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April 20, 2005

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Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Re: *Late-filed Exhibits; AEPCO and Southwest Transmission Cooperative Rate Cases; Docket Nos. E-01773A-04-0528 and E-04100A-04-0527*

Dear Sir/Madam:

As discussed at the April 14, 2005 hearing on these matters, attached as late-filed exhibits are the original and 15 copies of (1) the Capital Plan of the Arizona Electric Power Cooperative and (2) the Capital Plan of the Southwest Transmission Cooperative. Both plans were filed with the Commission on December 23, 2002.

Very truly yours,

GALLAGHER & KENNEDY, P.A.

By: Michael M. Grant

Michael M. Grant

MMG/plp
10421-36/15169-6/1266227

Enclosures

Original and 15 copies delivered to
Docket Control this 20 day of April, 2005.

Copy of the foregoing mailed
this 20th day of April, 2005, to:

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ARIZONA ELECTRIC POWER COOPERATIVE
Capital Plan

Introduction

Arizona Electric Power Cooperative, Inc. ("AEPCO") is a non-profit generation cooperative owned by its members. Membership in AEPCO consists of six Class A member distribution cooperatives, one Class B member and one Class C member. The Class A members include Anza Electric Cooperative, Duncan Valley Electric Cooperative, Graham County Electric Cooperative, Mohave Electric Cooperative, Sulphur Springs Valley Electric Cooperative and Trico Electric Cooperative. Mohave Electric Cooperative is provided power pursuant to a partial requirements contract and the other five member distribution cooperatives are provided power on an all-requirements basis. The Class B member is the City of Mesa and the Class C member is the Salt River Project. Mesa and the SRP have firm contracts for fixed terms for specified amounts of power and energy.

AEPCO produces much of the power it sells at its Apache Generating Station which is located southwest of Wilcox. The Apache Generating Station consists of three steam-fired turbine generating units (either coal or natural gas fuel) and four combustion turbines (natural gas or distillate fuel) with a total generating capacity of 555 MW. In addition to its generation resources, AEPCO purchases supplemental power and energy to serve its total load commitments.

In Decision No. 64227 and again in Decision No. 65210, the Arizona Corporation Commission ("Commission") ordered AEPCO to file a capital plan with the Commission by December 31, 2002. In Decision No. 64227, the Staff of the Commission ("Staff") recommended that AEPCO's plan specify a membership capital (i.e. equity) position of 10 percent by

December 2006, 15 percent by the end of 2010 and 30 percent by the end of 2015. The purpose of this Capital Plan is to comply with Commission Decision Nos. 64227 and 65210.

Summary

As will be explained in greater detail below, AEPCO has made tremendous and steady progress in improving its financial position over the past ten years. Following a series of economic events in the 1980's which placed AEPCO in a negative equity position of more than $51 million by 1990, in sharp contrast AEPCO's 2001 equity position was a positive $14 million or 5.4% as a percentage of assets.

AEPCO's most recent Board approved financial forecast expects this trend of financial improvement to continue. Based on several assumptions, projected equity levels reach 12% in 2006, 27% in 2010 and 31% in 2011. Each of these projections exceed the Staff recommendations reflected in Decision No. 64227.

Background

In addition to the Commission, the Rural Utilities Services (RUS) also regulates AEPCO. RUS's jurisdiction is based on a variety of sources including its guarantee of certain debt that AEPCO, as a power supply borrower, incurs from the Federal Financing Bank (FFB). The RUS requires that power supply borrowers generate sufficient margins to maintain a Times Interest Earned Ratio ("TIER") of 1.05 and a Debt Service Coverage Ratio ("DSC") of 1.0. AEPCO is also required to maintain these ratios as a part of its mortgage covenants with the RUS. Prospective requirements for TIER and DSC require power supply borrowers like AEPCO to design and implement rates for electric power, energy and other services to provide sufficient revenue to (1) pay all fixed and variable expenses, (2) provide and maintain reasonable working capital and (3) maintain, on an annual basis, the TIER and DSC margin requirements. In addition, the retrospective requirement of the RUS covenants mandates that the average TIER and DSC levels achieved in the two best out of the three most recent calendar years must meet the levels of 1.05 and 1.0, respectively. For most of its recent history, AEPCO has been able to achieve and maintain these required TIER and DSC levels.

Those interested in the financial performance of the Cooperative, including its members and their representatives which serve on AEPCO's Board of Directors, financial institutions and management, view the level of an organization's equity as only one indicator of its financial strength. Generally, however, businesses with high equity levels are viewed as less debt leveraged and, therefore, financially stronger than systems with lower equity levels. RUS mortgage covenants require that borrowers like AEPCO must achieve an equity level of 40 percent in order to return patronage capital credits in an amount greater than 25 percent of the prior year's margins without the specific written approval of the RUS. But, except for the financial ratio and patronage capital retirement restrictions, RUS has no equity management requirements for its power supply borrowers.

Exhibit 1 shows AEPCO's annual equity positions since 1990. The most significant prior changes in AEPCO's equity profile occurred with the economic recession in the 1980's which resulted in a decline in irrigation loads and a collapse in the copper market. The decline in the copper market was the most devastating for AEPCO and its members. It ultimately resulted in the loss of a 100MW Anamax mining load and the reduction in a supply contract from 100MW to 75MW with the Phelps Dodge Corporation.

Despite two rate increases (Decision Nos. 53034 and 53932) and three reduction in workforce layoffs in the early and mid 1980's, AEPCO continued to experience annual losses throughout the 1980's. Ultimately, AEPCO was forced to put one of its 175 MW steam units in "stand-by" status and deferred recording its associated fixed costs during 1988 and 1989. All these events produced a series of annual net margin deficits leaving the Cooperative in a negative equity position which exceeded $51 million in 1990.

By the early 1990's, however, economic conditions had improved generally and AEPCO's load profile had begun to recover. AEPCO also put in place several additional programs designed to address the deficit equity position and improve its long-range financial picture while simultaneously providing its Class A Members with lower, stable rates. Initiatives included a debt-restructuring process that repriced, refinanced or restructured nearly 85 percent, or about $296 million, of AEPCO's outstanding debt. As a result of this debt restructuring program, AEPCO lowered its composite debt cost by 250 basis points which ultimately will achieve nearly $65 million in total debt service savings. This program also resulted in an annual reduction in interest expense of approximately $5 million. AEPCO also changed its coal supplier resulting in coal priced $0.30/MMBtu lower than the previous supplier. The reduced fuel expenses allowed AEPCO to refund more than $15 million to its members. AEPCO also instituted other cost containment programs including (1) an early retirement offer in 1995, (2) working successfully to change the property tax valuation methodology at the state legislature and (3) focusing on an administrative and general expense cost containment program.

The effect of these cost reduction and cost containment programs together with increasing member load levels and sales in the economy energy markets allowed AEPCO to raise its equity level from the more than $50 million deficit in 1990 to a positive level of $14 million in 2001.

Equity as a percentage of assets increased from a negative 14.9 percent to a positive 5.4 percent in 2001. Notably, AEPCO was able to accomplish this while also reducing member rates by some 22% in the 1986-2001 time frame.

Capital Plan

AEPCO's most recent Board approved financial forecast is dated October 9, 2001. Equity levels contained in this forecast reach 12 percent in 2006, 27 percent in 2010 and 31 percent the following year. All exceed the Staff recommendations stated in Decision No. 64227. Attached as Exhibit 2 is an annual computation of projected equity ratios for the forecast period. Exhibit 3 sets forth major assumptions used in the forecast. There are a number of operating and non-operating assumptions underlying the forecasted equity results in addition to an assumption that AEPCO will add over $103 million of new plant by the end of the forecast period in 2011. This capital expansion profile includes the $30 million investment in the 38MW gas turbine at Apache Power Station which commenced service in October 2002.

AEPCO's most recent planning activities revolve around defining a resource expansion plan that will meet the increasing member distribution cooperative demand and energy forecasts. Currently, AEPCO projects it will need additional capacity beginning in 2003, but plans to satisfy this need through purchased power contracts. AEPCO, however is currently working on the assumption that additional generation will be needed in the year 2007. These plans are being formulated and will not likely be finalized until March 2003. As part of this evaluation and finalization process, a new financial forecast will be formulated and ultimately approved by the Board of Directors. Whether the equity levels specified in the October 2001 Financial Forecast can be achieved while adding additional resources and maintaining member rate stability remains uncertain at this time.

In conclusion, a 2002 survey performed by R.W. Beck to identify current trends in cooperative financial policies included an equity management profile. According to the R.W. Beck report, of the 31 generation and transmission cooperatives surveyed, 23 percent indicated that they have a specific goal for a future equity level to be achieved by the cooperative. The median equity ratio goal for the seven cooperatives which provided one was 17.5 percent and goals specified ranged from 1 to 25 percent. These survey results confirm the point mentioned previously – that the financial strength of a cooperative is evaluated in light of several factors including the strength of member service territories, load projections and economic forces and not just on a predetermined level of equity. AEPCO's future equity levels will be judged and determined in light of these and other factors. AEPCO will attempt to balance the needs of its members for the lowest possible rates while continuing to maintain AEPCO's ability to attract sufficient funds for capital improvement and expansion.

10421-0030/1067868v1

Exhibit 1

Arizona Electric Power Cooperative, Inc.

Computation of Equity Ratios

Calendar Years 1990-2001

Source: REA Form 12

Calendar Year	Total Margins And Equity	Total Assets	Equity Percent of Assets
1990	($51,189,097)	$343,744,228	-14.89%
1991	($50,517,810)	$352,114,332	-14.35%
1992	($50,397,072)	$341,842,098	-14.74%
1993	($48,180,350)	$352,251,358	-13.68%
1994	($40,700,951)	$393,571,955	-10.34%
1995	($44,057,857)	$381,880,668	-11.54%
1996	($35,652,410)	$372,268,481	-9.58%
1997	($22,800,403)	$362,889,094	-6.28%
1998	($8,876,458)	$374,334,962	-2.37%
1999	($4,099,373)	$364,758,787	-1.12%
2000	$7,971,346	$377,492,394	2.11%
2001	$13,904,998	$257,553,539	5.40%

Exhibit 2

Arizona Electric Power Cooperative, Inc.

Computation of Projected Equity Ratios

Calendar Years 2002-2011

Source: 2001 Financial Forecast, October 9, 2001

($000's)

Calendar Year	Projected Total Margins And Equity	Projected Total Assets	Projected Equity Percent of Assets
2002	$8,984	$284,456	3.16%
2003	$13,035	$280,760	4.64%
2004	$18,734	$274,139	6.83%
2005	$25,649	$265,695	9.65%
2006	$33,568	$273,842	12.26%
2007	$42,725	$282,204	15.14%
2008	$51,223	$274,984	18.63%
2009	$61,172	$267,942	22.83%
2010	$70,617	$259,889	27.17%
2011	$77,823	$248,733	31.29%

Exhibit 3
Major Assumptions
October 2001 Financial Forecast

1. Demand and Energy Billing Units incorporated from the 2001 Power Requirements Study (PRS).

2. Demand and Energy Billings Units, once adjusted for maturing contract sales, increase on average at slightly less than 2 percent per year.

3. Average Coal Price of $151.90MMBtu in 2003 escalates at an average annual rate of approximately 2 percent through the forecast period (2011).

4. Average Price of Natural Gas in 2003 of $4.93MMBtu declines at an average annual rate of 3.4 percent through the forecast period (2011).

5. Assumed a Specified Major and Minor Overhaul Profile Schedule throughout the forecast period.

6. Excluding the additional Capacity of GT4 an average annual capital expansion profile of $4.6 million was assumed through 2001.

7. All Additional Generation needs beyond GT4 were satisfied by short term power purchases at an assumed rate schedule which escalated at an average annual rate of 6 percent.

8. Timely and adequate rate adjustments to maintain a Times Interest Earned Ratio (TIER) of at least 1.05 and/or a resulting Debt Service Coverage Ratio of 1.0.

Southwest Transmission Cooperative, Inc.
Capital Plan

Introduction

Southwest Transmission Cooperative, Inc. is a non-profit transmission cooperative owned by its members. There are six Class A distribution cooperative members and three Class B members. The Class A members include Anza Electric Cooperative, Duncan Valley Electric Cooperative, Graham County Electric Cooperative, Mohave Electric Cooperative, Sulphur Springs Valley Electric Cooperative and Trico Electric Cooperative. The Class B members are the Arizona Electric Power Cooperative ("AEPCO"), Sierra Southwest Cooperative Services, Inc. ("Sierra") and Morenci Water and Electric Company.

Southwest was formed in 1999 in anticipation of the restructuring of AEPCO into three separate cooperative corporations: AEPCO, Southwest and Sierra. Under the restructuring and as authorized in Decision No. 63868, as of August 1, 2001, Southwest purchased the transmission business of AEPCO, including the transmission facilities and assets and rights to transmission capability under various agreements.[1] Southwest owns and operates a power delivery system that schedules power into the areas served by its Member cooperatives in Arizona, New Mexico and southern California. It may also provide transmission service to patrons and other users who may not become Members, but who privately contract with Southwest for wholesale transmission service.

In Decision No. 64991, the Arizona Corporation Commission ("Commission") ordered Southwest to file a capital plan with the Commission by December 31, 2002 (page 4, second

[1] Southwest has pending in Docket No. E-04100A-02-0321 an application for a determination that it is not a public service corporation pursuant to Art. 15, Section 2 of the Arizona Constitution. This Capital Plan is submitted without waiver of the issues raised and relief requested in that Application.

ordering paragraph). The Staff of the Commission recommended that Southwest's plan specify a membership capital (i.e. equity) position of 10 percent by December 2006, 15 percent by the end of 2010 and 30 percent by the end of 2015 (Decision No. 64991, Finding 9). The purpose of this Capital Plan is to comply with that requirement of Decision No. 64991.

Summary

As part of the AEPCO restructuring, Southwest assumed a percentage of AEPCO's then outstanding Rural Utilities Service ("RUS"), Federal Financing Bank and other long term debt in order to pay for the transmission business it received as part of the restructuring. It also was allocated a portion of total membership capital. As of December 31, 2001, Southwest's balance sheet reflected a total of approximately $97.9 million in membership capital and liabilities including long term debt of just under $87.5 million and membership capital of slightly more than $1.8 million.

Southwest's most recent Board approved financial forecast expects its equity position to increase over the ten year forecast period from 2001 to 2011. Based on several assumptions, projected equity levels reach 13% in 2006, 26% in 2010 and approach the 30% level in 2011. Each of these projections exceed or are consistent with the Staff recommendations reflected in Decision No. 64991.

Background

Because it is an RUS borrower, Southwest is subject to regulation by that agency, which is a division of the United States Department of Agriculture. As to financial performance standards, the RUS requires that cooperatives like Southwest generate sufficient margins to maintain a Times Interest Earned Ratio ("TIER") of 1.05 and a Debt Service Coverage Ratio ("DSC") of 1.0. Prospective TIER and DSC standards require Southwest to design and implement rates to provide sufficient revenue to (1) pay all fixed and variable expenses, (2) provide and maintain reasonable working capital and (3) maintain, on an annual basis, the TIER and DSC margin requirements. In addition, the retrospective requirement of the RUS mortgage covenants mandates that the average TIER and DSC levels achieved in the two best out of the three most recent calendar years must meet the levels of 1.05 and 1.0, respectively.

Those interested in Southwest's financial performance including its members and their representatives which serve on Southwest's Board of Directors, financial institutions and management, view the level of an organization's equity as only one indicator of its financial strength. Generally, however, businesses with high equity levels are viewed as less debt leveraged and, therefore, financially stronger than systems with lower equity levels. Mortgage covenants require that RUS borrowers like Southwest must achieve an equity level of 40 percent in order to return patronage capital credits in an amount greater than 25 percent of the prior year's margins without the specific written approval of the RUS. But, except for the financial ratio and patronage capital retirement restrictions, RUS has no equity management requirements for its borrowers like Southwest.

In its first five months of operations (August to December, 2001), Southwest did not meet RUS' annual TIER and DSC margin requirements. As a result, Southwest developed new transmission service rates. On July 1, 2002, filed its revised Open Access Transmission Tariff ("OATT") rates with the Federal Energy Regulatory Commission and the Commission. In Decision No. 65367, the Commission approved the revised OATT rates. These revised OATT rates will allow Southwest to meet and exceed the RUS minimum mortgage compliance criteria. In addition, the projected 2002-2003 results will also satisfy the RUS' retrospective requirement discussed previously.

Capital Plan

Southwest's most recent Board approved financial forecast is dated August 14, 2001. Equity levels contained in this forecast reach 13% in 2006, 26% in 2010 and approach the 30% level in 2011. All exceed or are consistent with the Staff recommendations stated in Decision No. 64991. Attached as Exhibit 1 is a page summarizing the annual expected results in the forecast period. The attached Exhibit 2 summarizes certain key assumptions which underlie this financial forecast.

While the major transmission expansion project known as the Winchester Project is included in the August 2001 financial forecast, the potential need to further expand both the backbone transmission system and the delivery capabilities of certain distribution cooperative members of Southwest is under current study and evaluation. These expansion plans, while still in the formulation stage, will include expansion needs that may be identified by the Central Arizona Transmission Study (CATS) sponsored by the Commission. The expansion studies and plans will not likely be finalized until the end of the calendar year 2003, or beyond. As a part of the expansion evaluation process, a new financial forecast will be forthcoming and ultimately approved by the Board of Directors. Whether the equity levels specified in the August 2001 financial forecast can be achieved will obviously depend, to a large extent, on the scope and the scheduled timing of these expansion needs and their associated rate impact.

In conclusion, a 2002 survey performed by R.W. Beck to identify current trends in cooperative financial policies included an equity management profile. According to the R.W. Beck report, of the 31 generation and transmission cooperatives surveyed, 23 percent indicated that they have a specific goal for a future equity level to be achieved by the cooperative. The median equity ratio goal for the seven cooperatives which provided one was 17.5 percent and goals specified ranged from 1 to 25 percent. These survey results confirm the point mentioned previously--that the financial strength of a cooperative is evaluated in light of several factors including the strength of member service territories, load projections and economic forces and not just on a predetermined level of equity. Southwest's future equity levels will be judged and determined in light of these and other factors. Southwest will attempt to balance the needs of its members for the lowest possible rates while continuing to maintain Southwest's ability to attract sufficient funds for capital improvement and expansion.

16169-0003/1068300v1

Exhibit 1

Southwest Transmission Cooperative, Inc.

Computation of Projected Equity Ratios

Calendar Years 2002-2011

Source: 2001 Financial Forecast, August 14, 2001

($000's)

Calendar Year	Projected Total Margins And Equity	Projected Total Assets	Projected Equity Percent of Assets
2002	$4,510	$103,684	4.35%
2003	$6,496	$109,405	5.94%
2004	$8,682	$114,896	7.56%
2005	$11,408	$113,335	10.07%
2006	$14,532	$112,320	12.94%
2007	$18,114	$110,034	16.46%
2008	$21,091	$106,775	19.75%
2009	$24,367	$103,409	23.56%
2010	$27,138	$102,487	26.48%
2011	$28,489	$99,133	28.74%

Exhibit 2

Major Assumptions
August 2001 Financial Forecast

1. Demand and Energy Billing Units pursuant to the 2001 Power Requirements Study (PRS)

2. Operations and Maintenance and Administrative and General Expenses were escalated at an average annual rate of 1.5 percent.

3. Depreciation Rates were assumed at the RUS stipulated rate for transmission facilities of 2.25 percent per year.

4. Ad Valorem Taxes were calculated at an average annual rate of 2.7 percent.

5. Construction Expenditures averaged an annual amount of $4.1 million over the forecast period.

6. Applied the FERC rating making methodology and resulting formulas to calculate and determine Point-to-Point and Network Transmission Service rates.

7. It was assumed that Transmission rates would generate an average annual Debt Service Coverage Ratio (DSC) of 1.0.

8. The rate changes to achieve the required revenue requirement was assumed to be implemented in a timely manner in an effort to achieve the annual DSC objective.