



1 Regulatory Assets and Transition Revenues pursuant to A.A.C. R14-2-1607(D) and Arizona  
2 Corporation Commission ("Commission") Decision No. 60977 (June 22, 1998). AEPCO's filing  
3 sought approval of a Regulatory Asset Charge ("RAC") and a Competition Transition Charge  
4 ("CTC") based on the "transition revenue" or "financial integrity" method authorized by Decision  
5 No. 60977. Pursuant to Procedural Order dated April 21, 1999, as amended, AEPCO, Arizonans  
6 for Electric Choice and Competition ("AECC"), Mohave Electric Cooperative, Inc. ("Mohave") and  
7 Commission Utilities Division Staff ("Staff") filed testimony. On February 18, 2000, North Star  
8 Steel, Inc. ("North Star"), a special contract customer of AEPCO, and Mohave, were granted  
9 intervention. A hearing was held on February 28 and 29, 2000.

10 On May 22, 2000, AEPCO filed Settlement Agreements with two of its special contract  
11 customers which resolve all issues between the affected parties concerning the collection of  
12 stranded costs from these contract customers. In light of the Settlement Agreements, AECC  
13 dropped its opposition to AEPCO's stranded cost recovery plan.

#### 14 Regulatory Asset Charge

15 Regulatory assets are costs which would have been charged as expenses in a previous period  
16 absent an implicit promise by the Commission that they be deferred as an asset and collected from  
17 rate payers in the future. AEPCO's regulatory assets arise from debt refinancing costs and the costs  
18 associated with the buy-out of its Carbon Coal all-requirements contract. They reflect costs that  
19 were incurred in prior periods to reduce AEPCO's cost of service which had been deferred to match  
20 related revenues and expenses. In Decision No. 60977, the Commission recognized that because of  
21 the difficulty of mitigating regulatory assets, as well as the possible financial implications, their  
22 recovery should be assured.

23 AEPCO's regulatory assets totaled \$21,849,000 as of December 1999. As its final position,  
24 AEPCO requested that its regulatory assets be amortized over approximately 11 years, and that the  
25 Commission approve an initial RAC of 1.55 mills per kWh, that gradually reduces to .21 mills per  
26 kWh in the year 2012 or until the full amount of AEPCO's regulatory assets have been recovered,  
27 whichever occurs first. AEPCO adopted Staffs recommended amortization period. The  
28 calculation of AEPCO's RAC is attached as Exhibit A.

1 The costs associated with AEPCO's regulatory assets are already included in current rates.  
2 Current rates would be adjusted to reflect the RAC to insure no double recovery. AEPCO's Class  
3 A members would assess the RAC on all retail sales.

4 To assure that there is no over-recovery of its regulatory assets, AEPCO requested that the  
5 Commission authorize it to make appropriate adjustments to the Distribution Cooperative bills so as  
6 to reduce the bill by the amount of the RAC in effect for any billing period during the amortization  
7 term. In addition, AEPCO anticipates transferring its transmission assets to a newly formed  
8 cooperative known as Southwestern Transmission Electric Power Cooperative, Inc. ("Southwest  
9 Transmission"). Consequently, AEPCO has requested that the Commission authorize AEPCO to  
10 assign the RAC to Southwest Transmission, if necessary to avoid accounting write-offs.

11 AEPCO's RAC is consistent with Decision No. 60977, permitting the full recovery of  
12 Regulatory Assets over a reasonable period. We adopt AEPCO's RAC as reflected in Exhibit A.

### 13 Competition Transition Charge

#### 14 Methodology

15 AEPCO's request for a CTC attempts to maintain AEPCO's financial integrity during the  
16 transition to competition based upon the Debt Service Coverage ("DSC") levels required by the  
17 Rural Utility Service ("RUS"). AEPCO's revenue needs are based on (1) its need to meet current  
18 operating costs; (2) the financial criteria contained in existing mortgages; and, (3) its need to attract  
19 future debt capital from the Federal Financing Bank and National Rural Utilities Cooperative  
20 Finance Corporation and other sources.

21 AEPCO's transitional revenue is the difference between its total generation revenue  
22 requirement for Class A Members (i.e. the revenue requirement necessary to meet generation  
23 related cost) less total generation market price revenues. Total generation price revenues are  
24 determined using a forecast of market price. AEPCO has agreed to Staffs recommended market  
25 price estimate of \$.030 per kWh in the first year commencing July 1, 2000. The transition revenues  
26 are then divided by the Distribution Cooperatives' Arizona load to arrive at a charge per kWh.  
27 Based on Staffs recommendations, AEPCO requested an initial CTC of \$.0091 per kWh. The  
28 calculation of the CTC for the first year is attached hereto as Exhibit B. AEPCO and Staff agreed

1 that the CTC should be collected over five years, or until July 1, 2005. AEPCO would assess the  
2 CTC on the Distribution Cooperatives, who would add it to their unbundled tariffs and collect it  
3 from their retail customers who elected to take power from another supplier. The Distribution  
4 Cooperatives, who comprise a majority of the members of AEPCO's Board of Directors, agreed  
5 with the methodology of calculating the CTC.

6 Pursuant to AEPCO's proposal, as agreed to by Staff, the CTC would not be "trued-up" for  
7 either over or under collection, but would be reset on July 1, 2001 and on July 1 of each subsequent  
8 year based upon the next year's budget figures and an estimate of future market prices. AEPCO  
9 proposed to file with Staff its proposed recalculation of the CTC by May 1 of each year to afford  
10 time for Staff to ask questions concerning the proposal so the Commission could reset the CTC as  
11 of July 1. Pursuant to AEPCO's proposal, if in any year, the calculations produced a zero or  
12 negative number, there would be no CTC in effect for that year.

13 Staff concurred that there did not need to be a negative CTC as long as customers could  
14 return to Standard Offer Service on reasonable terms. In Staff's opinion the time frame to return a  
15 large customer to the system should not be longer than three months unless good cause is shown, and  
16 further, the price for the returning customer should be no higher than the cost of acquiring  
17 incremental power, including transaction costs plus a reasonable margin. AEPCO noted that for the  
18 limited number of large non-standard offer customers on the AEPCO distribution cooperative  
19 system, a notice period of three to six months would be necessary to arrange the details of and  
20 accommodate their return. AEPCO claimed the precise notice and negotiation process is difficult to  
21 specify because they hinge on such factors as (1) whether AEPCO has the power needed  
22 immediately available from its own resources, (2) if not, how long it will take to arrange cost and  
23 other details for power from another supplier and (3) the precise load pattern and amount of  
24 electricity needs of the customer. AEPCO proposed that AEPCO should be required to negotiate  
25 promptly with any large special contract customer for its return to the system and advise the  
26 Commission if and why the return cannot be effectuated within 90 to 180 days of receipt of written  
27 notice.

28 We believe that during the period the CTC is in effect, it is reasonable to require AEPCO to

1 notify the Commission within 60 days of a written request to return to the system from a large non-  
2 standard offer customer if that customer cannot be returned to the system within 90 days of its  
3 request. Such reports will enable the Commission to monitor how quickly large customers are  
4 being returned to the system and allow Staff to become involved early in the process in the event  
5 there is disagreement on the reasonableness of AEPCO's actions.

6 We agree with the methodology for calculating the CTC as agreed to by AEPCO and Staff.  
7 By May 1 of every year through 2004, AEPCO shall file budget and market information sufficient  
8 to recalculate and justify a CTC for the following year.

#### 9 Applicability of CTC to North Star

10 North Star, a contract customer of Mohave and AEPCO, urged the Commission to rule that  
11 neither AEPCO's CTC or RAC should be assessed upon Mohave based on any North Star load that  
12 becomes competitive. North Star has a special three-party contract with Mohave and AEPCO for  
13 Mohave to provide North Star with non-firm power. According to North Star, neither AEPCO nor  
14 Mohave were required to build or contract for long term generation to serve North Star. North  
15 Star's load is fully interruptible and served by market generation sources which North Star has the  
16 ultimate discretion to select. Under the contract, Mohave and AEPCO purchase the energy from  
17 the sources North Star selects and transmits and delivers the energy to North Star. For their  
18 services, AEPCO and Mohave recover actual costs incurred and receive a combined 15 percent  
19 margin markup.

20 AEPCO did not agree that no CTC should be charged to North Star. AEPCO argued that  
21 because its CTC is assessed on the Distribution Cooperatives, the determination of whether North  
22 Star should be charged a CTC should be deferred until Mohave's stranded cost proceeding. AEPCO  
23 also argued that because of North Star's late intervention this issue was not adequately addressed in  
24 this proceeding and failure to charge North Star a CTC and RAC will improperly and unfairly shift  
25 costs to other customers/owners on the AEPCO system.

26 Mohave expressed concerns about the burden that may be placed on the Distribution  
27 Cooperatives to pay AEPCO's authorized CTC in the event certain large-party contract customers  
28 dispute the applicability of the CTC after these customers choose competition. Mohave requested

1 clarification in this Order whether the CTC applies to three-party contract customers, and that if it  
2 did, Mohave wanted clarifying language that the Distribution Cooperatives will not be responsible  
3 for paying an additional share of AEPCO's CTC in the event these contract customers dispute the  
4 applicability of the CTC.

5 In its closing brief Staff argued that AEPCO's CTC should not apply to North Star because  
6 AEPCO has never made power supply commitments to serve North Star and thus had no expectation  
7 of continuing generation revenues from this customer. Staff argued that imposing a stranded cost  
8 charge on an interruptible customer conflicts with the basic concept of stranded cost. Staff  
9 recommended that the CTC should be assessed only against firm load that purchases competitively.

10 The issue of the applicability of the CTC and RAC to North Star should be deferred to  
11 Mohave's stranded cost proceeding. If our decision in that matter adjusts the CTC authorized  
12 herein, Mohave will only be required to collect from and remit to AEPCO the charges we authorize  
13 at that time in relation to North Star.

#### 14 Applicability of CTC to Other Contract Customers

15 Subsequent to the hearing, on May 22, 2000, AEPCO filed two Settlement Agreements  
16 among (1) Phelps Dodge Corporation ("Phelps Dodge"), AEPCO and Trico and (2) Chemical Lime  
17 Company of Arizona ("Chemical Lime") and AEPCO. Copies of the Settlement Agreements are  
18 attached hereto as Exhibit C, and incorporated herein by reference. Phelps Dodge and Chemical  
19 Lime are members of AECC, and intervenor AECC has accepted and agreed to both Settlement  
20 Agreements and has agreed to accept AEPCO's methodology for determining its RAC and CTC.

21 Phelps Dodge is a party to two special contracts with AEPCO and Trico. In their settlement,  
22 the parties agreed that the CTC related to these contracts shall be 75 percent of the CTC approved by  
23 the Commission. The parties also agreed that AEPCO's RAC as approved by the Commission shall  
24 apply to all power purchased by Phelps Dodge from a supplier other than AEPCO so long as the  
25 RAC is in effect. The parties agreed to increase the rates under the special contracts and submit the  
26 amendments to the Commission for approval.

27 Chemical Lime and AEPCO are parties to a Peak Load Shedding Agreement. Chemical  
28 Lime and AEPCO have agreed that in the event Chemical Lime opts to take power from another

1 supplier, the CTC related to the Chemical Lime load shall be 70 percent of the CTC approved by the  
2 Commission, and that the RAC as approved by the Commission shall apply to all kWhs Chemical  
3 Lime takes from a power supplier other than AEPCO.

4 The parties to the Settlement Agreements submitted them subsequent to the hearing and there  
5 has been no testimony on their terms. Our concern is that contract customers pay their fair share of  
6 AEPCO's stranded costs so that the smaller non-contract customers do not have to make up the  
7 difference. Consequently, each year when AEPCO seeks to reset its CTC, we will require that the  
8 calculations occur in the same sequence, first the Exhibit B calculation, then the calculation of the  
9 Phelps Dodge and Chemical Lime CTCs.

#### 10 Effect of Restructuring

11 Mohave expressed concerns about the effect of AEPCO's restructuring on the  
12 implementation of a CTC. Under AEPCO's contemplated restructuring plan, AEPCO's Class A  
13 members will have the option of maintaining their current all-requirements wholesale power contract  
14 or enter into a new Partial-Requirements Capacity and Energy Agreement ("PRA"). Under the PRA,  
15 the partial-requirements member receives an agreed upon percentage allocation of AEPCO's current  
16 capacity, and the partial-requirements member will be responsible to acquire future capacity and  
17 energy above the PRA allocation to meet its load requirements. Mohave envisioned a scenario  
18 where a Standard Offer customer of a partial-requirements member elects to become a Direct Access  
19 customer at a point in time when the partial-requirements member is acquiring supplemental power  
20 resources from sources other than AEPCO. The loss of energy sales due to the customer electing  
21 Direct Access will impact the resources provided by the partial-requirements member as well as  
22 AEPCO. Mohave believed that AEPCO would be entitled to collect its CTC for the sales that it  
23 loses due to the customer electing Direct Access, but that AEPCO should not be entitled to apply its  
24 CTC to that portion of the energy sales that the partial-requirements member had provided from  
25 other sources.

26 Mohave recognized that AEPCO's restructuring is not complete and that it is currently  
27 impossible to determine whether the implementation of the CTC plan contemplated herein will be a  
38 contested issue for a potential partial-requirements member. Mohave requested that the Commission

1 include language in this Order that recognizes that AEPCO is currently engaged in restructuring and  
 2 that this could require the re-examination of AEPCO's stranded cost methodology as it applies to  
 3 partial-requirement members in a future proceeding. AEPCO agreed with Mohave that the issue  
 4 could be deferred until the Commission considers approval of the contemplated restructuring.

5 \* \* \* \* \*

6 Having considered the entire record herein and being fully advised in the premises, the  
 7 Commission finds, concludes, and orders that:

8 **FINDINGS OF FACT**

9 1. On August 21, 1998, AEPCO submitted its Application for Approval of its Filing as to  
 10 Regulatory Assets and Transmission Revenues pursuant to A.A.C. R14-2-1607(D) and Commission  
 11 Decision No. 60977 (June 22, 1998).

12 2. AEPCO's filing sought approval of a RAC and a CTC based on the "transition  
 13 revenue" or "financial integrity" method authorized by Decision No. 60977, as modified by Decision  
 14 No. 61677 (April 27, 1999).

15 3. Pursuant to Procedural Order dated January 3, 2000, a hearing was held on February  
 16 28, and 29, 2000.

17 4. AEPCO, AECC, Mohave and Staff presented evidence at the hearing. North Star  
 18 cross-examined witnesses.

19 5. As of December 31, 1999, AEPCO had regulatory assets totaling \$21,849,000.

20 6. Commission Decision No. 60977 recognizes that the recovery of regulatory assets  
 21 should be assured.

22 7. AEPCO proposed to amortize its Regulatory Assets over 11 years, which results in a  
 23 RAC of 1.55 mills per kWh in the first year. The RAC gradually declines to .21 mills in 2012.  
 24 AEPCO's RAC, as calculated in Exhibit A hereto, and incorporated by reference, is reasonable and in  
 25 accord with Commission Decision No. 60977.

26 8. The RAC will be charged to all power sold in the Distribution Cooperatives' service  
 27 territories. The imposition of the RAC does not increase rates.

28 9. AEPCO proposed that to assure that there is no over-recovery of its regulatory assets,

1 the Commission authorize it to make appropriate adjustments to the Distribution Cooperative bills so,  
2 as to reduce the bill by the amount of the RAC in effect for any billing period during the amortization,  
3 term. In addition, AEPCO anticipates transferring its transmission assets to a newly formed  
4 cooperative known as Southwest Transmission, and requested that the Commission authorize,  
5 AEPCO to assign the RAC to Southwest Transmission if necessary to avoid accounting write-offs.

6 10. AEPCO requested a CTC based on the "transition revenue" or "financial integrity"  
7 method of Stranded Cost recovery as authorized in Decision Nos. 60977 and 61677.

8 11. AEPCO's transitional revenue is the difference between its total generation revenue  
9 requirement for the Distribution Cooperatives less total generation market price revenues, determined  
10 using a forecast of market price. The calculation methodology of AEPCO's CTC is set forth in  
11 Exhibit B, attached hereto and incorporated by reference.

12 12. In the first year commencing July 1, 2000, the parties have agreed that AEPCO's CTC  
13 should be \$.0091 per kWh based on a market price of generation of \$.030 per kWh and generation  
14 revenue from the Distribution Cooperatives of \$.0391 per kWh.

15 13. AEPCO and Staff recommended that AEPCO should be authorized to collect a CTC  
16 for a period of five years, or until July 1, 2005.

17 14. AEPCO's CTC will be applied to competitive power sales in the Distribution  
18 Cooperatives' service territories.

19 15. North Star has a special three-party contract with Mohave and AEPCO for Mohave to  
20 provide North Star with non-firm power. Neither AEPCO or Mohave were required to build or  
21 contract for long term generation to serve North Star. North Star's load is fully interruptible and  
22 served by market generation sources which North Star has the ultimate discretion to select. Under the  
23 contract Mohave and AEPCO purchase the energy from the sources North Star selects and transmits  
24 and delivers the energy to North Star. For their services, AEPCO and Mohave recover actual costs  
25 incurred and receive a combined 15 percent margin markup.

26 16. Staff recommended that AEPCO's CTC should not apply to North Star because  
27 AEPCO has never made power supply commitments to serve North Star and thus had no expectation  
28 of continuing generation revenues from this customer.

1           17.     AEPCO argued North Star should be assessed the CTC and RAC and maintained that  
2 the North Star issues should be deferred to Mohave's stranded cost proceeding.

3           18.     AEPCO has reached agreement with Phelps Dodge and Trico, the parties to two  
4 special purchase contracts, that in the event Phelps Dodge takes power from any supplier other than  
5 AEPCO during the period the CTC is in effect, Phelps Dodge will pay 75 percent of AEPCO's  
6 authorized CTC then in effect, and the full amount of the RAC. Furthermore, the parties agreed that  
7 the rate paid under the contract would be increased, subject to Commission approval. A copy of the  
8 agreement among AEPCO, Phelps Dodge and Trico is attached hereto as Exhibit C, and incorporated  
9 by reference.

10          19.     AEPCO has reached agreement with Chemical Lime, a special contract customer of  
11 AEPCO's that in the event Chemical Lime opts to take power from a supplier other than AEPCO  
12 while AEPCO's CTC is in effect, Chemical Lime will be responsible for 70 percent of the CTC then  
13 in effect. Chemical Lime will be responsible for 100 percent of AEPCO's RAC then in effect. .A  
14 copy of the agreement between AEPCO and Chemical Lime is attached hereto as Exhibit C, and  
15 incorporated by reference.

16          20.     Phelps Dodge and Chemical Lime are members of AECC. In light of the Settlement  
17 Agreements, AECC agreed to drop its opposition to AEPCO's stranded cost recovery plan.

18          21.     The Settlement Agreements among AEPCO, Trico, Phelps Dodge and Chemical Lime  
19 are reasonable and should be approved. Consequently, each year when AEPCO seeks to reset its  
20 CTC, it is reasonable to require AEPCO to first calculate the CTC in accordance with the  
21 methodology in Exhibit B, followed by the calculation of the Phelps Dodge and Chemical Lime  
22 CTCs.

23          22.     Except as agreed in the Settlement Agreement between Phelps Dodge, AEPCO and  
24 Trico, no AEPCO member or customer will receive a rate increase on account of AEPCO's stranded  
25 cost recovery plan.

26          23.     AEPCO is currently engaged in a restructuring process which will allow AEPCO's all-  
27 requirements members to elect to become partial-requirements members. Mohave raised the issue  
28 whether AEPCO's CTC should apply to power sold competitively for which a partial-requirements

1 member, and not AEPCO, has assumed the resource responsibility. The issue cannot be resolved  
2 until AEPCO's restructuring is complete. Consequently, the parties recommend that the CTC  
3 authorized herein may be examined and, if appropriate, adjusted in a subsequent Commission  
4 proceeding dealing with AEPCO's restructuring in the case of an all-requirements member  
5 Distribution Cooperative which elects as part of the restructuring to become a partial-requirements  
6 member.

7 24. AEPCO proposed that the CTC authorized herein shall be subject to appropriate retail  
8 rate adjustments, if any, in subsequent Distribution Cooperative stranded cost proceedings.

### 9 CONCLUSIONS OF LAW

10 1. AEPCO is a public service corporation within the meaning of Article XV of the  
11 Arizona Constitution and A.R.S. §§ 40-202, -203, -250, -321, -322, -336, -361, -365, -367, and under  
12 the Arizona Revised Statutes, Title 40, generally.

13 2. The Commission has jurisdiction over AEPCO and the subject matter of this  
14 proceeding.

15 3. Notice of the proceeding was provided as required by law.

16 4. AEPCO's stranded cost recovery plan as described and modified herein is just and  
17 reasonable and in the public interest and should be approved.

18 5. The recommendations set forth in Findings of Fact Nos. 7, 9, 12, 13, 17, 18, 19, 21,  
19 23, and 24 are reasonable and should be adopted.

20 6. The Settlement Agreements attached hereto as Exhibit C are reasonable and in the  
21 public interest and should be approved.

### 22 ORDER

23 IT IS THEREFORE ORDERED that Arizona Electric Power Cooperative, Inc. is authorized  
24 an initial Regulatory Asset Charge of \$.00155 per kWh, to be charged to all power sold in Arizona  
25 Electric Power Cooperative, Inc.'s Class A Members' service territories commencing August 1,  
26 2000, and which charge shall decline each year as reflected in Exhibit A hereto through the year 2012  
27 or until the full amount of AEPCO's regulatory assets have been recovered.

28 IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. is authorized an

initial Competition Transition Charge of \$.0091 per kWh, to be applied to competitive power sales in the Class A Member distribution cooperatives' service territories commencing August 1, 2000, and which charge shall be adjusted annually after Commission approval, through July 1, 2005.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall file tariffs that comply with the authorizations granted herein by July 31, 2000.

IT IS FURTHER ORDERED that on May 1, 2001, and on each subsequent May 1 through 2004, AEPCO shall file reports with the Director of the Utilities Division that provide budget and market information sufficient to recalculate its Competition Transition Charge for the following year commencing July 1.

IT IS FURTHER ORDERED that the Regulatory Asset Charge approved herein is assignable to and may be collected by Southwest Transmission Electric Power Cooperative, Inc.

IT IS FURTHER ORDERED that the North Star related Competition Transition Charge and Regulatory Asset Charge issues shall be deferred for resolution in the Mohave Electric Cooperative stranded cost proceeding.

IT IS FURTHER ORDERED that the Settlement Agreements attached hereto as Exhibit C are approved.

IT IS FURTHER ORDERED that the Competition Transition Charge authorized herein may be examined, and, if appropriate, adjusted in a subsequent Commission proceeding dealing with AEPCO's restructuring in the case of an all-requirements member Distribution Cooperative which elects as part of the restructuring to become a partial-requirements member.

IT IS FURTHER ORDERED that the Competition Transition Charge authorized herein shall be subject to appropriate retail rate adjustments, if any, in subsequent Distribution Cooperative stranded cost proceeding.

...  
...  
...  
...  
...

1 IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall comply  
2 with Findings of Fact Nos. 7, 9, 12, 13, 17, 18, 19, 21, 23 and 24.

3 IT IS FURTHER ORDERED that this Decision shall become effective immediately.

4 BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

5  
6 

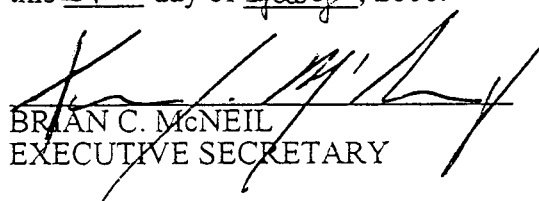
7 CHAIRMAN



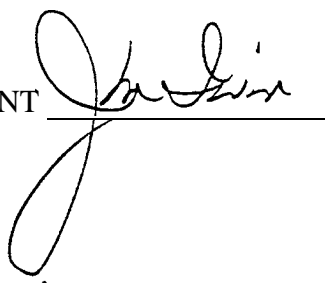
COMMISSIONER

COMMISSIONER

8  
9  
10 IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive  
11 Secretary of the Arizona Corporation Commission, have  
12 hereunto set my hand and caused the official seal of the  
13 Commission to be affixed at the Capitol, in the City of Phoenix,  
14 this 27<sup>th</sup> day of July, 2000.

  
BRIAN C. McNEIL  
EXECUTIVE SECRETARY

15  
16 DISSENT  
JR:bbs



1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24  
25  
26  
27  
38

1 SERVICE LIST FOR: ARIZONAELECTRIC COOPEARTIVE, INC.

2 DOCKETNO . E-01773A-99-0470

3  
4 Service List for RE-00000C-94-O 165

5 Lyn Farmer, Chief Counsel  
6 LEGAL DIVISION  
7 1200 W. Washington Street  
8 Phoenix, Arizona 85007

9 Deborah Scott, Director  
10 ARIZONA CORPORATION COMMISSION  
11 1200 W. Washington Street  
12 Phoenix, Arizona 85007

13

14

15

16

17

18

19

20

21

22

23

24

25

26

27

28

29

30

31

EXHIBIT A

Arizona Electric Power Cooperative, Inc.  
Calculation of Regulatory Assets - \$000

	Current Asset, Period	Projected Dec:01	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
<b>Regulatory Asset Listing and Proposed Recovery Period</b>															
<b>1. Debt Related Regulatory Assets</b>															
a) 1995 FFB Repricing	2012	1,315	101	101	101	101	101	101	101	101	101	101	101	101	101
b) 1994 FFB Repricing	2011	4,012	401	401	401	401	401	401	401	401	401	401	401	401	401
c) 1993 FFB Repricing	2012	4,092	315	315	315	315	315	315	315	315	315	315	315	315	312
d) Cooperative Utilities Trust Certificate	2010	1,929	150	150	150	150	150	150	150	150	150	150	150	150	153
Total Company Debt Related Regulatory Assets		12,148	985	985	985	985	965	985	985	985	985	985	985	965	961
less: Debt Related Regulatory Assets - Transmission		(2,037)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(131)
Total Debt Related Regulatory Assets - Generation		0,311	740	740	740	740	740	740	740	740	740	740	740	740	430
<b>2. Carbon Coal Regulatory Asset</b>															
	2007	12,530	1,507	1,507	1,581	1,581	1,567	1,561	1,581	1,509	0	0	0	0	0
<b>3. Total Regulatory Asset Recovery</b>		<b>21,849</b>	<b>2,307</b>	<b>2,307</b>	<b>2,307</b>	<b>2,301</b>	<b>2,307</b>	<b>2,307</b>	<b>2,301</b>	<b>2,309</b>	<b>740</b>	<b>740</b>	<b>740</b>	<b>740</b>	<b>430</b>
<b>Projected Class A Loads &amp; Calculation of Dollars per kWh</b>															
Class A Loads - DWh (see Footnote #1)			1,493	1,541	1,591	1,640	1,687	1,731	1,781	1,820	1,868	1,903	1,913	1,962	2,022
Dollars per kWh Class A Loads			0.00155	0.00150	0.00145	0.00141	0.00137	0.00133	0.00130	0.00127	0.00040	0.00039	0.00038	0.00037	0.00021

Exhibit B  
 ARIZONA ELECTRIC POWER COOPERATIVE, INC.  
 Calculation of Transitional Revenue (excl Regulatory Assets) - \$000's  
 Estimated Year 2000

<u>1. Revenue Requirement Calculation Class A (excl Anza)</u>	
<u>Operating Expenses - Apache Station and Purchase Power</u>	
Fuel Expense - Steam	33,418
Fuel Expense - Gas Turbine	1,603
Steam Turbine Operations	6,502
Steam Turbine Maintenance	8,331
Gas Turbine Operations	45
Gas Turbine Maintenance	38
Purchased Power	<u>25,181</u>
Subtotal	75,117
Administration, Depreciation & Taxes	7,750
A&G Allocation (7.65%)	6,684
Depreciation	<u>4,656</u>
Taxes, Other than Income	19,120
Subtotal	19,120
Interest Expense and Interest Income - (76.65%)	15,159
Interest on Long-term Debt	325
Debt Issuance Costs	<u>-2,565</u>
Interest Income	12,949
Subtotal	12,949
<u>Debt Service Coverage (DSC) Requirement</u>	<u>5,059</u>
DSC Requirement	5,059
Total Generation Revenue Requirement	<u>112,245</u>
<u>Less Non-jurisdictional Revenue (Generation Only)</u>	
Anza	1,552
Other Non-Jurisdictional Revenue - Firm (excl. Transmission)	42,243
Other Non-Jurisdictional Revenue - non-firm (excl. Transmission)	<u>11,286</u>
Subtotal	55,381
Total Generation Revenue Requirement Class A (excl Anza)	<u>56,864</u>
Actual Dollars per KWh - Class A Loads (excl Anza)	0.0391
<u>2. Market Price Revenue Calculation</u>	
Class A Loads (excl Anza)	1,453
Estimated Market Price \$/MWh	30.00
Total Generation Market Price Revenues	43,590
<u>3. Transition Revenue</u>	
Total Generation Revenue Req. Class A (excl Anza)	56,856
Less: Total Generation Market Price Revenues	<u>43,590</u>
Transition Revenue	13,274
Dollars per KWh CTC - Class A Loads (excl Anza)	.0091

EXHIBIT C

SETTLEMENT AGREEMENT

This Agreement is entered into this 19<sup>th</sup> day of May, 2000 among Phelps Dodge Corporation, formerly known as Cyprus Sierrita Corporation ("PD Sierrita"), Arizona Electric Power Cooperative, Inc. ("AEPSCO") and Trico Electric Cooperative, Inc. ("Trico") (collectively referred to as the "Parties").

Whereas, AEPSCO, Trico and PD Sierrita, as the successor-in-interest to Cyprus Sierrita Corporation, are parties to that certain Purchase Agreement dated April 22, 1994, as amended ("Purchase Agreement") and that certain Contingent Well Service Agreement dated April 12, 1996, as amended ("Well Agreement"); and

Whereas, PD Sierrita individually and as a member of Arizonans for Electric Choice and Competition ("AECC") has intervened in opposition to AEPSCO's request for approval of its filing as to regulatory assets and transition revenues in Docket No. E-0 1773A-98-0470 (the "Stranded Cost Case") before the Arizona Corporation Commission ("Commission"); and

Whereas, the Parties have agreed to settle their differences as to the Stranded Cost Case and with certain contract modifications on the basis as outlined herein.

Now, therefore, the Parties agree as follows:

1. PD Sierrita, AEPCO and Trico agree that the competition transition charge (“CTC”) for AEPCO as to the Purchase Agreement shall be 75% of the AEPCO CTC approved by the Commission (as the same may be reset) applied against all kWh’s taken up to and including the energy equivalent of five (5) MW at a 100% monthly load factor. The Parties further agree that the CTC for AEPCO as to the Well Agreement shall be 75% of the AEPCO CTC approved by the Commission (as the same may be reset) applied against all kWh’s taken. The CTC’s specified herein for PD Sierrita shall be in effect as of any day that PD Sierrita takes service for the Purchase Agreement or Well Agreement loads from a power supplier other than AEPCO and shall remain in effect and be paid by PD Sierrita so long as the AEPCO CTC is in effect.

2. The Parties agree that the Regulatory Asset Surcharge (“Surcharge”) approved by the Commission shall be in effect as to all kWh’s taken monthly as of any day that PD Sierrita takes service for the Purchase Agreement or Well Agreement loads from a power supplier other than AEPCO and shall be paid by PD Sierrita so long as the Surcharge is in effect.

3. As a further settlement term, the Parties have also agreed to increase AEPCO’s rates under the Purchase Agreement and Well Agreement, effective as of January 1, 2001 through the remaining term of these agreements. The Parties will promptly prepare, execute and file appropriate amendments reflecting such increase with the Commission for its approval.

4. PD Sierrita and AECC will promptly indicate in writing to the Parties, the Hearing Officer and the Commission in the Stranded Cost Case that the CTCs and Surcharge specified in paragraphs 1 and 2 should be approved by the Commission and should be authorized to be flowed through and collected from PD Sierrita in any subsequent Trico Stranded Cost proceeding. PD Sierrita and AECC will also promptly indicate in writing to the Parties, the Hearing Officer and the Commission their support for the approval by the Commission of the transition revenues and regulatory asset positions set forth by AEPCO in its Opening and Reply Memoranda in the Stranded Cost Case including without limitation AEPCO's proposal as to an initial CTC, its proposed CTC resetting procedure and its proposed Surcharge as reflected in Exhibit LS-RA. PD Sierrita and AECC will not take any position or action before the Commission which is inconsistent with the agreements and understandings set forth herein in the Stranded Cost Case or in any subsequent distribution cooperative Stranded Cost proceeding. AEPCO is authorized to file this Agreement with the Commission as evidence of these understandings and positions.

5. Each provision of this Settlement Agreement is in consideration and support of all the other provisions and is expressly conditioned upon acceptance and approval by the Commission without change. In the event the Commission fails to implement this Settlement Agreement according to its terms, this Settlement Agreement shall be deemed withdrawn and the Parties shall be free to pursue their respective positions in these proceedings without prejudice.

PHELPS DODGE CORPORATION,  
formerly known as Cyprus Sierrita  
Corporation

By \_\_\_\_\_  
Its \_\_\_\_\_

ARIZONA ELECTRIC POWER  
COOPERATIVE, INC.

By *Donald W. Kimball*  
Its *Exec. V.P. & CEO*

TRICO ELECTRIC COOPERATIVE, INC.

By \_\_\_\_\_  
Its \_\_\_\_\_

Accepted and Agreed:  
Arizonans for Electric Choice and Competition

By \_\_\_\_\_  
Its \_\_\_\_\_  
10421-0010/835861

PHELPS DODGE CORPORATION,  
formerly known as Cyprus Sierrita  
Corporation

MDM By W S Bank  
Its Vice President, Engineering

ARIZONA ELECTRIC POWER  
COOPERATIVE, INC.

BV  
Its

TRICO ELECTRIC COOPERATIVE, INC.

By  
Its

Accepted and Agreed:  
Arizonans for Electric Choice and Competition

By [Signature]  
Its President  
10421-0010/835861

PHELPS DODGE CORPORATION,  
Formerly known as Cyprus Sierrita  
Corporation

By \_\_\_\_\_

Its \_\_\_\_\_

ARIZONA ELECTRIC POWER  
COOPERATIVE, NC.

By \_\_\_\_\_

Its \_\_\_\_\_

TRICO ELECTRIC COOPERATIVE, NC.

By *Bob L. Spain*

Its *Vice Pres.*

Accepted and Agreed:  
Arizonans for Electric Choice and Competition

By \_\_\_\_\_

Its \_\_\_\_\_

SETTLEMENT AGREEMENT

This Agreement is entered into this 16<sup>th</sup> day of May, 2000 between Chemical Lime Company of Arizona, formerly known as Chemstar, Inc. ("Chemical Lime") and Arizona Electric Power Cooperative, Inc. ("AEPSCO") (collectively referred to as the "Parties").

Whereas, AEPSCO and Chemical Lime are parties to that certain Peak Load Shedding Agreement dated October 10, 1989; and

Whereas, Chemical Lime as a member of Arizonans for Electric Choice and Competition ("AECC") has intervened in opposition to AEPSCO's request for approval of its filing as to regulatory assets and transition revenues in Docket No. E-O 1773A-98-0470 (the "Stranded Cost Case") before the Arizona Corporation Commission ("Commission"); and

Whereas, the Parties have agreed to settle their differences as to the Stranded Cost Case on the basis as outlined herein.

Now, therefore, the Parties agree as follows:

1. Chemical Lime and AEPSCO agree that the competition transition charge ("CTC") for AEPSCO in relation to the Chemical Lime load shall be 70% of the AEPSCO CTC approved by the Commission (as the same may be reset) applied against all kWh's

taken. It shall be in effect as of any day that Chemical Lime takes power from a power supplier other than AEPCO and shall remain in effect and be paid by Chemical Lime so long as the AEPCO CTC is in effect.

2. The Parties agree that a Regulatory Assets Surcharge ("Surcharge") approved by the Commission shall be in effect as to all kwh's taken as of any day that Chemical Lime takes service from a power supplier other than AEPCO and shall be paid by Chemical Lime so long as the Surcharge remains in effect.

3. Chemical Lime and AECC will promptly indicate in writing to the parties, the Hearing Officer and the Commission in the Stranded Cost Case that (a) the CTC and Surcharge specified in paragraphs 1 and 2 should be approved by the Commission and should be authorized to be flowed through and collected from Chemical Lime in any subsequent Mohave Electric Cooperative stranded cost proceeding and (b) they support the approval by the Commission of the transition revenues and regulatory asset positions set forth by AEPCO in its Opening and Reply Memoranda in the Stranded Cost Case including without limitation AEPCO's proposal as to an initial CTC, its proposed CTC resetting procedure and its proposed Surcharge as reflected in Exhibit LS-RA. Chemical Lime and AECC will not take any position or action before the Commission which is inconsistent with the agreements and understandings set forth herein in the Stranded Cost Case or in any subsequent distribution cooperative stranded cost proceeding. AEPCO is authorized to file this Agreement with the Commission as evidence of these understandings and positions.



CHEMICAL LIME COMPANY OF  
ARIZONA, formerly known as Chemstar,  
Inc.

By \_\_\_\_\_  
Its \_\_\_\_\_

ARIZONA ELECTRIC POWER  
COOPERATIVE, INC.

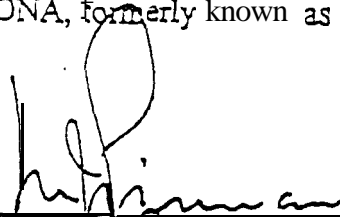
By *Ronald Kimball*  
Its *Exec. V.P. & CEO*

Accepted and Agreed:  
Arizonans for Electric Choice and Competition

By \_\_\_\_\_  
Its \_\_\_\_\_

10421-0010/835878

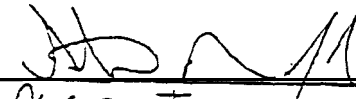
CHEMICAL LIME COMPANY OF  
ARIZONA, formerly known as Chemstar,  
Inc.

By   
Its Dir. of Purchasing

ARIZONA ELECTRIC POWER  
COOPERATIVE, INC.

BY \_\_\_\_\_  
Its \_\_\_\_\_

Accepted and Agreed:  
Arizonans for Electric Choice and Competition

By   
Its President

10421-0010/835873

CARL J. KUNASEK  
CHAIRMAN  
JIM IRVIN  
COMMISSIONER  
WILLIAM A. MUNDELL  
COMMISSIONER



BRIAN C. McNEIL  
EXECUTIVE SECRETARY

ARIZONA CORPORATION COMMISSION

## Dissenting Opinion

Docket No. E-01773A-98-0470  
Arizona Electric Power Cooperative – Stranded Cost Determination  
Decision No. 62758

This is a case of the Arizona Electric Power Cooperative (AEPCO) having their cake and eating it too. Less than one week ago, Judge Cohn Campbell granted AEPCO's motion for summary judgment (in part) in the case of Tucson Electric Power v. Arizona Corporation Commission, on the grounds that, "the [electric competition] rules are invalid for failure to provide for the Commission ascertaining the fair value of property of public service corporations under Article 15, section 3" of the Arizona Constitution. Indeed, AEPCO argued that because there was no provision in the Electric Competition Rules for the consideration of a finding of fair value of property, they were invalid.

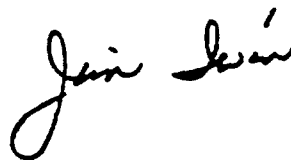
Six days after Judge Campbell issued his minute entry order, AEPCO came before the Commission seeking an approval of its filing as to regulatory assets and transition revenues, including a stranded cost determination. My simple question to AEPCO's attorney was whether a fair value determination was made concerning the Cooperatives' property. He responded that no fair value determination was made during the proceedings. I then questioned the attorney how AEPCO can ask this Commission to proceed on its application without a finding of fair value, when less than one week earlier it was successful in invalidating the Commission's

Electric Competition Rules -- based on the argument that they violated the Arizona Constitution for failure to provide for an ascertainment of fair value? His smile was all the answer I needed.

Today's decision to approve AEPCO's stranded cost filing defies common sense, especially in light of Judge Campbell's minute entry order granting (in part) the company's motion for summary judgment. I find it highly disingenuous for an entity to -- on the one hand -- seek, and apparently succeed, to invalidate this Commission's rules governing electric competition, while on the other hand seek approval of its stranded cost filing (money to be paid by its customers as a result of competition) based on those same exact set of rules.

For the reasons noted above, I must respectfully dissent.

Dated: July 26, 2000



---

Jim Irvin, Commissioner  
Arizona Corporation Commission

