates are based on typically saleable materials and estimated quantities. Decommissioning costs and salvage values are presented in 2011 dollars.

2.2.6 Step 6 – Reporting

The results of B&V's investigations, assessments, and estimates were consolidated into this report. The report was reviewed internally by B&V and then a draft submitted to AEPCO for review and comment.

3.0 GT1 / ST1 Affirmation of Unit Life

3.1 Background and Description

3.1.1 GT1

GT1 is a natural gas fired, simple cycle GE MS5001D combustion turbine. Exhaust gas is ducted to the adjacent ST1 fired boiler to allow the units to operate in a combined cycle mode. GT1 is operated in combined-cycle with ST1. An air washer is used to increase capacity during hot weather.

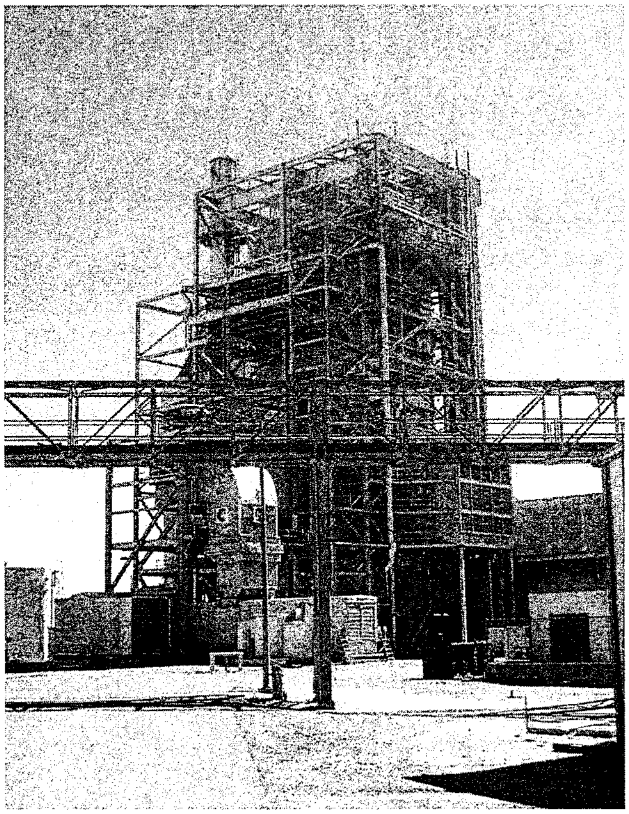

Figure 3-1 GT1 / ST1

GT1 is the oldest unit on the site with an average annual capacity factor of approximately 6.6 percent over the last six years.[4] The GT was replaced with a rebuilt GT of same model, specs, frame and vintage in 2000, but still carries the same OEM designation. A major inspection of the unit was conducted in early 2010 by the Wood Group. Unplanned work activities during the outage included removal of the 1st stage buckets for inspection,

[4] 2005 through 2010.

and removal of the lower half of the exhaust diffuser for resealing. Plant staff advised the controls were also upgraded during this outage.

During the same period the Generator Stator was visually inspected by General Electric (GE) and TurboCare Generator Services. Their reports indicates the generator contains the original asphalt-mica winding and original flat windings with maple fill and that the general cleanliness was poor due to the open ventilation system and the presence of coal dust in the air. GE recommended a full stator rewind based on the age of the unit, but understood the unit was to be contracted through the next ten years. The present plan by AEPCO not to proactively rewind the generator is prudent based on the limited running hours coupled with relatively low potential payback and risk of failure. Some areas of corona were observed throughout the unit which was attributed to the amount of coal dust contamination. Coal contamination and areas of corona will continue to occur. GE could not determine the level of insulation damage or remaining life of the unit in this condition. Cleaning was recommended, but care must be taken not to damage the stator components.

3.1.2 ST1

ST1 is a natural gas fired boiler. ST1 can be operated independently or heat from the boiler burners can be supplemented by exhaust gas from GT1. ST1 is the oldest of the steam units and typically operates only in peaking mode. The average capacity factor over the last six years[1] is approximately 5.33 percent.

Excess heat from the turbine cycle is removed by nearby cooling tower. The redwood tower was rebuilt in 1995 and is equipped with a fire protection system. Staff advised the towers only require routine maintenance.

A major boiler outage was conducted in 2010. Plant staff advised that approximately 85 percent of the furnace tubes were replaced during this outage. Condenser water box cleaning and anode replacement was also completed. Some condenser tubes have been plugged. Coatings and circulating water pipe repairs were not included in the outage. The circulating water pumps were rebuilt in 2009 and 2010. The original air removal equipment operates satisfactorily. AEPCO plans to replace the dog bone expansion joint.

No issues were reported with the boiler draft equipment.

Sagging of high energy piping was reported in a 1996 study. The sagging has been addressed and recent inspections have not noted any subsequent problems. Plant staff advised high energy piping is inspected every 6 years.

No. 4 feedwater heater was recommended for replacement as part of the 1992 study. The plant has elected to bypass the heater and has no current plans to replace. The bypass of the heater results in an efficiency loss but has no affect on the physical plant remaining life.

The turbine nozzle block was replaced in 2000. The most recent major turbine generator outage was conducted in early 2009 by Energy Engineering & Construction, Inc and Mechanical Dynamics and Analysis, Ltd. Work activities included turbine repairs and a rewedging of the generator stator. During the stator rewind, contamination from the lead based solder used in two of the original coolers was noted and abated. This contamination is expected to continue and be present during future outages. Abatement should be included in cost and schedule estimates.

3.2 Conclusions and Recommendations

3.2.1 GT1

The average annual capacity factor over the last 5 years is approximately 7.3 percent. Operating at the projected 25 percent capacity will increase wear and tear on the unit requiring more frequent outages and higher capital expenditures. It is not likely that the unit could operate at such a high capacity over the next 9 years without a major maintenance inspection of the combustion turbine and rewind of the generator. GE previously recommended rewinding of the stator and could offer no estimate of its remaining life.

As a minimum, AEPCO should continue to:

- Perform annual borescope inspections of the unit to monitor internal conditions of the turbine.
- Perform inspections and overhauls in accordance with OEM recommendations based on number of starts and operating hours.
- Continue routine preventive maintenance.

3.2.2 ST1

Based on information obtained from the site visit, staff interviews, and outage reports, it is anticipated the ST1 will be able to continue operation to 2020 provided AEPCO continues to operate and maintain unit equipment. As a minimum AEPCO should continue to:

- Perform annual borescope inspections of the unit to monitor internal conditions of the turbine.
- Perform inspections and overhauls in accordance with OEM recommendations.
- Continue routine preventive maintenance.
- Consider operation independent of GT1 if higher annual capacity factors are required.

4.0 ST2&3 Affirmation of Unit Life

4.1 Background and Description

Apache Generating Station Units 2 and 3 are essentially identical units commissioned in 1979, each having a gross nameplate rating of 195 MW. Coal is the primary fuel, but the units have been modified to achieve full load on either coal or natural gas. AEPCO may also consider co-firing of the two fuels in the future.

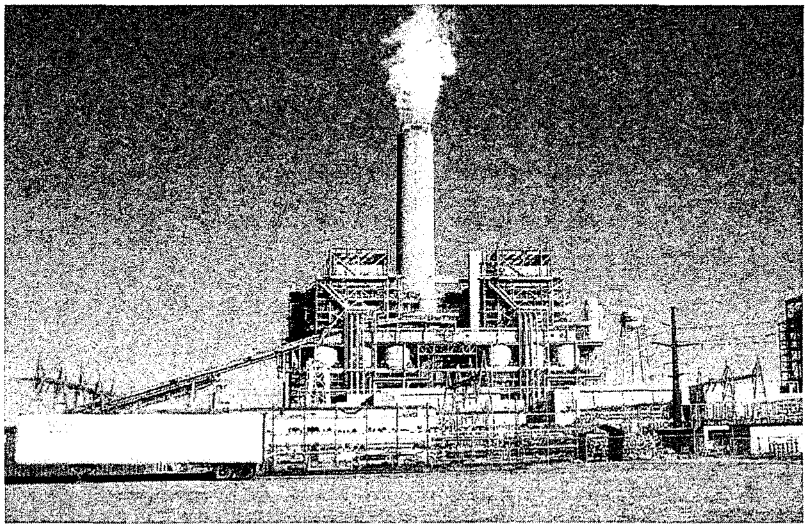

Figure 4-1 ST2 and ST3

4.1.1 Steam Generator and Support Equipment

ST2 and ST3 are equipped with Riley Stoker balanced draft, radiant type, turbo fired steam generators. The units are rated at 1,355,000 lbs/hr at 2620 psig / 1000°F main steam outlet and 1000°F reheat steam outlet conditions. Coal is pulverized for each unit by three Kennedy Van Suan ball tube mills and conveyed to the burners by three dedicated PA fans. Two 50 percent capacity forced draft and induced draft fans are provided for each unit. Each unit is supplied with two tri-sector regenerative heat exchangers.

The unit is considering installing variable frequency drives (VFDs) on the ID and possibly the PA fans within the 2012 – 2013 timeframe. No problems were reported with these fans; the proposed changes would allow for better control and reduce station power consumption.

The units' air heater baskets are original and need to be replaced. AEPCO did report that leakage is normal and the seals are in good condition.

4.1.2 Steam Turbine Generator and Support Equipment

Apache 2 and 3 are equipped with General Electric tandem compound, double flow reheat steam turbine generators with a flow of 1,286,627 lb/hr at 2400 psig 1000°F main steam 1000°F reheat steam conditions. The generators are cooled by hydrogen.

Feedwater is supplied through six stations of feedwater heating: three low pressure (LP) stages, deaerator, and two high pressure (HP) heaters. The 2003 life assessment study recommended replacing the ST2 FWH 5 and ST3 FWH 6 heaters with stainless steel (SS) tubes. Plant staff advised these have not been replaced. ST2 FWH 5 and 6 have about 5 to 10 percent of their tubes plugged. ST3 FWH 6 has approximately 12 percent of its tubes plugged. Industry practice suggests feedwater heater replacement is considered after 10% of the tubes are plugged. However the decision to replace or re-tube the heaters is primarily a question of economics weighing the improved heat rate against the capital cost and the time over which the improved efficiency could provide a return on the investment (through fuel savings). Poor feedwater heater performance due to plugged tubes is generally not a capacity concern until the boiler must be fired at a rate higher than the boiler capacity in order to "make up" for the reduced feedwater temperature.

AEPCO is considering installing VFDs on the boiler feedwater pumps (BFPs) in the 2012 - 2013 timeframe. Pumps are typically rebuilt every 6 years. AEPCO maintains one spare volute on site. Plant staff advised an additional stage was added to the Condensate pump bowl assemblies. Motor upgrades were not required since loading is never more than 85 percent.

4.1.3 Emission Control Equipment

Apache 2 and 3 are equipped with hot-side electrostatic precipitators (ESP) for particulate control, wet limestone flue gas scrubbers for SO_2 control, and overfire air (OFA) for NO_x control.

The units share a common reagent preparation system. Limestone for the FGD system is delivered by truck and crushed by a 5 tph mill. Installation of a second, higher capacity ball mill is underway. The foundations were partially completed at the time of B&V's site visit.

Each unit is equipped with 2 absorber modules with multiple pumps and spray levels. Plant staff advised typical SO_2 removal is in the 80% to 85% range and is considered marginal. Equipment upgrades over and above those currently in progress will be required to achieve 95% SO_2 removal. Upgrades recommended in a 2004 Radian study included additional trays and loop spray header, higher capacity slurry recycle pumps. Conversion to forced oxidation may also be required to support higher removal rates. Plant staff advised SCR and FGD upgrades are projected for the 2014 timeframe. Capital cost estimates for these additions were not provided for review.

The unit currently adds calcium bromide to coal during reclaim to reduce mercury levels by approximately 50 percent. The mercury is captured in the FGD waste and stored in a lined on-site surface impoundment. Use of hydrogen bromide or other chemical process would be required to meet higher required levels of mercury removal. Plant staff has not been advised of any impact of the calcium bromide on the salability of the fly ash. Plant staff speculated that there may be some impact on ESP operation, but this needs further investigation.

Plant staff advised that some ESP upgrades were suggested in a 2004 study, but these were not specifically identified. Staff did advise that the ESP controls are adjusted annually to reduce ash carryover. No other ESP related issues were noted.

The units share a common concrete chimney with separate steel liners. The liners have suffered some acid attack from low temperature operation; however, the plant is scheduled to apply Hastelloy cladding to the Unit 3 stack during the scheduled Spring 2011 outage. Unit 2 is scheduled for cladding in 2012.

4.1.4 Miscellaneous Equipment

Apache 2 and 3 are each equipped with a 9 cell mechanical draft cooling towers for heat rejection. Water for the station is supplied from deep wells located on the plant site. Plant staff advised sufficient water rights are available to meet needs. It is assumed that AEPCO will maintain these rights through the remaining life of the units.

Coal is delivered by unit train and off loaded via bottom dump rail cars. Coal is held in stockpile or transported to the three coal bunkers on each unit by conveyor.

Bottom ash and scrubber sludge from the units is hydraulically conveyed (sluiced) to onsite surface impoundments. Fly ash is pneumatically conveyed to silos for sale or disposal in the onsite surface impoundments. Current storage appears to be adequate. It is assumed that additional storage areas will be permitted and developed as needed. Normal periodic maintenance and replacement of the ash piping will be required.

4.1.5 Equipment Subsidence

Apache Station has settled approximated 4 feet because of pumping that has lowered the ground water level within the Wilcox Basin. B&V's 2007 ST3 High Energy Piping and Plant Subsidence Study indicated that at that time the settlement rate was approximately 0.3 to 0.6 feet per year. Settlement across the station has not been uniform with larger reported differentials in the east – west direction compared to the north-south direction. The 2007 study indicated some tilting of the turbine generators and some bowing of the high pressure-intermediate pressure turbine shells. This was likely caused by pipe loading.

Discussions with plant staff during the site visit indicated that purchases of surrounding farmland has reduced water competition and consumption rates and use of remote wells has reduced the settlement rate around the plant. An updated subsidence survey needs to be taken.

4.2 Conclusions and Recommendations

Based on information obtained from the site visit, staff interviews, outage reports, and Black & Veatch's experience with other unit of similar design and vintage it is anticipated the ST2 and ST3 can continue operation to 2035 provided AEPCO continues to maintain good operations, maintenance and safety practices and expand the capital required for periodic replacement/refurbishment of the equipment. As a minimum, AEPCO must:

- Continue to monitor plant settling issues and take proactive measures to reduce settlement rates and to correct resulting stresses on plant structures and equipment.
- Perform inspections and overhauls in accordance with OEM recommendations.
- Continue crawl through inspections of the units during scheduled outages.
- Continue routine preventive maintenance.
- Maintain good housekeeping practices, particularly in coal handling areas to minimize fire/explosion potential.

It should be noted that B&V's evaluation did not consider the impact of future environmental requirements on the unit. Impacts such as mandated CO_2 capture, installation of SCR for NO_x reduction, etc. can impact the economic viability of future operations. Evaluation of the regional market power prices in light of environmental compliance costs that increase the AEPCO operating costs would need to consider both the AEPCO costs and the costs that will be incurred by other generators in the region. Such a market evaluation is beyond the scope of this effort.

5.0 GT 2 – 4 Affirmation of Unit Life

5.1 Background and Description

Peaking service is provided by three simple cycle gas turbines referred to as GT2, GT3, and GT4. GT2 and GT3 are dual fuel capable, but typically fire natural gas. GT3 can only fire natural gas. The combustion turbines are distributed across the site, with sufficient access to support periodic maintenance and overhauls. GT2 and GT3 are contracted through 2020. GT4 is the newest unit on site and is contracted through 2035.

5.2 Equipment Assessments

5.2.1 GT2

GT2 is a simple cycle GE Frame 5N combustion turbine rated at approximately 20 MW. The unit typically fires natural gas but can be fired with FO2. The fuel oil supply system is currently on standby and requires refurbishing. FO operation is tested using tanker trucks to supply the fuel.

The unit normally operates in a peaking mode but is tested monthly. Plant staff advised annual operating hours range between 20 to 100 hours. GT2 start time is approximately 7 minutes so the unit can be considered as spinning reserve.

Per the OEM recommendations and AEPCO practice maintenance intervals are scheduled based on the number of starts or hours of operation. However, in a peaking mode of operation the inspection intervals are typically defined by the accumulated number of starts since the number of operating hours is quite low. Station records indicate a borescope inspection was completed in 2010. A condition assessment report was not available for review.

The unit is contracted through 2020.

5.2.2 GT3

GT3 is a simple cycle, natural gas fired Westinghouse 501B2 combustion turbine rated at approximately 67 MW. The unit is equipped with two evaporative coolers to reduce inlet air temperature; however, the coolers need significant corrosion repairs. The controls system has been updated. Plant staff reported some replacement turbine blades have been purchased but not installed.

Outages are typically based on the number of starts and operating hours. Plant staff reported the unit has over 12,000 hours of operation and is scheduled for a major overhaul in 2012. Startup time is approximately 30 minutes.

GT3 is currently contracted through 2020.

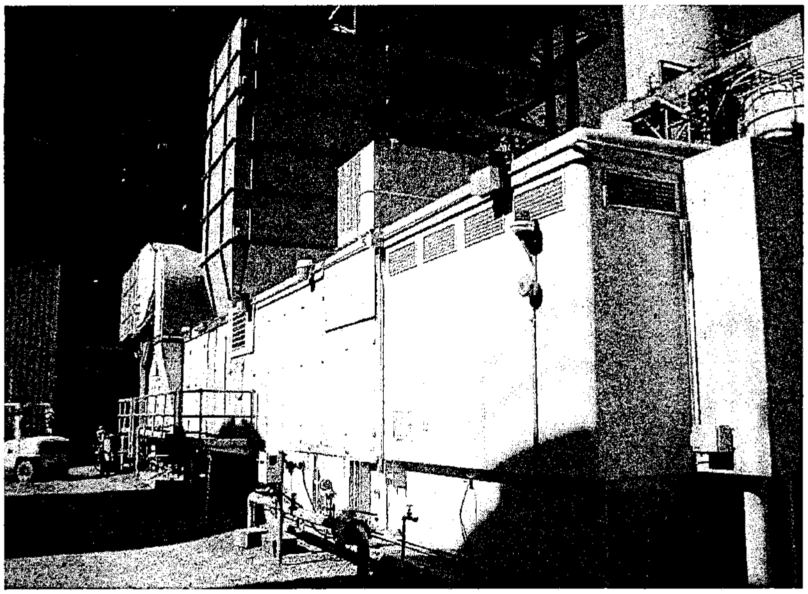

Figure 5-1 GT2

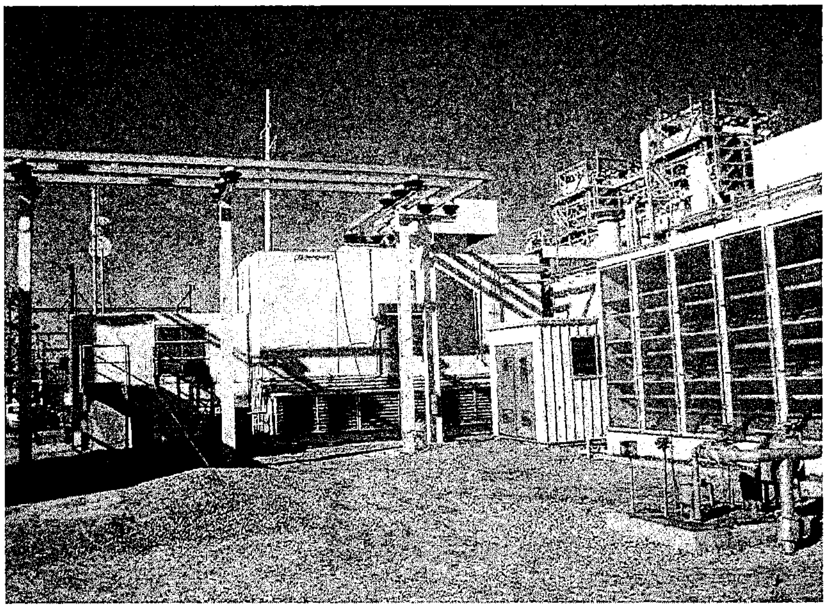

Figure 5-2 GT3

5.2.3 GT4

GT4 is a simple cycle, dual fuel, GE LM6000 rated at approximately 40 MW. The unit can be operated from an adjacent control building or the main plant control room. The unit typically fires natural gas, but can fire FO2 for limited durations from an adjacent tank[5]. LM6000 units require a higher inlet gas pressure due to the higher compression ratio of an aeroderivative unit (as compared to the frame machines GT2 and GT3). A 2 x 100% capacity gas compression station ensures sufficient gas pressure to meet full load requirements.

The unit is equipped with an SCR for NO_x reduction. Tempering air fans are provided to control flue gas temperatures and prevent damage to the SCR catalyst. Ammonium hydroxide is supplied from an adjacent tank.

A detailed assessment report was not available for review. However, no operating or maintenance issues were identified by AEPCO and the unit appeared to be in good working condition. The unit is inspected annually. Overhaul frequency is determined by operating hours and the number of starts. The unit is currently contracted through 2035.

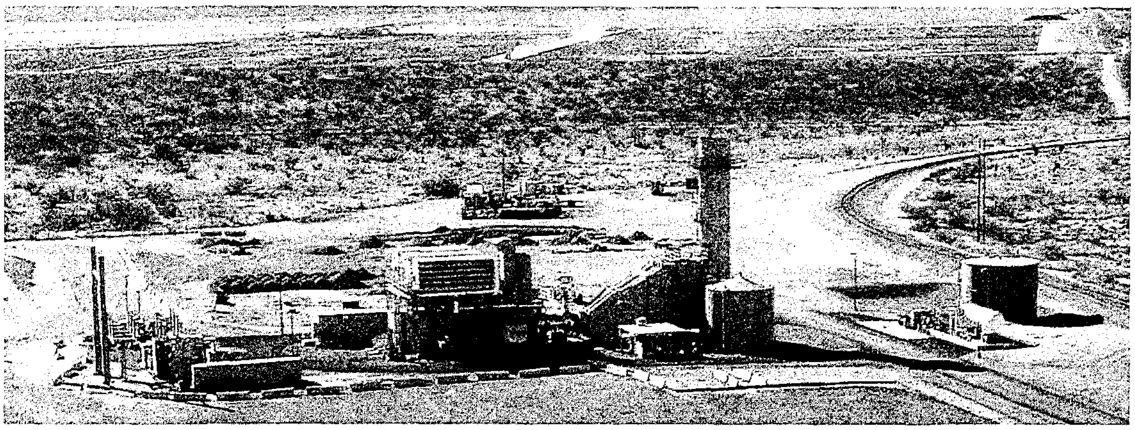

Figure 5-3 GT4

5.3 Conclusions and Recommendations

As shown in Table 5-1, AEPCO expects to operate GT2 and GT3 at slightly higher capacity factors in the future. GT4 is expected to operate at a significantly higher capacity factor.

AEPCO's proposed plan will require an increased number of starts and higher operating hours. Both events will reduce the calendar period between required overhauls and increase required capital and operating budgets over historical values. It should be noted that combustion turbine performance degrades over time between overhauls and with an increasing number of starts. The majority of this performance loss is typically recaptured during overhaul.

[5] Extended operation on FO2 is not anticipated. FO2 in tank also used to fill plant mobile equipment. This is intended to help turn over inventory and minimize degradation from long term storage.

Table 5-1 GT Historical and Projected Capacity Factor Comparison		
Unit	**Historical Average Capacity Factor 2006 - 2010**	**Projected Average Capacity Factor 2011 - EOC (end of contract)**
GT2	< 1%	2 %
GT3	< 2%	5%
GT4	10.5%	25%

Based on information obtained from the site visit, staff interviews, outage reports, and Black and Veatch's experience with other unit of similar design and vintage it is anticipated the GT2 and GT3 can continue operation to 2020 and GT4 can continue to operate through 2035 provided AEPCO continues to maintain good operations, maintenance and safety practices and expand the capital required for periodic replacement/refurbishment of the equipment.

As a minimum, AEPCO should continue to:

- Complete the planned major overhaul of GT3 in 2012.
- Perform annual borescope inspections of the unit to monitor internal conditions of the turbine.
- Perform other inspections and overhauls in accordance with OEM recommendations based on number of starts and operating hours.
- Continue routine preventive maintenance.

6.0 Major Electrical Equipment

6.1 Background and Description

The evaluation of the electrical equipment was performed for each generating unit based on discussions with AEPCO staff, review of outage reports, and observations during site tours. The results and recommendations are presented generically since common maintenance procedures and practices are utilized. Where unit specific issues were observed, these are noted.

6.1.1 Main Generators

All of the generators on site are 2 pole, 3600 rpm, hydrogen cooled machines using static type excitation systems. These generators at the present time are operated well below nameplate ratings for both real (MW) and reactive (MVar) power output.

6.1.1.1 ST2 & 3 The following practices, monitoring, and technical features were noted.

- On-line IRIS partial discharge monitoring system installed to monitor degradation in stator insulation integrity.
- Off-line IRIS partial discharge tested performed to verify on-line data and achieve more in-depth analysis (done during major outages).
- Submitted test data showed no significant insulation degradation.
- Rigorous program to maintain hydrogen coolers so they perform at or above design basis.
- Good adherence to manufacturer recommended maintenance intervals and inspections.
- No significant vibration problems have been noted.
- Known shorted turns in rotor windings; this not unusual in industry standards, especially considering the age of these machines. Flux probes are installed which will allow monitoring of this condition.
- Testing of overspeed for the turbine generator system is performed on a regular basis.
- Generator shaft grounding brush and bearing pedestal insulation monitoring is being performed.
- No observed problems with seal oil leaks (dissolved hydrogen in seal oil systems).
- Hydrogen coolers are being sent out for refurbishment as required.

6.1.1.2 ST1 & GTs. The following practices, monitoring, and technical features were noted.

- It is acknowledged that these generators are receiving a less comprehensive maintenance program due to the limited number of operating hours.
- Historically, these units have received the required maintenance.
- Significant capital expense (i.e., stator re-wind) may not be economically feasible for these units due to their age and limited runtime hours. The exception to this would be GT4 which is significantly newer than the other 4 generators.

6.1.2 Large Oil Filled Transformers

All transformers are receiving full oil analysis on a regular basis which included dissolved gas analysis and oil chemistry analysis.

6.1.2.1 ST2 Step-Up and Auxiliary Transformers. The following was noted.

- Replaced in last 5 years so that on-site spare would be available.
- Step-up transformer uses on-line Serveron dissolved gas monitor (in addition to manual gas sample analysis).
- Recent loading indicates levels well below design limits for both top oil and winding hot-spot temperatures.
- Trend for combustible gasses show no significant levels.
- Moisture in oil and dielectric withstand are within acceptable limits.
- Furan analysis was last performed in 2007.

6.1.2.2 ST3 Step-Up and Auxiliary Transformers. The following was noted.

- Step-up transformer uses on-line Severon dissolved gas monitor (in addition to manual gas sample analysis).
- Recent loading indicates levels well below design limits for both top oil and winding hot-spot temperatures.
- Trend for combustible gasses shows increases in both methane and ethane. Higher levels of these gasses indicate potential problems with high winding temperatures. The in-tank inspection performed for this transformer during the last outage indicated a cosmetic tear in the outer winding paper insulation. Continued monitoring of dissolved gasses is recommended since no on-site field repair was possible.
- Moisture in oil and dielectric withstand are within acceptable limits (these would not be contributors to increase in combustible gas levels noted above.

- Complete oil chemistry and dissolved gas analysis was performed during the last outage. No significant findings were discovered.
- A Doble Power Factor test was performed on both the transformer windings and transformer bushings. The H1 bushing had a higher power factor reading than the other bushings and should be monitored for possible increased leakage currents.

6.1.2.3 ST1 and GT1 Step-Up and Auxiliary Transformers. The plant staff is taking manual oil samples on a regular basis.

6.1.3 Medium Voltage Motors

Plant Maintenance personnel are performing required maintenance on large motors (i.e., BFP, ID Fan, FD Fan, CP, Circ. Water) as required. Activities and tasks noted as follows:

- Motors are sent out to local repair shops on a regular basis for cleaning and refurbishment during scheduled outages (i.e., Circulating Water Pump motors).
- Substantial margin had been accommodated for most of these motors (i.e. Condensate Pumps at 85% maximum load); this will allow motors to be run well below their insulation thermal design point.
- Vibration detectors in use on large machines.
- Space heater operation verified during maintenance activities.
- Hi Potential tests performed on windings during outages.
- PDA test set analysis performed during outages (offline).

6.1.4 Plant Grounding System

The above ground portions of the system appear to be in good condition. Appropriate connections to building steel and electrical equipment are in place.

6.1.5 Medium Voltage Switchgear

Overall the medium voltage switchgear appears to be in good condition for given age of equipment.

- Plant utilizes GE Magneblast vertical lift type breakers on ST2 and ST3 lineups.
- Plant contracts maintenance and refurbishment to a local company as required.
- No other operational issues noted.

6.1.6 Medium Voltage Cables

The Plant does not presently test medium voltage cable.

6.2 Conclusions and Recommendations

6.2.1 Main Generators

The following recommendations are made to ensure continued operation of the equipment to planned end of life.

- Continue with existing maintenance and inspection program.
- Monitor generator vibration levels with consideration that rotor shorted turns may exhibit increased levels, thereby requiring corrective action (re-wind of rotors).
- Be aware that reactive capability will be reduced by the proportion of turns shorted on the rotor. This is not anticipated to be an issue at present due to the high operating power factors but may pose limitations should higher reactive power support be required by the grid operator.
- Continue to perform both the online and offline partial discharge (PD) tests on the generator.
- Perform visual inspection of generator end-winding assemblies and main lead assemblies during plant outages.
- Consider performing EL-CID core loss test during outages where rotors are removed to determine any significant degradation in interlaminar stator iron insulation.

6.2.2 Large Oil Filled Transformers

The following recommendations are made to ensure continued operation of the equipment to planned end of life.

- Continue oil sampling on all large oil-filled transformers.
- Include Doble Power Factor testing for windings and bushings (if not already being performed).
- Include logging of top oil temperature and winding temperature readings from local dials to allow early detection of adverse loading trends.
- Perform Furan analysis and associated calculation of degree of polymerization (in accordance with IEEE recommended guidelines) of transformer paper to determine remaining life of insulation system.

6.2.3 Medium Voltage Motors

The Plant should continue current maintenance practices.

6.2.4 Plant Grounding System

The following testing is recommended.

- B&V recommends perform tests as outlined (see e-mail to Dave Landwerlen dated 2/21/11).
- Verify connections to below grade grid for high structures (i.e., stack and boiler building).

6.2.5 Medium Voltage Switchgear

The following testing is recommended.

- Use AC hipot in lieu of DC hipot; DC hipot stresses weakest link in equivalent series capacitor circuit and may cause failure.
- Use breaker timing device to check true "as found" condition when initially operating breaker after being in service prior to racking breaker out for testing; recommend Kelman test set (or similar).
- Verify ground shoe and bus stab finger cluster alignments are within specification.
- Verify lubricating grease meets current standards (i.e., Mobil 28 or equivalent).

6.2.6 Medium Voltage Cable

The plant is presently not doing any testing. The following testing is recommended.

- Perform VLF Tan Delta testing to determine global aging of underground cables (refer to procedure in IEEE 400).
- Perform VLF Hipot testing to determine point defects (i.e., splices and terminations) for underground cables (refer to IEEE 400).

7.0 Decommissioning Costs & Salvage

7.1 Decommissioning & Salvage Assumptions

A set of decommissioning assumptions was developed based on discussions with AEPCO corporate and plant staff. These discussions focused on safety and security requirements, known hazardous materials that would be encountered during demolition, and final site conditions.

The total cost estimate is based on traditional, multiple contracting by AEPCO and includes the following units and facilities:

- GT1 GE MS5001D gas fired combustion turbine, (ducted to ST1), and ST1 cooling tower.
- GT2 GE Frame 5N gas fired simple cycle combustion turbine.
- GT3 Westinghouse 501B2 gas fired combustion turbine.
- GT4 GE LM6000 gas and oil fired combustion turbine.
- ST2 & 3 pulverized coal boilers, common stack and separate cooling towers.
- Ash surface impoundments and coal pile.
- Common facilities and structures, and plant auxiliaries, excluding the switchyard.
- Coal unloading facility, dumper car, conveyors, and approximately 5 miles of rail loop.

A list of these general assumptions follows.

- This is an order of magnitude cost estimate with an accuracy level of +/- 35%.
- Potential decommissioning at the end of contract period as identified in Table 2-1.
- AEPCO will retain ownership of the site. AEPCO will be a good neighbor and eliminate any dangerous conditions (holes, etc.).
- A new security fence for the main plant and surface impoundment facility.
- The transmission system will remain intact including the switchyards.
- Combustion Waste Disposal facility impoundments will be capped.
- Estimate is based on a dismantling method using torches and shears other heavy equipment and not explosives.
- The non-hazardous domestic waste, such as architectural debris, will be disposed of at a disposal site located at local or regional facilities located in Huachuca City, AZ or Phoenix, AZ areas, respectively. Thirty (30) cubic yard roll-off containers will be used to transport non hazardous materials. Tipping fees are included in the estimate disposal costs for bulk disposal.

- The Plant has sufficient lay down areas for staging demolition equipment, contractors' trailers, and temporary storage and breakdown of demolished materials.
- Estimate assumes demolition to be at grade and all below grade foundations below grade and underground utilities to be abandoned in place.
- Estimate assumes that all turbine pedestals and Combustion Turbine foundations will be abandoned in place.
- The estimate assumes that all concrete will be pulverized and recycled by the demolition contractor.
- When specific equipment/material items are assumed to be scrapped, no landfill disposal cost is included.
- The estimate assumes that backfill materials are available on the site for backfilling demolished foundations and utilities.
- The estimate assumes that all scrap metal, such as: structural steel, misc. steel, conduit, cable, piping, valves and equipment, will be cut to size on site for transporting in roll-off containers and 40' trailers to Tucson Iron & Metal near Tucson. Costs for transportation are included in the scrap unit pricing. Scrap prices as quoted by Tucson Iron and Metal are based on current day March, 2011 dollar and are subject to change based on market conditions.
- Owner's indirect costs are not included.
- Removal of Switchyard, substations, and associated towers, transmission lines, buildings and roadways are not included.
- Disposal of office furniture, office equipment, and spare parts inventory is not included.
- Estimate assumes that all plant operating fuels will be removed by the owner.
- Estimate assumes that all plant systems will be de-energized, drained and tagged-out of service by the owner.
- The salvaging, resale pricing, or storage of balance of plant reusable equipment, such as pumps, is not included as the future market for these items are unknown.
- Construction power and water is assumed to be available at the site boundary.

Environmental and Hazardous Material Scope Assumptions

- The asbestos removal and disposal will be minimal and comprise of some gaskets. Asbestos will be disposed on AEPCO's onsite asbestos monofill.

- This estimate assumes that asbestos materials are not present in the PC Units, Combustion Turbines, auxiliaries or other components.
- No remediation or removal of contaminated spills, or associated plumes, is included.
- Additional environmental remediation (other than the removal of lead paint for demolition purposes and asbestos gaskets as noted) is not included in the estimate.
- Draining and disposal of transformer PCBs are not included. It is assumed that remediation/removal of PCBs is not required and that the 85 gallons of PCB contaminated oil currently located on site will be removed prior to site decommissioning.
- The estimate assumes that the Demolition Contractor will properly remove and dispose/recycle all structures and equipment containing lead paint.
- Batteries will be disposed of at the Clean Harbor disposal facility located in Phoenix, Arizona.
- Environmental testing, removal, and/or disposal of existing fuels are not included.
- The estimate assumes that all fuel oil tanks will be drained and swabbed for residual oil to permit shearing of steel during the demolition process.
- Estimate assumes that all surplus coal will be removed from the coal storage piles and bunkers prior to demolition activities.
- Base of coal pile will be excavated to a depth of approximately 3 feet and disposed off site and transported to the Butterfield hazardous waste land field near Tucson. The excavated 3 foot dept area will be backfilled /capped and graded with imported fill material.
- Ash surface impoundments and the Scrubber waste surface impoundment will be excavated to a depth of 3 feet and disposed off site and transported to the Butterfield hazardous waste land field near Phoenix, Arizona. The excavated 3 foot depth area will be backfilled /capped and graded with imported fill material[6]
- Existing monitoring wells are assumed to be sufficient and therefore additional monitoring wells or equipment is not included in this estimate.

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[6] AEPCO's permit application for the new facility only indicates that AEPCO will propose specific closure activities at the time the plant is decommissioned. AEPCO indicated the scrubber surface impoundments most likely will be capped and that the ash surface impoundments and evaporation surface impoundments would be dewatered and capped. The AEPCO closure plan to the state would have to be approved for implementing. The Black & Veatch assumption is conservative. Excavation and backfill costs are called out separately in the detailed cost estimate included in Appendix A.

7.2 Decommissioning & Salvage Costs

Economic assumptions are based on regional cost estimates and expressed in March 2011 dollars and do not include escalation. Direct and indirect cost assumptions are shown below.

Direct Cost Assumptions:

- Wage rates are based on labor rates from Tucson, Arizona during the first quarter of 2011.
- Direct costs include the costs associated with equipment rental, demolition and all contractor services except as noted.
- Demolition costs for the estimate include all Contractor overhead, staff, indirect costs, and profit.
- Federal, State and local environmental permitting and licensing fees are not included.
- Contingency costs are included as an allowance for site unknowns.

Indirect Cost assumptions

- Electricity, water, temporary toilets, and fuels used during demolition are included in this cost estimate. Contractor's General liability insurance is included.

7.2.1 Decommissioning Cost

The total estimated cost to decommission the Apache Station is approximately 61 million dollars ($61) A detailed breakdown of estimated decommissioning costs are shown in spreadsheets included in Appendix A. Decommissioning assumptions was developed based on discussions with AEPCO corporate and plant staff.

7.2.2 Salvage Value

Scrap values used in this study are based on discussions with Tucson Iron & Metal Company and reflect March 2011 values. Prices include the cost of transportation from the demolition site to the recycling plant.

Table 7-1 Scrap Value Assumptions

Item	Value
Steel – Structural	$235 / ton
Steel - Mixed	$220 / ton
Aluminum	$0.80 / lb

7.2.3 GT1

GT1 is currently contracted through 2020. Since GT1 is removed from ST1 and only connected by ductwork, this unit could be decommissioned and removed separately. If desired, the ductwork could be blanked off to allow continued operation of ST1.

Due to the relatively small size and general location near the front of the site, it is anticipated that the unit would be dissembled using torches, sheer, and heavy equipment.

7.2.4 GT2

GT2 is currently contracted through 2020. GT2 stands independently and can be left in place or removed at AEPCO's discretion at a later date. Due to the relatively small size and close proximity to ST2, it is anticipated that the unit would be dissembled manually and scrap removed by truck.

7.2.5 GT3

GT3 currently contracted through 2020. GT3 stands independently and can be left in place or removed at AEPCO's discretion at a later date. Due to the relatively small size and general location near the front of the site, it is anticipated that the unit would be dissembled manually and scrap removed by truck.

7.2.6 GT4

GT4 is currently contracted through 2035. GT4 stands independently and can be left in place or removed at AEPCO's discretion at a later date. Due to the relatively small size, it is anticipated that the unit would be dissembled manually and scrap removed by truck.

7.2.7 ST1

ST1 is currently contracted through 2020. ST1 and its cooling tower can be left in place or removed at AEPCO's discretion at a later date. Due its location it is anticipated that the unit will be disassembled manually and scrap removed by truck..

7.2.8 ST2 & ST3

ST2 and ST3 are currently contracted through 2035. The units are expected to be removed simultaneously and in conjunction with the Combustion Waste Disposal Facility, coal yard, rail lines, and other miscellaneous structures.

7.3 Decommissioning Cost Estimates

The approximate decommissioning costs by unit are shown in Table 7-2. Costs assume March 2011 dollars. A more detailed breakdown of the decommissioning costs can be found in Appendix A.

Table 7-2 Estimated Decommissioning Costs By Unit	
Unit	Decommissioning Cost
GT1	$736,800
ST1	$2,197,400
ST2	$27,688,800
ST3	$27,691,000
GT2	$675,500
GT3	$817,600
GT4	$1,220,100
Total	$61,027,200

7.4 Salvage Estimates

The approximate salvage value of site equipment by material and by unit is shown in Tables 7-3 and 7-4, respectively. Costs assume March 2011 dollars. A more detailed breakdown of the salvage values can be found in Appendix A.

Table 7-3 Estimated Salvage Value By Material	
Item	**Value**
Rail	$310,200
Concrete & Rebar	$633,600
Architecture & Associated Metals	$1,217,100
Piping, Valves, Hangers & Supports	$505,300
Mechanical Equipment	$4,300,400
Electrical Equipment	$7,415,600
Total Estimated Salvage Value	$14,382,200

Table 7-4 Estimated Salvage Value By Unit	
Item	**Value**
GT1	$719,200
ST1	$2,157,300
ST2	$4,314,400
ST3	$4,314,700
GT2	$719,200
GT3	$719,200
GT4	$1,438,200
Total Estimated Salvage Value	$14,382,200

Appendix A Decommissioning & Salvage Details

Detailed decommissioning and salvage assumptions are provided in the following spreadsheets.

Construction Indirects & Services

Not included.

Column Descriptions and Functions

Cost Code: Area for inserting owner's cost or unit of property codes.

Level 1. Description: Describes categories such as Site work, Concrete, Piping.

Level 2. Description: Provides the line item description within the Sitework, concrete, Piping categories.

Quantity: Provide the quantities for each line item.

UM or Unit of Measure: shows the Unit of measure for the list quantities, such as: CY= Cubic Yards, SY = Square Yards, et

Unit Manhours (MH/UM); Shows the unit manhour rate to perform for one item shown in the Quantity column.

Wage Rate: The Manhour Labor Dollar rates or cost or each manhour.

Demolition Equipment & Material Costs

Dumpster & Disposal Fee: Costs for dumpsters and disposal of hazardous and non-hazardous debris at dump sites or lan

Total Labor: Total labor costs for each line item.

Total Manhours: Total manhours for each line item.

Estimate Scrap Value: Estimated salvage value of steel, copper,and aluminum.

AEPCO Apache Station Decommissioning

COUNTRY / REGION: Arizona
B&V PROJECT #: 168868
PLANT TYPE: PC Coal and Combustion Turbines
CLIENT / OWNER: AEPCO
ESTIMATE TYPE: Order of Magnitude
PROJECT ESTIMATOR: Ron Fields
FILENAME: Rev.1 5/10/2011

Cost Code	Level 1 Description	Level 2 Description	Quantity	UM	Total	Scrap Unit price	Estimated Scrap Value	Unit 1 Gas Fired Boiler	Unit 2 195 MW PC	Unit 3 195 MW PC	GT 1 GEMS5001D Combined cycle	GT 2 GE 5 N Simple Cycle	GT 3 Westinghouse 501B2 Simple Cycle	GT 4 GE LM6000 Simple Cycle
		Earthwork & Site Work Demolition												
,000000	Site work	Excavation - power block and outlying areas at grade (minimal)	65,000	CY	$231,075		$0	$34,661	$69,323	$69,323	$11,554	$11,554	$11,554	$23,108
,000000	Site work	Backfill - power block and outlying areas	65,000	CY	$1,018,875		$0	$152,831	$305,663	$305,663	$50,944	$50,944	$50,944	$101,888
,000000	Site work	Finish grading and seeding Power block areas and all ponds	185,700	SY	$121,634		$0	$18,245	$36,490	$36,490	$6,082	$6,082	$6,082	$12,163
,000000	Site work	Push in berm walls - cooling tower blow-dn pond	8,400	CY	$26,838		$0	$0	$13,419	$13,419	$0	$0	$0	$0
2000000	Site work	Railroad approx. 5 miles (assumes code 150 rail)	1320	TN	$142,560	$235	$310,200	$0	$71,280	$71,280	$0	$0	$0	$0
,000000	Site work	Excavate Ash pond 3' and dispose of debris (Approx. 185 acres)	907,523	CY	$16,335,414		$0	$0	$8,167,707	$8,167,707	$0	$0	$0	$0
,000000	Site work	Backfill Ash pond 3'	907,523	CY	$14,225,423		$0	$0	$7,112,712	$7,112,712	$0	$0	$0	$0
,000000	Site work	Excavate ~ coal Strorage area and run-off pond 3' and dispose of debris (~12 acres)	62,000	CY	$1,252,090		$0	$0	$626,045	$626,045	$0	$0	$0	$0
,000000	Site work	Backfill coal storage area and run-off pond	62,000	CY	$971,850		$0	$0	$485,925	$485,925	$0	$0	$0	$0
,000000	Site work	Install new securiy premeter fence	25,000	LF	$750,000		$0	$112,500	$225,000	$225,000	$37,500	$37,500	$37,500	$75,000
,000000	Site work	Onsite paved Roads & Parking (22,000 SY)	22,000	SY	$109,900		$0	$16,485	$32,970	$32,970	$5,495	$5,495	$5,495	$10,990
		Subtotal Earthwork Demolition			**$35,185,659**		**$310,200**	**$334,723**	**$17,146,533**	**$17,146,533**	**$111,574**	**$111,574**	**$111,574**	**$223,148**
		Concrete Demolition												
1000000	Concrete	Concrete - PC Units 1, 2, and 3 Power Block	27,500	CY	$687,500		$0	$233,750	$226,875	$226,875	$0	$0	$0	$0
1000000	Concrete	Outlying Structures / Site building slabs	2,500	CY	$62,500		$0	$9,375	$18,750	$18,750	$3,125	$3,125	$3,125	$6,250
1000000	Concrete	Rebar & embeds scrap	2,880	TN	$129,600	$220	$633,600	$44,064	$42,768	$42,768	$0	$0	$0	$0
			30,000.00											
		Subtotal Concrete Demolition at Grade			**$879,600**		**$633,600**	**$287,189**	**$288,393**	**$288,393**	**$3,125**	**$3,125**	**$3,125**	**$6,250**
		Arch & Metals Demolition												
2000000	Arch & Metals	Structure- columns	339	TN	$48,411	$235	$79,609	$21,785	$13,313	$13,313	$0	$0	$0	$0
2000000	Arch & Metals	Structure - Beams	416	TN	$47,541	$235	$97,741	$21,393	$13,074	$13,074	$0	$0	$0	$0
2000000	Arch & Metals	Structure - Boiler columns	236	TN	$26,887	$235	$55,538	$12,099	$7,394	$7,394	$0	$0	$0	$0
2000000	Arch & Metals	Structure - Boiler Girders	204	TN	$23,119	$235	$47,823	$10,403	$6,358	$6,358	$0	$0	$0	$0
2000000	Arch & Metals	Structure - SDAS columns	49	TN	$9,095	$235	$11,603	$0	$4,547	$4,547	$0	$0	$0	$0
2000000	Arch & Metals	Structure - SDAS girders	43	TN	$6,071	$235	$10,216	$0	$3,035	$3,035	$0	$0	$0	$0
2000000	Arch & Metals	Structure - SDAS Booster Pump building	2000	SF	$3,000	$0	$0	$0	$1,500	$1,500	$0	$0	$0	$0
2000000	Arch & Metals	Structure - Control Building	3400	SF	$10,200	$0	$0	$1,530	$3,060	$3,060	$510	$510	$510	$1,020
2000000	Arch & Metals	Structure - Fire Safety Building	3800	SF	$5,700	$0	$0	$855	$1,710	$1,710	$285	$285	$285	$570
2000000	Arch & Metals	Structure - Lube Oil Storage	1100	SF	$1,650	$0	$0	$743	$454	$454	$0	$0	$0	$0
2000000	Arch & Metals	Structure - Coal Handing Equipment Building	2500	SF	$4,250	$0	$0	$0	$2,125	$2,125	$0	$0	$0	$0
2000000	Arch & Metals	Structure - Maintenance Shop	9400	SF	$14,100	$0	$0	$2,115	$4,230	$4,230	$705	$705	$705	$1,410
2000000	Arch & Metals	Structure - Warehouse	20300	SF	$30,450	$0	$0	$4,568	$9,135	$9,135	$1,523	$1,523	$1,523	$3,045
2000000	Arch & Metals	Structure - Admin Building	11300	SF	$33,900	$0	$0	$5,085	$10,170	$10,170	$1,695	$1,695	$1,695	$3,390
2000000	Arch & Metals	Structure - Coal maint. building	2800	SF	$4,760	$0	$0	$0	$2,380	$2,380	$0	$0	$0	$0
2000000	Arch & Metals	Structure - Crusher House	4200	SF	$7,140	$0	$0	$0	$3,570	$3,570	$0	$0	$0	$0
2000000	Arch & Metals	Structure - Limestone Handling building	1500	SF	$2,550	$0	$0	$0	$1,275	$1,275	$0	$0	$0	$0
2000000	Arch & Metals	Metal Siding Scrap	80	TN	$3,750	$220	$17,600	$825	$1,463	$1,463	$0	$0	$0	$0
2000000	Arch & Metals	Outlying Structures - Buildings / Structural Steel	200	TN	$23,250	$235	$47,000	$3,488	$6,975	$6,975	$1,163	$1,163	$1,163	$2,325
2000000	Arch & Metals	Mics steel, Handrail, ladders, decking, grating	1700	TN	$229,650	$500	$850,000	$34,448	$68,895	$68,895	$11,483	$11,483	$11,483	$22,965
2000000	Arch & Metals	Bulk Archietectual debris disposal	1	LS	$500,000	$0	$0	$75,000	$150,000	$150,000	$25,000	$25,000	$25,000	$50,000
							$0							
		Subtotal Arch & Metals			**$1,035,473**		**$1,217,129**	**$194,336**	**$314,682**	**$314,682**	**$42,363**	**$42,363**	**$42,363**	**$84,726**
		Piping, Valves, Hangers/Supports Demolition												
3000000	Piping	Pipe-AG-Large Bore and Small bore	2,150	TN	$242,625	$235	$505,250	$36,394	$72,788	$72,788	$12,131	$12,131	$12,131	$24,263
3000000	Piping	Piping - cap-off below grade and abandoned in place	1	LS	$9,015		$0	$1,352	$2,705	$2,705	$451	$451	$451	$902
		Subtotal Piping & Insl	**2,151.00**	**LF**	**$251,640**		**$505,250**	**$37,746**	**$75,492**	**$75,492**	**$12,582**	**$12,582**	**$12,582**	**$25,164**

Cost Code	Level 1 Description	Level 2 Description	Quantity	UM	Total	Scrap Unit price	Estimated Scrap Value	Unit 1 Gas Fired Boiler	Unit 2 195 MW PC	Unit 3 195 MW PC	GT 1 GEMS5001D Combined cycle	GT 2 GE 5 N Simple Cycle	GT 3 Westinghouse 501B2 Simple Cycle	GT 4 GE LM6000 Simple Cycle
		Mechanical Equipment Demolition												
4000000	Mech Equip	ST1 Steam Turbine Generator	167	TN	$22,545	$350	$58,450	$0	$0	$0	$22,545	$0	$0	$0
4000000	Mech Equip	ST2 Steam Turbine Generator	341	TN	$45,968	$350	$119,175	$0	$45,968	$0	$0	$0	$0	$0
4000000	Mech Equip	ST3 Steam Turbine Generator	341	TN	$47,568	$350	$119,175	$0	$0	$47,568	$0	$0	$0	$0
4000000	Mech Equip	GT1 Combsution Turbine Generator	165	TN	$119,625	$350	$57,750	$0	$0	$0	$119,625	$0	$0	$0
4000000	Mech Equip	GT2 Combsution Turbine Generator	136	TN	$98,070	$350	$47,600	$0	$0	$0	$0	$98,070	$0	$0
4000000	Mech Equip	GT3 Combsution Turbine Generator	264	TN	$190,080	$350	$92,400	$0	$0	$0	$0	$0	$190,080	$0
4000000	Mech Equip	GT4 Combsution Turbine Generator	200	TN	$144,000	$350	$70,000	$0	$0	$0	$0	$0	$0	$144,000
4000000	Mech Equip	ST1,2 &3 Boiler Drum	446	TN	$50,127	$235	$104,709	$11,028	$19,549	$19,549	$0	$0	$0	$0
4000000	Mech Equip	ST2,3 Downcomers	283	TN	$31,809	$235	$66,445	$0	$15,904	$15,904	$0	$0	$0	$0
4000000	Mech Equip	ST1, 2, &3 Waterwalls	848	TN	$95,400	$235	$199,280	$20,988	$37,206	$37,206	$0	$0	$0	$0
4000000	Mech Equip	ST1, 2, & 3 Economizer	603	TN	$67,795	$235	$141,616	$14,915	$26,440	$26,440	$0	$0	$0	$0
4000000	Mech Equip	ST1, 2, & 3 Pendants	572	TN	$64,312	$235	$134,342	$14,149	$25,082	$25,082	$0	$0	$0	$0
4000000	Mech Equip	ST1, 2, & 3 Reheater	540	TN	$60,797	$235	$126,998	$13,375	$23,711	$23,711	$0	$0	$0	$0
4000000	Mech Equip	Boilers Superheat sections and casings	2,090	TN	$235,125	$235	$491,150	$51,728	$91,699	$91,699	$0	$0	$0	$0
4000000	Mech Equip	Ball Mills	800	TN	$90,000	$235	$188,000	$0	$45,000	$45,000	$0	$0	$0	$0
4000000	Mech Equip	PA Fans	20	TN	$2,194	$235	$4,583	$0	$1,097	$1,097	$0	$0	$0	$0
4000000	Mech Equip	FD Fans	114	TN	$12,975	$235	$26,790	$0	$6,488	$6,488	$0	$0	$0	$0
4000000	Mech Equip	ID Fans	190	TN	$30,225	$235	$44,650	$0	$15,113	$15,113	$0	$0	$0	$0
4000000	Mech Equip	GRFan	60	TN	$6,750	$235	$14,100	$0	$3,375	$3,375	$0	$0	$0	$0
4000000	Mech Equip	Crusher/Dryers	20	TN	$2,378	$235	$4,653	$0	$1,189	$1,189	$0	$0	$0	$0
4000000	Mech Equip	Feeders	30	TN	$3,375	$235	$7,050	$0	$1,688	$1,688	$0	$0	$0	$0
4000000	Mech Equip	Coal Bunkers	88	TN	$10,057	$235	$20,695	$0	$5,029	$5,029	$0	$0	$0	$0
4000000	Mech Equip	Cranes	100	TN	$11,250	$235	$23,500	$0	$5,625	$5,625	$0	$0	$0	$0
4000000	Mech Equip	Boiler feed Pumps	54	TN	$6,075	$235	$12,690	$0	$3,038	$3,038	$0	$0	$0	$0
4000000	Mech Equip	BFP Motor	42	TN	$4,725	$235	$9,870	$0	$2,363	$2,363	$0	$0	$0	$0
4000000	Mech Equip	Condensate Pump	10	TN	$1,448	$235	$2,397	$0	$724	$724	$0	$0	$0	$0
4000000	Mech Equip	Condensate motor	6	TN	$1,603	$235	$1,363	$0	$801	$801	$0	$0	$0	$0
4000000	Mech Equip	Circ. Water Pumps	78	TN	$11,115	$235	$18,330	$0	$5,558	$5,558	$0	$0	$0	$0
4000000	Mech Equip	CW Motors	40	TN	$4,650	$235	$9,400	$0	$2,325	$2,325	$0	$0	$0	$0
4000000	Mech Equip	Condensers	585	TN	$65,963	$235	$137,475	$0	$32,981	$32,981	$0	$0	$0	$0
4000000	Mech Equip	Centac Air Compressors	32	TN	$3,773	$235	$7,567	$0	$1,886	$1,886	$0	$0	$0	$0
4000000	Mech Equip	Centac Motors	23	TN	$2,715	$235	$5,358	$0	$1,358	$1,358	$0	$0	$0	$0
4000000	Mech Equip	Air Heaters	2,500	TN	$281,400	$235	$587,500	$0	$140,700	$140,700	$0	$0	$0	$0
4000000	Mech Equip	Ductwork	127	TN	$14,635	$235	$29,840	$0	$7,318	$7,318	$0	$0	$0	$0
4000000	Mech Equip	Breaching and supports	2,000	TN	$225,600	$235	$470,000	$0	$112,800	$112,800	$0	$0	$0	$0
4000000	Mech Equip	Scubber Towers	211	TN	$24,346	$235	$49,603	$0	$12,173	$12,173	$0	$0	$0	$0
4000000	Mech Equip	AFT tank	42	TN	$4,994	$235	$9,805	$0	$2,497	$2,497	$0	$0	$0	$0
4000000	Mech Equip	Precipitators	1,900	TN	$214,340	$235	$446,500	$0	$107,170	$107,170	$0	$0	$0	$0
4000000	Mech Equip	Stack - Common Chimney	247	TN	$27,788	$235	$58,045	$0	$13,894	$13,894	$0	$0	$0	$0
4000000	Mech Equip	Raw Water Tank	116	TN	$13,050	$235	$27,260	$0	$6,525	$6,525	$0	$0	$0	$0
4000000	Mech Equip	Acid Tanks	10	TN	$1,125	$235	$2,350	$0	$563	$563	$0	$0	$0	$0
4000000	Mech Equip	Fly Ash / Bottom Ash Systems	250	TN	$28,125	$235	$58,750	$0	$14,063	$14,063	$0	$0	$0	$0
4000000	Mech Equip	Coal handling system	350	TN	$39,375	$235	$82,250	$0	$19,688	$19,688	$0	$0	$0	$0
4000000	Mech Equip	Fuel Oil tanks	450	TN	$50,625	$235	$105,750	$0	$20,250	$20,250	$0	$0	$10,125	$0
4000000	Mech Equip	Condensate tank	22	TN	$2,775	$235	$5,170	$0	$1,388	$1,388	$0	$0	$0	$0
4000000	Mech Equip	Cooling Towers	3	EA	$88,460	$0	$0	$29,486	$29,486	$29,488	$0	$0	$0	$0
		Subtotal Mech Equipment Demolition			$2,561,126		$4,300,383	$155,668	$909,705	$911,307	$142,170	$98,070	$200,205	$144,000
		Electrical Demolition												
5000000	Electrical	Copper and Aluminum bus	50	TN	$45,225	$7,200	$360,000	$4,523	$11,306	$11,306	$4,523	$4,523	$4,523	$4,523
5000000	Electrical	Turbine/Generators Electrical & Auxiliaries	66	TN	$3,570	$1,600	$105,600	$357	$893	$893	$357	$357	$357	$357
5000000	Electrical	Transformers - main, and Aux, plus others	630	TN	$30,650	$1,000	$630,000	$3,065	$7,663	$7,663	$3,065	$3,065	$3,065	$3,065
5000000	Electrical	BOP Electrical equipment, switchgerar, Motor Contro centers, cabiners, panels	650	TN	$29,850	$1,600	$1,040,000	$2,985	$7,463	$7,463	$2,985	$2,985	$2,985	$2,985
5000000	Electrical	Cable - copper	600	TN	$173,300	$7,200	$4,320,000	$17,330	$43,325	$43,325	$17,330	$17,330	$17,330	$17,330
5000000	Electrical	Conduit & Cable Tray	600	TN	$135,600	$1,600	$960,000	$13,560	$33,900	$33,900	$13,560	$13,560	$13,560	$13,560
		Subtotal Electrical Demolition			$418,195		$7,415,600	$41,820	$104,549	$104,549	$41,820	$41,820	$41,820	$41,820
		Demolition Equipment												
5000000	Equipment	Small Tools	1	LS	$251,400	$0	$0	$37,710	$75,420	$75,420	$12,570	$12,570	$12,570	$25,140
5000000	Equipment	Loader	16	MO	$400,000	$0	$0	$60,000	$120,000	$120,000	$20,000	$20,000	$20,000	$40,000
5000000	Equipment	150 T crane	16	MO	$720,000	$0	$0	$108,000	$216,000	$216,000	$36,000	$36,000	$36,000	$72,000
5000000	Equipment	Excavator	16	MO	$1,760,000	$0	$0	$264,000	$528,000	$528,000	$88,000	$88,000	$88,000	$176,000
5000000	Equipment	SkidSteer	16	MO	$96,000	$0	$0	$14,400	$28,800	$28,800	$4,800	$4,800	$4,800	$9,600
5000000	Equipment	man Lift	16	MO	$288,000	$0	$0	$43,200	$86,400	$86,400	$14,400	$14,400	$14,400	$28,800
		Subtotal Equipment			$3,515,400			$527,310	$1,054,620	$1,054,620	$175,770	$175,770	$175,770	$351,540
		Subtotals			$43,847,092		$14,382,162	$1,578,791	$19,893,954	$19,895,556	$529,403	$485,303	$587,438	$876,647
					Weighted % of direct costs			3.60%	45.37%	45.37%	1.21%	1.11%	1.34%	2.00%
	Indirect Costs													
		Site Demolition Permits and Fee (allowance)			$20,000			$720	$9,074	$9,075	$241	$221	$268	$400
		Demolition Contractor's Overhead and Profit			$5,261,651			$189,455	$2,387,274	$2,387,467	$63,528	$58,236	$70,493	$105,198
		Demolition Contractor's Staff			$1,727,213			$62,191	$783,657	$783,720	$20,854	$19,117	$23,140	$34,533
		Continegency 20%			$10,171,191			$366,231	$4,614,792	$4,615,164	$122,805	$112,576	$136,268	$203,355
		Total Project CostsFor Demoliton at Grade (Does not include deduct of scrap value)			$61,027,147		$14,382,162	$2,197,389	$27,688,752	$27,690,981	$736,833	$675,453	$817,607	$1,220,132
		Scrap Pricing spread percentage same as direct cost allocations.						$2,157,324	$4,314,324	$4,314,684	$719,108	$719,108	$719,108	$1,438,216

Equipment Weights (lbs)

Equiment / Structure Description	ST2	ST3	ST1	GT1	GT2	GT3	Totals LBS	Total Tons
Turbine/Generator	681,000	681,000	334000	330000	272000	528000	2,826,000	1,413
Electrical						122000	122,000	61
Auxiliaries						10500	10,500	5
Boiler Drum	311,009	311,009	269,121				891,138	446
Downcomers	282,744	282,744	0				565,488	283
waterwalls	703,201	703,201	288,897				1,695,298	848
Economizer	204,375	204,375	796,492				1,205,242	603
Pendants	446,667	446,667	250,000				1,143,333	572
Reheater	483,333	483,333	114,167				1,080,833	540
Boiler Super Heat sections and casings	1,732,000	1,732,000	715000				4,179,000	2,090
								0
Rebar and embeds	2,880,000	2,880,000					5,760,000	2,880
								0
								0
								0
Transformers (dry) main and aux.	370,000	370,000	188000	33000	60000	139000	1,160,000	580
Others	50,000	50,000					100,000	50
Copper and Alumnum bus	30,000	30,000	10,000	10,000	10,000	10,000	100,000	50
Misc. Electrical and Controls	700,000	600,000					1,300,000	650
Electrical Cable copper	400,000	400,000	100,000	100,000	100,000	100,000	1,200,000	600
Conduit & Tray	500,000	500,000	50,000	50,000	50,000	50,000	1,200,000	600
								0
Pulverizers	unknown	unknown						0
Ball Mills	800,000	800,000					1,600,000	800
PA Fans	19,500	19,500					39,000	20
FD Fans	114,000	114,000					228,000	114
ID Fans	190,200	190,200					380,400	190
GRFan	60,000	60,000					120,000	60
Crusher/Dryers	19,800	19,800					39,600	20
Feeders	30,000	30,000					60,000	30
Coal Bunkers	88,063	88,063					176,126	88
Cranes	100,000	100,000					200,000	100
Boiler feed Pumps	54,000	54,000					108,000	54
BFP Motor	42,000	42,000					84,000	42
Condensate Pump	10,200	10,200					20,400	10
Condensate motor	5,800	5,800					11,600	6
Circ. Water Pumps	78,000	78,000					156,000	78
CW Motors	40,000	40,000					80,000	40
Condensers	585,000	585,000					1,170,000	585
Centac Air Compressors	32,200	32,200					64,400	32
Centac Motors	22,800	22,800					45,600	23
Air Heaters	2,500,000	2,500,000					5,000,000	2,500
							0	0
Ductwork	126,979	126,979					253,958	127
Balance of Ductwork/Breeching	2,000,000	2,000,000					4,000,000	2,000
Scrubber towers	211,076	211,076					422,153	211
AFT Tank	41,724	41,724					83,449	42
Fly Ash System							500,000	250
Coal Handling System							700,000	350
								0
								0
Structures	No Calc.	No Calc.		No Calc.	No Calc.	No Calc.		0
columns	651,480		26,040				677,520	339
Beams	573,600		258,240				831,840	416
Boiler columns	268,800		203,860				472,660	236
Boiler Girders	156,800		250,200				407,000	204
SDAS columns	98,750						98,750	49
SDAS girders	86,945						86,945	43
Misc Steel, ladders, grating, handrails, decking	1,700,000	1,700,000					3,400,000	1,700
								0
Precipitators	1,900,000	1,900,000					3,800,000	1,900
								0
Tanks								0
Raw water	232,478	Incl.					232,478	116
Acid	18,653	incl.					18,653	9
Fuel Oil	121,166	Incl.					121,166	61
Fuel Oil	777,170	incl.					777,170	389
Condensate	44,899	incl.					44,899	22
Stack Liner	246,796	246,796					493,591	247
								0
Piping and valves	2,300,000	2,000,000					4,300,000	2,150
Railroad - Rails, assume code 150 rail - ~ 5 Miles							2,640,000	1,320
Pre-engineered metal siding and roofs							160,000	80
Pre-engineered Structural Steel							400,000	200
Total	26,123,208	22,692,467	3,854,016	523,000	492,000	959,500	59,044,191	29,522

Estimated Scrap Values

The estimated scrap values are based on Tucson Iron & Metal, Tucson, Arizona present day March 2011 values
Prices include transportation of scrap from demo site to recycling plant.

	2011	U.S. Average 2004
Steel-Structural	$235.00 TN	$45.00 TN
Steel- Mixed	*$220.00 TN*	$45.00 TN
Aluminum	0.8 LB	$0.35 LB
Copper	$3.60 LB	$0.50 LB
Nickle	0	$0.60 LB
Stainless Steel	0	$0.30 LB

EXHIBIT
PS-2

Arizona Electric Power Cooperative, Inc.

Schedule of Production Plant Depreciation Rates and Net Decommissioning Amortization
2012 Rate Case with Test Year 12 months ended 12/31/2011

1. Depreciation Rates

A. Rates for Production Units & Additions prior to 12/31/2013 (1)

	Proposed Rates	*Current Rates*
Unit ST1	**2.0025%**	*3.100%*
Unit ST2	**2.1298%**	*1.340%*
Unit ST3	**2.3278%**	*1.413%*
Unit IC1	**2.2385%**	*3.000%*
Unit IC2	**-0.1037%**	*3.000%*
Unit IC3	**2.0359%**	*3.000%*
Unit GT4	**3.1979%**	*3.000%*

Note: These Proposed Depreciation Rates remain unchanged through the end life of the Production Units, as defined by the Black & Veatch study

B. Rates for Production Units & Additions after 12/31/2013 (1)

Production Unit Additions in-service after 12/31/2013 will be depreciated over the Remaining Life of the applicable Production Unit by vintage year, the Depreciation Rate formula will be calculated as follows:

Step 1 - End Life Date of Production Unit minus Current Year = Remaining Life
Step 2 - 100% divided by Remaining Life = Depreciation Rate for that specific vintage year

(1) Subject to implementation date of new rates

2. Net Decommissioning Costs (as detailed in the Black & Veatch study)

	Net Decommissioning	Recovery Period	Proposed Annual Amortization
Unit ST1	40,100.00	22 years	**1,822.73**
Unit ST2	21,817,676.50	22 years	**991,712.57**
Unit ST3	21,819,576.50	22 years	**991,798.93**
Unit IC1	17,600.00	22 years	**800.00**
Unit IC2	(43,700.00)	22 years	**(1,986.36)**
Unit IC3	98,400.00	22 years	**4,472.73**
Unit GT4	(218,100.00)	22 years	**(9,913.64)**
	43,531,553.00		**1,978,706.95**

Net Decommissioning Costs as detailed in the Black & Veatch study equals the following:

a.) Decommissioning Costs	*61,027,200.00*
b). Salvage Value	*(14,382,200.00)*
c). Asset Retirement Obligation SFAS 143 Previously recovered by AEPCO	*(3,113,447.00)*
	43,531,553.00

B

DIRECT TESTIMONY OF GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

GENERAL RATES APPLICATION

July 2012

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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 administering 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 those 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 the R14-2-103.B Schedules A-H which have been filed in support of AEPCO's rate application.

INTRODUCTION AND SUMMARY OF REQUESTS

Q. Mr. Pierson, before discussing those schedules, please summarize AEPCO's reasons for filing this rate case.

A. Although we have several reasons, its primary purpose is to update AEPCO's depreciation rates as required by Rural Utilities Service ("RUS") guidelines. As background, in the rate case which led to Decision No. 68071, AEPCO presented a depreciation study which extended the estimated useful lives of Steam Units 2 and 3 from 2020 to 2035. This life extension study and its resulting lower depreciation rates reduced costs in that case's test year by almost $1.5 million. However, having departed from its "standard" rates, the RUS requires that AEPCO's revised depreciation rates be periodically re-evaluated and implemented. In compliance with that requirement, we commissioned another depreciation study, as described in Mr. Scott's testimony. Commission rules (A.A.C. R14-2-102.C.1) provide that revised depreciation rates may only be authorized in a rate application filed in accordance with the requirements of R14-2-103. Therefore, because a rate case is required to implement the depreciation changes discussed by Mr. Scott and required by RUS, we also performed a broader revenue requirements study to take into account changes in other expenses and revenues in the calendar 2011 test year. So, this filing seeks to (1) implement revised depreciation rates and, as well, (2) lower AEPCO's overall revenue requirements.

Q. Please summarize AEPCO's requests.

A. As a result of our revenue requirements study, AEPCO is asking that the Commission approve a revenue decrease of $4.5 million or an overall 2.92% decrease in revenue requirements. That average decrease, however, is actually a blend of a 1.30% decrease in revenues from its all-requirements members and a 3.12% decrease in revenues from its partial-requirements members.

AEPCO also recommends that the Commission continue to approve specific rates for its members based upon the cost causation principles that were used and approved in our last rate proceeding (Docket No. E-01773-09-0472, Decision No. 72055), as amended in certain respects by Decision No. 72735. We also propose some modifications to the Purchased Power Fuel Adjustor Clause ("PPFAC") which will be discussed later in my testimony.

The following summarizes present and proposed rate structures:

	Present Rates	**Proposed Rates**
Collective All-Requirements Members ("CARM"):		
Fixed Charge[(1)]	$273,334/Month	$280,598/Month
O&M Charge[(1)]	$414,019/Month	$458,175/Month
Energy Rates:		
Base Resources	$0.03132/kWh	$0.02921/kWh
Other Existing Resources	$0.05300/kWh	$0.04795/kWh

(1) Apportioned between the all-requirements members on the basis of each CARM's load ratio share of its 12-month average demand compared to the total CARMs' 12-month average demand.

Partial-Requirements Members ("PRM"):

Mohave Electric Cooperative ("MEC"):		
Fixed Charge	$835,756/Month	$856,355/Month
O&M Charge	$1,274,882/Month	$1,419,059/Month
Energy Rates:		
Base Resources	$0.03191/kWh	$0.02894/kWh
Other Existing Resources	$0.05852/kWh	$0.05437/kWh
Sulphur Springs Valley Electric Cooperative ("SSVEC"):		
Fixed Charge	$740,041/Month	$758,281/Month
O&M Charge	$1,128,876/Month	$1,256,541/Month
Energy Rates:		
Base Resources	$0.03205/kWh	$0.02938/kWh
Other Existing Resources	$0.05742/kWh	$0.0.05109/kWh
TRICO Electric Cooperative ("TRICO"):		
Fixed Charge	$710,367/Month	$743,828/Month
O&M Charge	$764,465/Month	$859,840/Month
Energy Rates:		
Base Resources	$0.03214/kWh	$0.02947/kWh
Other Existing Resources	$0.05747/kWh	$0.04219/kWh

In relation to the current energy rates stated above, the total base and other energy rate actually charged the members is higher than the stated energy rate because of additional PPFAC adjustors which are charged the CARMs and PRMs per kWh of energy use.

SCHEDULES AND ADJUSTMENTS

Q. Please describe the schedules.

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

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

Q. Please describe Section A of the Schedules.

A. Section A contains summary information. 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 decrease of $4.5 million is 2.92% less than the revenues generated from AEPCO's members under present rates. Current rates produced approximately $15.2 million in electric operating income (margins) in the test year ended December 31, 2011, as adjusted. Based upon an adjusted rate base of $267.5 million, these revenue requirements, as adjusted, generated a rate of return of 5.68%. AEPCO's proposed rates, instead, would produce less than $10.7 million in test year electric operating income, as adjusted. Based upon the test period adjusted rate base, the proposed revenue requirements generate a rate of return of 3.99%. Therefore, AEPCO is requesting a revenue decrease of $4.5 million, which translates to a 2.92% decrease.

Schedule A-2 summarizes the results of operations for the 12 months ending December 31, 2009, 2010 and 2011, as well as the adjusted 2012 test year, with present rates and proposed rates. On an adjusted test year basis, the Test Year Adjusted column shows that AEPCO had a net margin of $6.5 million, a TIER of 1.70 and a DSC of 1.56 in the test year. Assuming the proposed rates, AEPCO would have a test year net margin of about $2.0 million, a TIER of 1.21 and a DSC of 1.32. Schedule A-3 summarizes AEPCO's capital structure and capitalization ratios for the years ended December 31, 2009 and 2010, as well as for the test 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 discuss Section B of the Schedules.

A. Section B contains supporting rate base schedules used in the AEPCO rate filing. Schedule B-1 summarizes the components of the original cost rate base of $267.5 million as of December 31, 2011. It includes gross utility plant in service of $452.7 million, accumulated depreciation and amortization of $220 million and allowances for working capital of $34.8 million. Three adjustments were made to the original cost rate base for the test year (Schedules B-2 and E-5, pages 3-4). AEPCO made adjustments to Utility Plant to reclassify acquisition adjustments, as well as to remove plant held for future use, and also made an adjustment to accumulated depreciation, reflecting the <u>proposed</u> depreciation rates (Schedule C-2, page 10). Schedules B-3 and B-4, concerning reconstructed cost new less depreciation rate base, have not been completed. As a not-for-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 $34.8 million. Its remaining pages show the calculation of the different components. Schedule B-5, page 2, concerning the calculation of cash working capital, however, 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. AEPCO is also not 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 prior rate cases.

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 AEPCO's revenues and expenses during the 2011 calendar test year. As noted on Schedule C-1, page 2, AEPCO had operating margins of $829,000 and non-operating margins of $1 million that, together, produced a net margin of $1.9 million. The second column states reclassification adjustments made to the test period which have a zero effect on the net margins.

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 CARMs and then pays to SWTC. These revenues and charges are a pass-through, at cost, of network services provided by SWTC to the CARMs. Therefore, AEPCO has removed them from its cost of service. The net impact of this and the following 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 prior rate cases.
4. Property Tax Reclassification – This adjustment reclassifies property taxes—which are recorded in various operation and maintenance expense categories according to RUS 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. ED2 Sales Contract Termination – This adjustment annualizes the test year effect of the expiration of the 8 MW sales contract to Electrical District 2 ("ED2") that will occur on September 30, 2012. This agreement became effective on October 1, 1987 for a term of 25 years. AEPCO has removed the contract's revenues, as well as its associated fuel costs, from test year results. In addition, we eliminated the associated charges that were

paid to SWTC to wheel the 8 MW of power associated with this contract. This adjustment decreases net margins by $1.4 million.

2. Coal Cost Adjustment – AEPCO had rail transportation contracts with two railroads that expired on December 31, 2008. When it became evident that new agreements with the railroads could not be reached, AEPCO became a common carrier customer. After analysis of the common carrier tariff rates and terms of service, AEPCO decided that the tariff rates were unjust and filed a complaint with the Surface Transportation Board in 2008, seeking rate relief and the establishment of reasonable rates and other terms of service for its unit coal train transportation service.

The Surface Transportation Board issued its Decision No. 41181 on November 22, 2011. It established new lower rail rates for the period 2009 through 2018 and also awarded AEPCO $9.2 million in reparations for rail transportation costs paid in 2009, 2010 and 2011. Because the amount of reparations has been appealed by the defendants in the Surface Transportation Board complaint proceeding, AEPCO has recorded the $9.2 million received as a deferred credit until such time as the matter is finally resolved. When that happens, AEPCO will discuss with the Commission a mechanism to distribute all or some portion of those reparations to its customers. Therefore, the reparations are not being addressed in this rate application.

But, as a result of the new tariff rates and terms of service, AEPCO has been able to negotiate new coal supplies for 2012 at a much lower cost than was recorded in the test period. Taking these new coal commodity rates and rail transportation rates into account, AEPCO has included a pro forma reduction in test year coal expenses of approximately $11 million and, correspondingly, the effect is to increase margins by that amount.

3. Fixed Gas Charges Adjustment – AEPCO has included a pro forma reduction of $48,000 to fixed gas costs in the test year to reflect the difference between approximately $193,000 in increased fixed gas costs for El Paso Natural Gas transportation charges, but a $241,000 reduction for Chevron storage charges. This increases margins by $48,000.

4. Labor Expense Adjustment – This adjustment annualizes labor expense and associated payroll taxes and benefits to reflect reductions in staffing levels and wage increases that occurred during the test period, as well as known and measurable wage increases that are taking effect in 2012. In 2011, AEPCO and SWTC reduced staff levels from 302 employees to the current level of 261. This adjustment reflects AEPCO's portion of these staffing reductions and results in a $2.3 million increase to net margins.

5. Maintenance Outage Overhaul Adjustment – This adjustment to test period costs amortizes minor outage expenses over a three-year period, rather than a two-year period, and major outage expenses over a six-year period. This increases net margins by $411,000.

6. AEPCO Point-to-Point Wheeling Contracts Adjustment – Prior to 2011, AEPCO had contracts with SWTC in the aggregate amount of 48 MW for point-to-point service. As explained previously in the ED2 Sales Contract Adjustment discussion, 8 MW of this 48 MW point-to-point service will end with the termination of the ED2 contract this September. However, on January 1, 2011, AEPCO entered into an additional 50 MW of point-to-point service to provide the necessary wheeling paths to accommodate an N-1 event on SWTC's transmission system. On January 1, 2012, AEPCO consolidated these

40 MW and 50 MW contracts with an additional 20 MWs of required service to establish a new N-1 contract of 110 MW of point-to-point service. AEPCO has included a pro forma adjustment to reflect this additional $925,000 of increased wheeling costs for the additional 20 MW which was not reflected in the test period amount.

Further, in addition to this N-1 point-to-point contract, AEPCO also intends to enter into a 205 MW point-to-point contract with SWTC to provide the necessary wheeling paths to meet AEPCO's Southwest Reserve Sharing Group ("SRSG") obligations. This service will start at the same time new rates take effect in both the AEPCO and SWTC rate applications. AEPCO has included a pro forma adjustment to reflect the additional $9.5 million of increased wheeling costs for the additional 205 MW not reflected in the test period. However, AEPCO also understands that the $10.4 million in additional revenue to SWTC for these two contracts will result in <u>lower</u> point-to-point transmission service rates emerging from SWTC's application for rate relief. Therefore, AEPCO has estimated that its point-to-point wheeling expense will decrease by $4.2 million based upon estimated point-to-point service rates and Schedule 1 charges of $2.748 per kW month as opposed to the current tariff rates of $3.853 per kW month. Therefore, this adjustment will increase AEPCO's wheeling expenses by $6.2 million ($10.4 million less $4.2 million) and, correspondingly, decrease net margins by the same amount.

7. <u>Scheduling and Trading Services Adjustment</u> – This adjustment annualizes revenues associated with scheduling and trading services agreements between AEPCO and various other parties. The effect of this adjustment increases net margins by $333,000.

8. APM Regional Trading Center Adjustment – In 2011, AEPCO negotiated an agreement with Aces Power Marketing ("APM") to establish a regional trading center. The center became operational on May 1, 2011 and AEPCO transferred its load scheduling and trading services to APM. This agreement allowed AEPCO to achieve costs savings through staffing reductions that have been reflected in other adjustments. This adjustment annualizes the increased fees associated with the load scheduling and trading services now provided by APM. This adjustment decreases net margins by $870,000.

9. AEPCO Cost Cutting Program Adjustment – This adjustment reflects the impact of certain non-payroll-related cost cutting measures instituted by AEPCO during 2011. The effect of this adjustment increases net margins by $764,000.

10. Rate Case Expense Amortization – This adjustment assumes legal costs and expenses associated with the rate application of $240,000 and amortizes those expenses over a three-year period. The effect of this adjustment results in a decrease in net margins of $80,000.

11. California Parties Legal Cost Adjustment – Certain California investor-owned utilities and the California Electricity Oversight Board (the "California Parties") filed lawsuits in federal district court against certain non-jurisdictional entities, including AEPCO, seeking contract-based refunds for the regular and summer refund periods in connection with complaints about the high prevailing prices for wholesale electricity sold in markets operated by the California ISO and California PX during 2000 and 2001. Those lawsuits were dismissed for lack of subject matter jurisdiction, but were re-filed by the California Parties. On March 21, 2012, AEPCO reached an agreement with the California Parties to settle those pending claims in the Los Angeles Superior Court, the 9th Circuit Court of Appeals and the FERC. The settlement covers both the regular and

summer refund periods for the 2000 to 2001 period. AEPCO expects that the settlement will be finalized and approved later this year. Therefore, AEPCO has adjusted test year expenses to remove the legal and consulting fees incurred by AEPCO in relation to the California Parties lawsuits as a non-recurring expense. This adjustment increases net margins by $1.2 million.

12. South Point PPA Capacity Adjustment – This adjustment reflects increases in the South Point Energy Center ("South Point") purchased power contract capacity from 25 MW to 35 MW and the capacity charge from $8.65/kW month to $8.70/kW month as required by the terms of this contract. This adjustment decreases net margins by $530,000.

13. Depreciation and Amortization Adjustment – This adjustment reflects the revised depreciation rates that are proposed by AEPCO and which are discussed in Peter Scott's testimony. The adjustment is predicated on useful life estimates through 2020 for the gas-fired units and 2035 for the coal-fired units. The revised depreciation rates increase depreciation expense by $1.4 million. In addition to the depreciation rates, AEPCO is proposing that the estimated net decommissioning costs be amortized over the remaining 22-year life of Apache Station, which increases amortization expenses by about $2 million per year. Finally, the adjustment removes the accretion expense recorded in 2011 for AEPCO's Asset Retirement Obligations, which was disallowed for rate-making purposes in AEPCO's last rate case, and amounts to approximately $154,000. These adjustments combined decrease net margins by $3.2 million.

14. CUT Debt Refinancing – During 2011, AEPCO prepared an economic analysis of the feasibility of calling its Cooperative Utility Trust ("CUT") Certificate bearing an interest rate of 7.74%. AEPCO subsequently applied to the Commission for permission to

refinance the CUT Certificate with new debt from the National Rural Utilities Cooperative Finance Corporation ("CFC"). In Decision No. 72508, the Commission approved AEPCO's request. In December 2011, AEPCO drew loan funds from CFC that were paid to an escrow account administered by the Trustee in accordance with a 30-day prefunding requirement. On February 1, 2012, the CUT Certificate was then called by the Trustee and the transaction was completed. AEPCO has made an adjustment to the test year expenses to reflect the annual interest savings associated with the refinancing. This increases net margins by $532,000.

15. Interest Expense Adjustment – This adjustment annualizes interest expense based upon debt balances and interest rates at the end of the test year (adjusted for the CUT Certificate refinancing) and decreases interest expense by $704,000. Net margins are increased by the same amount. In addition, AEPCO has adjusted the principal payments for the test period to reflect the principal payments due within the next year. This increases principal payments by $1.2 million.

16. Purchased Power and Fuel Synchronization – This adjustment increases revenues to synchronize the PPFAC revenues with the pro forma fuel and purchased power energy costs made in previous adjustments, which decreases margins by $285,000.

As indicated on page 10 of Schedule C-2, these pro forma adjustments to expenses and revenues resulted in an increase in net margins of $4.6 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, 2009, 2010 and 2011 and the projected 12 months ended December 31, 2012. Schedule D-1 sets forth the computed cost of capital as of December 31, 2011 for the actual and projected year ended December 31, 2012. Invested debt capital amounted to $220.453 million with a composite cost rate of 4.79%. 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 the three actual years and the projected year. Schedules D-3 and D-4 (preferred stock and common equity) are not applicable to AEPCO, because it is a member-owned, not-for-profit cooperative.

Q. Please describe Section E of the Schedules.

A. Section E contains financial statements and statistical schedules for the 12 months ending December 31, 2009, 2010 and 2011. 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 on utility plant additions during the test year and balances as of December 31, 2010 and 2011, along with pro forma adjustments. 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 April 23, 2012. It contains the information referenced in Schedule E-9.

Q. 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 these schedules.

Q. Please describe Section G of the Schedules.

A. Section G of the Schedules contains the cost of service schedules. They were developed according to the rate settlement agreements that were approved in AEPCO's last rate case decision and are consistent with the Commission's rate filing requirements. 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 use a rate base to develop returns, this schedule shows the effective level of return so as to comport with the filing requirements. 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, 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 PRMs MEC, SSVEC and TRICO, as well as the CARMs. Costs which have been functionalized as Base Resources, Other Existing Resources and Additional TRICO Resources and Additional CARM 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 Monthly Fixed Charge and Monthly O&M Charge dollar amounts for MEC, SSVEC, TRICO and the CARMs (lines 36-37). In addition, by identifying and grouping energy costs by resource function, separate energy charges for MEC, SSVEC, TRICO and the CARMs were developed which reflect the specific supply resource costs attributable to each of these Class A Members (lines 38-41).

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, Additional TRICO Resources and Additional CARM Resources. Schedule G-6, page 1 summarizes the account-by-account assignment of expenses to the four resource functions after reclassifications and pro forma adjustments have been made. Schedule G-6, page 2 provides the account-by-account assignment of booked expenses to the four 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 that function. Production fuel expense (Account 547) is the fuel cost of the Other Existing Resources and is functionalized accordingly. 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) is assigned to functions based upon contractual obligations. That is, the energy and demand costs of the WAPA contracts are assigned to Base Resources, because these agreements are firm base load supply contracts. However, the members have agreed that the costs associated with the South Point and PPL Energy Plus (aka Griffith) contracts, as well as pre-pool purchases made on behalf of TRICO or the CARMs, are either TRICO or CARM additional member resources. Thus, on a going-forward basis, the costs of these PPAs and direct assignable purchases should be direct assigned as Additional 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, excluding a directly assigned amount associated with the dispatching of TRICO or CARM additional resources), Other Expenses (Account 557) and Transmission of Electricity by Others (Account 565, excluding a directly assigned amount associated with the Liberty to Marana transmission wheeling path) were functionalized on the basis of the proportions of energy from each of the Base and Other resource types insofar as the scheduling and transmission of this energy is the cost driver for these costs. Administrative and General Expense and General Plant Expense were assigned 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 with 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 information concerning the distribution of AEPCO's pro forma adjustments to test year expenses to the functions of Base Resources, Other Existing Resources, Additional TRICO Resources and Additional CARM Resources. On this page, each of the pro forma adjustments 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 pro forma adjustments described previously in my testimony. The Additional Resources functions of purchased power expense (Account 555) were increased to reflect the South Point adjustment previously discussed. The Base and Other Resources functions of Transmission of Electricity by Others (Account 565) reflects the reduction in point-to-point costs associated with the ED2 adjustment and the increase in point-to-point costs associated with the N-1 and SRSG adjustments discussed previously and are assigned in the same manner as set forth on Schedule G-6, page 2. The Depreciation expense adjustment and adjustments for Interest on Long-Term Debt were assigned to functions based upon the associated costs from Schedule G-6, page 1. 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, Additional TRICO Resources and Additional CARM 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) reflect the removal of SWTC 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. 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. 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-6, page 5 (line 66), AEPCO receives about $8.7 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, Economy Energy Sales from AEPCO generation assets, Scheduling Revenues for scheduling services provided to CARMs and Other Operating Revenues from miscellaneous sources. Economy Energy revenue is entirely variable charge revenue and results from both Base Resources sales, as well as revenue from sales from Other Existing Resources. Scheduling Revenues are functionalized entirely to Base Resources and are classified as fixed 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 of AEPCO's generation resources and not from TRICO or CARM additional resources, these revenues are functionalized and classified on the basis of Base and Other Existing Resources 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.

Q. Please describe Schedule G-8.

A. Schedule G-8 shows the derivation of fuel charge bases that AEPCO is proposing in this rate application. AEPCO is proposing certain modifications to its existing PPFAC which I'll discuss shortly. These fuel charge bases have been conformed to reflect those proposed modifications to AEPCO's PPFAC.

Q. Please describe Section H of the Schedules.

A. Section H of the Schedules summarizes the effect of the proposed rates on the associated revenues and details the revenue increases (decreases) by classes.

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 and Other Existing Resources).

Schedule H-2, pages 5 through 10 contains detailed monthly rate revenue information at actual present and proposed rates for each Class A Member. These pages employ the actual fixed, O&M and energy revenues, as well as the PPFAC adjustor revenue accrual by month, for the test year, and also provide the dollar and percentage impacts of the proposed revenue changes and the per books total revenue. Page 11 is a recap schedule that provides a summary of actual present and proposed revenues for CARMs and PRMs. Page 12 has information on 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 accrual revenue has been synchronized based upon rates and

PPFAC bases that became effective on January 1, 2012 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 and proposed revenues for CARMs and PRMs. 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 10 provide the present monthly charges for MEC, SSVEC, TRICO and the CARMs. Lines 12 through 21 provide the proposed rates for these members. Lines 23 through 32 then set forth the changes in the monthly rates from present to proposed rates.

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. This provides the "typical" customer information specifically applicable to each customer. 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.

THE PPFAC

Q. Does AEPCO have recommendations concerning the PPFAC?

A. Yes. AEPCO requests that the Commission approve continuation of the adjustor mechanism authorized in the last rate case decision, but with two modifications. Based on discussions with our Class A Members, AEPCO proposes to recover fixed fuel costs from a separate PPFAC "pool" which will carry its own fuel adjustor rate based upon a monthly charge. In addition, AEPCO requests that the bank balances be separated from the fuel adjustor rates and, instead, be recovered through a six-month amortization temporary tariff rider.

Q. Why is AEPCO recommending these two changes to the PPFAC?

A. By separating these two cost components—*i.e.*, fixed fuel costs and historic over- or under-collections—from the primary adjustor rate, we will send a clearer, more timely and accurate price signal to our members about the current cost of AEPCO's resources. As the Commission knows, three of our largest members (MEC, SSVEC and TRICO) are PRMs. They are not required to purchase their energy from AEPCO subject to certain contract minimum provisions, but can and do purchase from others. Understandably, they "shop" for the best deal for their retail members. Under the current PPFAC adjustor pricing system, which includes fixed cost and historic over- or under-collection amounts, the price signal which AEPCO sends these members is blurred and makes comparisons difficult as to how AEPCO's current charges compare to the real time market. By making these changes, we will send more accurate and timely purchase information to our members to encourage and facilitate the best use of our resources. That benefits not only the distribution cooperative purchasing the power, but all members as well, because our resources will be used at their maximum, cost-effective potential.

Q. Does AEPCO have other recommendations regarding the PPFAC?

A. Yes. AEPCO requests that the Commission approve continuation of the efficacy provision in relation to the PPFAC that has been approved in prior rate cases.[1] Specifically, the Commission has authorized AEPCO to file a request that it review the efficacy of the PPFAC with the submission of any semi-annual PPFAC report. This provision has been helpful in AEPCO's ability to administer and, if necessary, adjust previous PPFAC clause procedures and we ask that it be continued.

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 will be followed that have been in place for the past several years. The adjustor bases shown on Schedule G-8 are the recommended clause bases. As to closing the current clause, AEPCO requests permission to refund or collect the outstanding Class A Members' bank balances as of the effective date of the new rates approved in this case based upon a 12-month amortization to be accomplished through a temporary tariff rider. 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.

[1] *See* Commission Decision Nos. 68071, Finding 36 and page 16, lines 16-18, and 72055, page 17, lines 15-18.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT
GEP-1

EXHIBIT GEP-1

Report of Independent Auditors
and Financial Statements for

Arizona Electric Power Cooperative, Inc.

December 31, 2011 and 2010

MOSS-ADAMS LLP

Certified Public Accountants | Business Consultants

Acumen. Agility. Answers.

CONTENTS

MOSS-ADAMS LLP
Certified Public Accountants | Business Consultants

REPORT OF INDEPENDENT AUDITORS

To 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, 2011 and 2010 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 consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and the 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, 2011 and 2010 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 April 23, 2012 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 assessing the results of our audit.

Moss Adams LLP

Portland, Oregon
April 23, 2012

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ARIZONA ELECTRIC POWER COOPERATIVE, INC.
BALANCE SHEETS

ASSETS

	December 31, 2011	December 31, 2010
UTILITY PLANT		
Plant in service	$ 455,242,525	$ 441,083,929
Construction work in progress	4,164,264	6,046,206
Total utility plant	459,406,789	447,130,135
Less accumulated depreciation	216,747,033	211,537,129
Utility plant, net	242,659,756	235,593,006
INVESTMENTS		
Restricted held to maturity	11,519,818	9,205,654
Unrestricted	8,629,325	8,352,620
Total investments	20,149,143	17,558,274
CURRENT ASSETS		
Cash and cash equivalents		
General unrestricted	1,969,699	11,839,090
Restricted	24,349,037	907,035
Accounts receivable	15,162,903	16,623,776
Accumulated under-recovered fuel and purchased power costs	886,798	-
Inventories, at average cost		
Coal and natural gas	22,224,114	26,305,516
Materials and supplies	8,791,547	8,360,203
Prepayments and other current assets	1,672,883	1,383,436
Notes receivable	269,446	300,000
Total current assets	75,326,427	65,719,056
DEFERRED DEBITS	11,990,085	10,472,055
TOTAL ASSETS	$ 350,125,411	$ 329,342,391

See accompanying notes.

MEMBERSHIP CAPITAL AND LIABILITIES

	December 31, 2011	December 31, 2010
MEMBERSHIP CAPITAL		
Membership fees	$ 430	$ 430
Patronage capital	94,018,120	84,514,564
Unallocated accumulated margins	1,855,198	9,503,556
Total membership capital	95,873,748	94,018,550
LONG-TERM DEBT		
Federal Financing Bank	148,379,199	136,802,687
Cooperative Utility Trust	-	15,110,140
Solid Waste Disposal Revenue bonds	12,810,345	13,484,574
Cooperative Finance Corporation	16,530,350	22,464,067
Capital lease obligation	1,075,072	2,563,182
Total long-term debt	178,794,966	190,424,650
CURRENT LIABILITIES		
Member advances and other investments	9,310,126	14,526,493
Current maturities of capital lease obligation	1,488,110	1,525,247
Current maturities of long-term debt	47,756,484	7,506,642
Accounts payable	9,733,890	10,868,572
Accrued property and business taxes	1,469,864	1,705,992
Accrued interest	2,666,891	2,586,149
Accumulated over-recovered fuel and purchase power costs	-	2,370,303
Other	306,082	1,046,580
Total current liabilities	72,731,447	42,135,978
ASSET RETIREMENT OBLIGATIONS	2,472,291	2,172,974
DEFERRED CREDITS	252,959	590,239
TOTAL MEMBERSHIP CAPITAL AND LIABILITIES	$ 350,125,411	$ 329,342,391

See accompanying notes.

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

	Years Ended December 31,	
	2011	2010
OPERATING REVENUES		
Sales of electric energy		
Members		
Class A - Firm	$ 154,782,715	$ 120,562,010
Class B	-	34,509,885
Class D	1,046,595	1,169,349
Under-recovery of fuel and purchase power costs	3,567,157	40,754,710
Nonmembers	6,867,065	7,742,869
Other, net	3,404,798	2,638,256
Total operating revenues	169,668,330	207,377,079
OPERATING EXPENSES		
Power generation		
Fuel	77,797,324	82,556,366
Operation	10,129,322	10,720,537
Maintenance	17,240,785	19,100,709
Purchased power and interchange	19,866,267	33,333,669
Administration and general	10,886,484	11,126,741
Depreciation, amortization, and accretion	10,104,945	9,502,433
Transmission	9,501,241	18,554,833
Property and other taxes	2,443,469	2,796,317
Total operating expenses	157,969,837	187,691,605
OPERATING MARGIN	11,698,493	19,685,474
Interest and interest related expenses, net	(11,007,085)	(11,591,755)
Other, net	1,163,790	1,409,837
NET MARGIN	1,855,198	9,503,556
UNALLOCATED ACCUMULATED MARGINS, beginning of year	9,503,556	9,956,925
PATRONAGE CAPITAL ALLOCATION	(9,503,556)	(9,956,925)
UNALLOCATED ACCUMULATED MARGINS, end of year	$ 1,855,198	$ 9,503,556

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net margin	$ 1,855,198	$ 9,503,556
Adjustments to reconcile net margin to net cash from operating activities		
Depreciation and amortization	9,951,210	9,367,223
Amortization of deferred charges	67,918	77,989
Amortization of other deferred credits	(337,280)	(337,280)
Patronage capital allocations	(167,675)	(157,885)
Accretion of asset retirement obligations	153,735	135,210
Changes in assets and liabilities		
Accounts and notes receivable	1,491,427	33,489
Accumulated under-recovered fuel and purchased power costs	(886,798)	4,710,231
Inventories	3,650,058	9,064,419
Prepayments and other current assets	(289,447)	(85,135)
Deferred debits	(1,585,948)	533,694
Accounts payable	(1,134,682)	(5,734,058)
Accrued interest	80,742	1,886,177
Accumulated over-recovered fuel and purchased power costs	(2,370,303)	2,370,303
Accrued property and business taxes and other	(976,626)	205,909
Net cash from operating activities	9,501,529	31,573,842
CASH FLOWS FROM INVESTING ACTIVITIES		
Construction expenditures, net	(16,872,378)	(18,536,384)
Purchases and redemptions of investments, net	(2,423,194)	(1,451,938)
Net cash from investing activities	(19,295,572)	(19,988,322)
CASH FLOWS FROM FINANCING ACTIVITIES		
Member advances and other investments, net	(5,216,367)	(4,298,162)
Proceeds from long-term debt	55,789,411	31,750,360
Line of credit activity, net	-	(10,700,000)
Payments on long-term debt and capital lease obligation	(27,206,390)	(17,830,078)
Net cash from financing activities	23,366,654	(1,077,880)

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2011	Years Ended December 31, 2010
CHANGE IN CASH AND CASH EQUIVALENTS	$ 13,572,611	$ 10,507,640
CASH AND CASH EQUIVALENTS, beginning of year	12,746,125	2,238,485
CASH AND CASH EQUIVALENTS, end of year	$ 26,318,736	$ 12,746,125
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid for interest, net of amount capitalized	$ 10,858,425	$ 9,627,589
Noncash investing activities		
Liabilities incurred for asset retirement obligations	$ 145,582	$ 136,569

See accompanying notes.

Note 1 – Organization

Arizona Electric Power Cooperative, Inc. (the Cooperative or AEPCO) 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 three distribution cooperatives with all requirements contracts and three distribution cooperatives with partial requirements contracts. Currently there are no Class B or C members. There is one Class D member, 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 – Due to the regulation of its rates by the ACC, the Cooperative prepares its financial statements in accordance with Regulated Operations. This accounting 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 $28,000 and $16,000 for 2011 and 2010, respectively.

Depreciation is computed on the straight-line basis over estimated useful lives of depreciable property in accordance with rates prescribed by RUS, averaging 2.20% in 2011 and 2010. Minor replacements and repairs are charged to expense as incurred. When utility plant is retired, sold, or otherwise disposed of, the original cost plus the cost of removal less salvage value is charged to accumulated depreciation and the corresponding gain or loss is amortized over the remaining life of plant.

Note 2 – Summary of Significant Accounting Policies (continued)

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 – Accounting standards require 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 accounting for certain investments in debt and equity securities. This accounting provides that the Cooperative classify investments in securities as either trading securities, held-to-maturity securities or available-for-sale securities. At December 31, 2011 and 2010, 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, 2011.

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, 2011 and 2010.

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

Note 2 – Summary of Significant Accounting Policies (continued)

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. For those minor overhauls effective 2012 and thereafter, the benefit period will be three years. 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. The 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. The adjustor terminated on December 31, 2010.

In its January 6, 2011 rate order, the ACC approved a new purchased power and fuel cost adjustor (the adjustor) for the Cooperative and approved a tariff rider to refund the over-collected balances as of December 31, 2010, for the previous adjustor. Starting on January 1, 2011, the new 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.

Note 2 – Summary of Significant Accounting Policies (continued)

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. Significant estimates include the adjustor, depreciation, asset retirement obligation and overhaul amortization. Actual results could differ from these estimates.

Subsequent events – Accounting standards requires disclosure of the date through which subsequent events have been evaluated, as well as whether the date is the date the financial statements were issued or the date the financial statements were available to be issued. The Cooperative has evaluated subsequent events through April 23, 2012, the date the financial statements were available to be issued.

Note 3 – Investments

Investments at December 31 consist of the following:

	2011		
	Amortized Cost	Unrealized Gain	Fair Value
Restricted – municipal bonds	$ 2,951,797	$ 173,296	$ 3,125,093
Restricted – term certificates	8,568,021	-	8,568,021
Investment in associated organizations	4,153,378	-	4,153,378
Patronage capital	4,475,947	-	4,475,947
Total	$ 20,149,143	$ 173,296	$ 20,322,439

	2010		
	Amortized Cost	Unrealized Loss	Fair Value
Restricted – municipal bonds	$ 2,951,797	$ (11,753)	$ 2,940,044
Restricted – term certificates	6,253,857	-	6,253,857
Investment in associated organizations	3,963,837	-	3,963,837
Patronage capital	4,388,783	-	4,388,783
Total	$ 17,558,274	$ (11,753)	$ 17,546,521

Note 3 – Investments (continued)

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

	2011		2010	
	Cost	Fair Value	Cost	Fair Value
Due from one year to five years	$ 1,886,957	$ 1,886,957	$ 2,889,829	$ 2,889,829
Due from six years to ten years	3,344,036	3,344,036	-	-
Due after ten years	6,288,825	6,462,121	6,315,825	6,304,072

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). The investments include two municipal bonds for approximately $959,000 and $1,940,000, which bear interest at 3.45% and 3.55% per annum, respectively.

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, 2011 and 2010, bear interest at 5.00% 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 $630,000 and $657,000 at December 31, 2011 and 2010, respectively, bears interest at 7.57% 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). ZTCs totaling $1,819,403 purchased in 2010 bear interest at 3.68% per annum and mature in 2012. One ZTC, totaling $15,065 as of December 31, 2011 and 2010, is non-interest bearing and matures in 2013. Other ZTCs totaling $3,344,036 purchased in 2011 bear interest at 3.04% per annum and mature in 2018.

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

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

Note 3 – Investments (continued)

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.

In November 2011, the Cooperative invested $195,000 in the capital of Grand Canyon State Electric Cooperative Association (GCSECA). The Cooperative's investment in GCSECA 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 organization's bylaws and/or at their discretion. Of this balance, $3.7 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:

	2011	2010
Rural economic development revolving loan program (see Note 6)	$ 220,409	$ 179,848
Other deposits on account	24,128,628	727,187
Total restricted cash and cash equivalents	$ 24,349,037	$ 907,035

Note 5 - Accounts Receivable

Accounts receivable at December 31 consist of the following:

	2011	2010
Member energy sales	$ 13,491,300	$ 15,666,624
Nonmember energy sales	872,988	516,007
Other	798,615	441,145
Total accounts receivable	$ 15,162,903	$ 16,623,776

Member energy sales - Member energy sales consist of sales to members under their wholesale power sales contracts (see Note 11 - *Member 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. The Cooperative contributed matching funds in the amount of $80,000. In accordance with grant guidelines, initial loans made to qualifying recipients at a zero interest rate were repaid over a ten-year period. The loan repayments were 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. In November 2010, the Cooperative issued a new loan in the amount of $300,000 at an interest rate of 3.00%. As of December 31, 2011 and 2010, the Cooperative has $220,000 and $180,000, 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:

	2011	2010
Deferred overhaul costs	$ 11,188,576	$ 9,603,100
Unamortized debt costs	159,901	209,675
Preliminary survey and investigation and other deferred debits	520,643	520,171
Redemption premium (see Note 8)	120,965	139,109
Total deferred debits	$ 11,990,085	$ 10,472,055

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 2.68% to 9.08% and from 2.95% to 9.08% for December 31, 2011 and 2010, respectively. Quarterly principal and interest installments on these obligations extend through 2035. The obligations are guaranteed by RUS. The Cooperative may prepay all outstanding notes by paying the principal amount plus either 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. In early 2012, $10,643,000 in additional advances were drawn.

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 7.70%, paid semiannually. The note may be prepaid any time after September 1, 2006 at 103.50% 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. This note was prepaid in full in February 2012 and the entire amount outstanding at December 31, 2011 is classified in current maturities of long-term debt.

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, 2011 and 2010 was 1.00% and 1.24%, respectively. Interest is paid semiannually. These bonds are guaranteed by CFC and are not subject to optional redemption prior to maturity.

Note 8 – Long-Term Debt (continued)

Rural Utilities Service – 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 5.00% 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 $65,000 and $1,528,000 at December 31, 2011 and 2010, 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 fixed rates ranging from 2.95% to 4.60% and variable interest rate that is established monthly and effective on the first day of each month. The variable interest rate in effect at December 31, 2011 and 2010 was 3.20% and 4.95%, respectively. Quarterly principal and interest payments on these obligations extend through 2018 and are 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:

2012	$ 47,756,484
2013	9,288,772
2014	9,695,422
2015	10,215,197
2016	10,575,343
Thereafter	137,945,160
	$ 225,476,378

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, 2011.

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

Note 8 – Long-Term Debt (continued)

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, 2011 and 2010 was $248,254,214 and $214,675,274, respectively.

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

	2011	2010
Total interest costs and related amortization	$ 11,034,749	$ 11,607,569
Interest capitalized	(27,664)	(15,814)
Total interest expense	$ 11,007,085	$ 11,591,755

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 $3,721,518 and $9,747,027 at December 31, 2011 and 2010, respectively. The interest rate on these notes averaged .38% and .43% in 2011 and 2010, respectively. Interest expense on these notes was approximately $2,000 and $49,000 for the years ended December 31, 2011 and 2010, 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 $5,222,140 and $4,300,991 at December 31, 2011 and 2010, respectively. The interest rate on these prepayments averaged .51% and .84% in 2011 and 2010, respectively. Interest expense on these prepayments was approximately $4,000 and $37,000 for the years ended December 31, 2011 and 2010, 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 three 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. One Class A all requirements member became a partial requirements member effective January 1, 2011.

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 three 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. One Class A member cooperative that was an all requirements member for 2010 became a partial requirements member effective January 1, 2011.

Class B and Class C Member power sales contracts – There are no Class B or C member contracts at December 31, 2011.

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 months written notice.

Nonmember power and service sales agreements – The Cooperative holds three nonmember scheduling and trading service agreements that have a six-month termination notice, two scheduling and trading service agreements with 90-day termination notices, a nonmember power sales agreement of 8 MW, which expires on September 30, 2012, and a nonmember scheduling and energy trading agreement with an initial term through September 30, 2016, which continues thereafter until terminated by either party upon a two (2) year written notice.

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 11.7 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 18.3 MW during October through February and 23.6 MW during March through September.

Note 11 - Commitments and Contingencies (continued)

- Power purchase agreement with South Point Energy Center to purchase capacity and energy in Peak Hours, 7 days a week, 16 hours a day with day ahead call option, 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, an LS Power subsidiary, to purchase capacity and energy in Peak Hours of 25 MW, 6 days a week, 16 hours a day, with day ahead call option during the months of May through October for the term of the agreement which begins on May 1, 2008 and expires October 31, 2014.

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 an agreement with SWTC for point-to-point transmission for the Cooperative's nonmember bundled power sales agreements. This agreement provides for reserved transmission capacity of 8 MW. It remains in effect so long as the power sale agreement is in effect (see Note 17).

Wholesale transmission contracts - The Cooperative holds separate agreements by which it takes transmission services from other entities totaling 182 MW, which will remain in effect in accordance with each respective service agreement. Beginning January 1, 2011, the Cooperative increased its transmission service with SWTC from 40 to 90 MW. The Cooperative uses these agreements to take delivery of power from certain of its power purchase agreements and from the wholesale power market. In the opinion of management, the Cooperative will be able to continue to use these contracts to provide service to the Class A members in accordance with their agreements.

Rate filing application - On October 1, 2009, the Cooperative filed an application for rate relief requesting new rates to become effective on January 1, 2011 and the continuance of the Cooperative's fuel and purchased power cost adjustor. On January 6, 2011, the Arizona Corporation Commission issued a decision approving a 0.70% decrease in revenues and authorizing new rate tariffs and a purchased power and fuel adjustment clause which became effective on January 1, 2011.

Note 11 – Commitments and Contingencies (continued)

California power sales – ***California refunds*** – In response to complaints about high prevailing prices for wholesale electricity sold in markets operated by the ISO and the CPX, the FERC instituted a proceeding under section 206 of the Federal Power Act (FPA) to determine whether rates in those markets were just and reasonable. It later determined that prices charged in those markets between October 2, 2000 and June 20, 2001 (regular refund period) exceeded a just and reasonable level. The Cooperative stopped selling into the California markets in early January 2001. On July 25, 2001, the FERC ordered refunds for the regular refund period from all sellers, including government utilities and the Cooperative, the only electric cooperative involved, which are otherwise exempt from its regulatory jurisdiction. Government entities and the Cooperative appealed the FERC's decision to the 9th Circuit Court of Appeals, which 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 and cannot order those entities to make refunds. That decision is now final. In other decisions, the 9th Circuit Court of Appeals ordered FERC to give further consideration whether to order refunds for the period from May 1, 2000 through October 1, 2000 (the summer refund period), based on grounds other than FPA section 206(b). FERC's consideration of that matter is ongoing.

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 seeking contract-based refunds and other relief for the regular and summer refund periods against the non-jurisdictional entities including the Cooperative. These suits were dismissed for lack of subject matter jurisdiction, and refiled in California State court, specifically, the Superior Court for the County of Los Angeles. This case was thereafter dismissed as to the Cooperative, without prejudice. Both AEPCO and the California Parties filed appeals. The Court of Appeal dismissed the Cooperative's appeal and later, in May 2010, granted the California Parties' appeal, reviving the litigation. After AEPCO's appeal to the California Supreme Court was denied, the matter was returned to the Los Angeles Superior Court and later set for trial on April 23, 2012. On March 21, 2012, the parties reached an agreement to settle claims currently pending in the Los Angeles County Superior Court, the 9th Circuit Court of Appeals and FERC. The settlement covers both the regular and summer refund periods. Finalization and approval of the settlement is anticipated to occur later in 2012.

Fuel procurement contracts – ***Coal supply agreements*** – To ensure an adequate fuel supply, the Cooperative enters into various long-term fuel contracts. At December 31, 2011, these contracts consist of:

- A spot purchase agreement consisting of two trainloads of coal to be delivered in January and February 2012.
- A 10-month agreement, effective March 1, 2012. The terms of the agreement require the Cooperative to purchase 393,000 tons during the term of the agreement.
- A 9-month agreement, effective April 1, 2012. The terms of the agreement require the Cooperative to purchase approximately 294,000 tons during the term of the agreement.

Note 11 – Commitments and Contingencies (continued)

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, in 2008 the Cooperative filed a complaint with the Surface Transportation Board (STB) seeking the establishment of reasonable rates and other terms for unit train coal transportation service.

The STB rendered its decision on November 22, 2011 finding in favor of AEPCO, ordering the defendants to pay reparations to the Cooperative for prior shipments and noting that the STB will prescribe the maximum lawful transportation rate that the defendants can charge through 2018. The amount of reparations due to AEPCO has been appealed by the defendants. As such, the Cooperative has not recorded the settlement as of December 31, 2011.

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).

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, 2006. 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 41% 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. Effective March 1, 2010 the agreement was extended for another three years.

Note 11 - Commitments and Contingencies (continued)

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 entered into an agreement with Sierra for the purchase or sale of natural gas at the then prevailing market price for natural gas. The agreement became effective March 17, 2003 and was terminated effective September 30, 2011.

Letters of credit - Letters of credit were obtained by the Cooperative from CFC for the purpose of providing credit support for a power purchase agreement with Griffith Energy LLC and for a five-year lease with Marquette Equipment Financing, respectively. As of December 31, 2011, the remaining balances of these letters of credit were $1,653,750 and $118,648, 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 Marquette 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 June 24, 2014. As of December 31, 2011, 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, 2011 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 written notice. No amounts were drawn under this line of credit for the years ended December 31, 2011 and 2010.

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.

Note 11 – Commitments and Contingencies (continued)

The initial period of the lease is twenty (20) quarters starting April 1, 2009. On June 23, 2009, the Cooperative entered into a master lease agreement to finance the purchase and installation of a telephone system. The period of the lease is sixty (60) months starting October 1, 2009. Future minimum lease payments are as follows:

2012	$ 1,647,655
2013	997,860
2014	134,840
Total minimum lease payments	2,780,355
Less amount representing interest	217,173
Present value of minimum lease payments	2,563,182
Less current portion	1,488,110
	$ 1,075,072

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 2011 and 2010.

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, except to the extent of unrelated business income, if any. The Cooperative follows FASB Accounting Standards Codification (ASC) 740-10, relating to accounting for uncertain tax positions. As of December 31, 2011 and 2010, the Cooperative does not have any uncertain tax positions. The Cooperative files an exempt organization and unrelated business income tax return in the U.S. federal jurisdiction and the states of Arizona, California, North Carolina, New Mexico, and Indiana and is no longer subject to examination by taxing authorities before 2008.

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. In response to impacts from the economic downturn, the required contribution rate increased significantly in 2010 and was adjusted for market conditions in 2011. Contributions made to this plan approximated $331,000 and $466,000 for the years ended December 31, 2011 and 2010, 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 $29,000 and $60,000 for the years ended December 31, 2011 and 2010, respectively.

Note 15 - Operating Leases

Commercial office building - Effective January 19, 2009, the Cooperative entered into a payment and cost allocation agreement with Sierra for the sole use of two offices and use of the conference room at the Tucson Office Facility. The Cooperative is assessed by Sierra through cost allocation methodology 17.50% of office facility expenses as defined in the agreement. Rent expense for the lease of the commercial office building was approximately $19,000 and $24,000 for the years ended December 31, 2011 and 2010, respectively, and is included in administration and general on the accompanying statements of revenues and expenses and unallocated accumulated margins. This agreement was terminated September 30, 2011.

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 $363,000 and $383,000 for the years ended December 31, 2011 and 2010, respectively, and is included in administration and general on the accompanying statements of revenues and expenses and unallocated accumulated margins.

Note 15 – Operating Leases (continued)

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, 2011, these lease agreements consist of:

- A 20-year lease agreement, effective December 17, 2002. Lease payments under this agreement totaled approximately $400,000 in 2011 and 2010. 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 November 23, 2009. This is a full service lease agreement for five railcars to supplement AEPCO's primary train set. Lease payments under this agreement totaled $21,600 in 2011 and 2010.
- A 60-month full service lease agreement for fifteen railcars to supplement AEPCO's primary train set, effective January 20, 2012. Annual lease payments under this agreement will total $96,300.

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, 2011:

2012	$	730,520
2013		627,055
2014		548,586
2015		482,240
2016		473,700
Thereafter		2,272,425
	$	5,134,526

Note 16 – Concentration of Customers and Credit Risk

Revenue and accounts receivable for the year ended December 31, 2011 included amounts from three customers, whom each individually represented more than 10% of the total operating revenue and accounts receivable. Revenue from these customers collectively represented approximately 81% of total operating revenue for 2011. The amounts owed from these customers collectively represented approximately 83% of the total accounts receivable balance at December 31, 2011.

Revenue and accounts receivable for the year ended December 31, 2010 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 84% of total operating revenue for 2010. The amounts owed from these customers collectively represented approximately 87% of the total accounts receivable balance at December 31, 2010.

Note 17 – Related Parties

The Cooperative is a Class B member of SWTC and a member of Sierra. 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, 2011 and 2010, and is carried at cost. The Cooperative's patronage allocation from SWTC was approximately $3,700,000 at December 31, 2011 and 2010.

The Cooperative has entered into an agreement with Sierra, whereby Sierra provides personnel staffing services (see Note 11 - Personnel Staffing Agreement). For 2011 and 2010, the Cooperative recorded expenses for personnel staffing services from Sierra totaling approximately $24,352,000 and $23,816,000, 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 2011, rent received by the Cooperative from SWTC and Sierra totaled approximately $806,000 and $1,397,000, respectively. For 2010, rent received by the Cooperative from SWTC and Sierra totaled approximately $1,135,000 and $1,253,000, 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 2011 and 2010, the Cooperative recorded transmission expenses from these agreements totaling approximately $7,225,000 and $14,082,000, respectively.

As of December 31, 2011, the Cooperative has recorded accounts payable to SWTC and Sierra totaling approximately $664,000 and $489,000, respectively, and there were no accounts receivable from SWTC and Sierra. As of December 31, 2010, the Cooperative had recorded accounts payable to SWTC and Sierra totaling approximately $1,501,000 and $1,000, respectively, and no accounts receivable from SWTC and approximately $1,262,000 from Sierra. The net receivable or payable are included in the accompanying balance sheets as accounts receivable or payable.

Note 18 - Asset Retirement Obligations

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

	2011	2010
Liability at January 1	$ 2,172,974	$ 1,901,195
Accretion expense	153,735	135,210
Liabilities incurred	145,582	136,569
Liability at December 31	$ 2,472,291	$ 2,172,974

REPORT REQUIRED BY GOVERNMENT AUDITING STANDARDS

MOSS-ADAMS LLP
Certified Public Accountants | Business Consultants

INDEPENDENT AUDITOR'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS*

To the Board of Directors
Arizona Electric Power Cooperative, Inc.

We have audited the financial statements of Arizona Electric Power Cooperative, Inc. (the Cooperative) as of and for the year ended December 31, 2011 and have issued our report thereon dated April 23, 2012. We conducted our audit 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.

Internal control over financial reporting – Management of the Cooperative is responsible for establishing and maintaining effective internal control over financial reporting. In planning and performing our audit we considered the Cooperative's internal control over financial reporting as a basis for designing our auditing procedures for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control over financial reporting. Accordingly, we do not express an opinion on the effectiveness of the Cooperative's internal control over financial reporting.

A *deficiency in internal control* exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct misstatements on a timely basis. A *material weakness* is a deficiency, or a combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis.

Our consideration of internal control over financial reporting was for the limited purpose described above and was not designed to identify all deficiencies in internal control over financial reporting that might be deficiencies, significant deficiencies, or material weaknesses. We did not identify any deficiencies in internal control that we consider to be material weaknesses, as defined above.

INDEPENDENT AUDITOR'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS* (continued)

Compliance and other matters – As part of obtaining reasonable assurance about whether the Cooperative's financial statements are free of material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards.*

We noted certain matters that we communicated to the Cooperative's Board of Directors and management in a presentation.

This report is intended solely for the information and use of the Board of Directors and management of the Cooperative, Arizona Corporation Commission and the Rural Utilities Service and supplemental lenders and is not intended to be and should not be used by anyone other than these specified parties.

Moss Adams LLP

Portland, Oregon
April 23, 2012