OPEN MEETING ITEM

ORIGINAL

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

ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
NOV 23 2010
DOCKETED BY

DATE: NOVEMBER 23, 2010

DOCKET NO.: E-01773A-09-0472

TO ALL PARTIES:

Enclosed please find the recommendation of Administrative Law Judge Jane L. Rodda. The recommendation has been filed in the form of an Opinion and Order on:

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
(RATES)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by filing an original and thirteen (13) copies of the exceptions with the Commission's Docket Control at the address listed below by **4:00** p.m. on or before:

DECEMBER 2, 2010

The enclosed is NOT an order of the Commission, but a recommendation of the Administrative Law Judge to the Commissioners. Consideration of this matter has tentatively been scheduled for the Commission's Open Meeting to be held on:

DECEMBER 14, 2010 and DECEMBER 15, 2010

For more information, you may contact Docket Control at (602) 542-3477 or the Hearing Division at (602)542-4250. For information about the Open Meeting, contact the Executive Director's Office at (602) 542-3931.

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ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01773A-09-0472 DECISION NO. ____________ **OPINION AND ORDER**

DATE OF HEARING:	October 25, 2010
PLACE OF HEARING:	Tucson, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda
APPEARANCES:	Mr. Michael M. Grant, GALLAGHER & KENNEDY, P.A., on behalf of Arizona Electric Power Cooperative, Inc.; Mr. Michael Patten, ROSHKA DEWULF & PATTEN, P.L.C., on behalf of Trico Electric Cooperative, Inc.; Mr. Bradley S. Carroll, SNELL & WILMER, L.L.P., on behalf of Sulphur Springs Valley Electric Cooperative, Inc.; Mr. William P. Sullivan, CURTIS, GOODWIN, SULLIVAN, UDALL & SCHWAB, P.L.C., on behalf of Mohave Electric Cooperative, Inc.; and Ms. Maureen A. Scott, Senior Staff Counsel, Ms. Ayesha Vohra, and Mr. Scott M. Helsa, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Arizona Corporation Commission ("Commission") finds, concludes, and orders that:

FINDINGS OF FACT

1. On October 1, 2009, Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Cooperative") filed with the Commission an application for a rate increase.

2. In AEPCO's last rate case, the Commission ordered AEPCO to file a rate case six months after Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") completed a full calendar year as a Partial Requirements Member ("PRM") of AEPCO.[1] Pursuant to the terms of Decision No. 68071, AEPCO would have had to file its rate case by July 1, 2009. On April 13, 2009, AEPCO requested an extension to file its rate case until October 1, 2009, in order to allow AEPCO and its members to reach an agreement about cost allocation issues between the PRMs and All Requirements Members ("ARMs"). In Decision No. 71112 (June 5, 2009), the Commission granted the extension and authorized AEPCO to delay its rate case filing to October 1, 2009, using a test year ending March 31, 2009.

3. On November 2, 2009, the Commission's Utilities Division Staff ("Staff") notified the Cooperative that its application was sufficient under the requirements outlined in A.A.C. R14-2-103, and classified the Cooperative as a Class A utility.

4. On November 9, 2009, Mohave Electric Cooperative, Inc. ("Mohave") filed an Application to Intervene in the Proceeding. Mohave is a PRM of AEPCO.

5. On November 13, 2009, Staff filed a Request for Procedural Schedule.

6. By Procedural Order dated November 23, 2009, the matter was set for hearing to commence on August 17, 2010, procedural deadlines were established, and Mohave's request to intervene was granted.

7. On December 1, 2009, AEPCO filed a request to modify the public notice, and Trico Electric Company, Inc. ("Trico") filed a request to intervene. At the time, Trico was an ARM of AEPCO.

8. By Procedural Order dated December 4, 2009, the form of public notice was modified.

9. On December 7, 2009, Trico's intervention was granted.

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[1] Decision No. 68071 (August 17, 2005).

10. On January 4, 2010, AEPCO filed an Affidavit of Mailing confirming that the public notice of the hearing was mailed to each of its members on December 2, 2009.

11. On January 27, 2010, SSVEC filed a request to intervene, which was granted on February 1, 2010.

12. On March 1, 2010, Mohave filed a Request for an Expedited Procedural Conference to Discuss Potential Changes to Procedural Schedule. Mohave asserted that since AEPCO filed its Application, Trico had elected to become a PRM, which was not reflected in the Application.

13. On March 3, 2010, AEPCO filed a Response to Mohave's Request for Expedited Procedural Conference, suggesting that it would be more productive to schedule a Procedural Conference after the parties had discussed relevant issues and a revised schedule.

14. On March 5, 2010, Trico filed a Response to Mohave's Request, agreeing with Mohave that a Procedural Conference was appropriate and opining that the current schedule would require only minor modification.

15. On March 10, 2010, SSVEC filed a Response to Mohave's Request, joining Mohave's and Trico's request for Procedural Conference after the parties have had a chance to confer.

16. On March 23, 2010, AEPCO filed Affidavits of Publication confirming that the notice of the hearing was published on January 11, and 27, 2010, in the *Arizona Daily Star*, the *Kingman Daily Miner*, the *Sierra Vista Herald* and the *Bisbee Daily Review*, and on January 13, 2010, and January 27, 2010, in the *Eastern Arizona Courier.*

17. The Commission received two written public comments opposing the rate increase.

18. On March 29, 2010, AEPCO filed a Motion to Continue its existing Fuel and Purchased Power Cost Adjustor ("FPPCA")[2] until a Commission Decision in this matter. AEPCO requested that the FPPCA continue until modified as part of this proceeding to avoid disruption in its application. The FPPCA approved in the last rate case became effective September 1, 2005, and expired on August 31, 2010 "unless extended by the Commission."[3] In addition, in approving the

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[2] In Decision No. 68071 (August 17, 2005), the Commission approved a Fuel and Purchased Power Cost Adjustor. In the current proceeding, AEPCO proposed a new adjustor mechanism, which it calls a "Purchased Power and Fuel Adjustment Clause" ("PPFAC"). Consequently, the existing adjustor mechanism is referred to as the FPPCA while the proposed adjustor is referred to as the PPFAC.

[3] Decision No. 68071 ¶35 (a).

FFPCA in Decision No. 68071, the Commission included a provision allowing AEPCO to request that the Commission review the efficacy of the FPPCA ("efficacy provision") when AEPCO submits any of its semi-annual FPPCA reports. [4]

19. On March 29, 2010, AEPCO also filed a Request for Procedural Conference to discuss the members' settlement agreement and a revised procedural schedule.

20. By Procedural Order dated March 31, 2010, a telephonic Procedural Conference was scheduled to commence on April 14, 2010. At the April 14, 2010, Procedural Conference, AEPCO and its members reported that they had reached agreement on filing a revised application.

21. On April 20, 2010, AEPCO filed an Amended Application, which revised its original request from a 2.41 percent revenue increase, to a 0.06 percent revenue decrease, based on a Debt Service Coverage of 1.275. The Amended Application was supported by the Supplemental Direct Testimonies of Mr. Gary Pierson and Mr. Gary Goble.

22. By Procedural Order dated May 3, 2010, the procedural schedule was revised, with a hearing set for October 25, 2010.

23. On May 27, 2010, AEPCO filed Notice of Publication of the Notice of Hearing in the *Currents* magazine and Certificates and Affidavits of Mailing Notice from Trico and Mohave. The Notice appeared in the March 2010, issue of *Currents* serving Anza Electric Cooperative, Inc. ("Anza"), Duncan Valley Electric Cooperative ("DVEC"), Electric District No. 2, Graham County Electric Cooperative ("GCEC"), Grand Canyon State Electric Cooperative and SSVEC. Trico mailed the Notice to its members in its March 2010, bill cycle, and Mohave mailed the Notice to its members on March 18, 2010.

24. On June 1, 2010, Trico filed the Direct Testimony of Vincent Nitido.

25. On June 2, 2010, AEPCO, Trico, SSVEC and Mohave filed a Joint Request for Contract/Amendments Approvals and Revised Rates Request. The cooperatives requested approval of a new Partial-Requirements Capacity and Energy Agreement between AEPCO and Trico; a Third Amendment to the Mohave PRM Agreement; the First Amendment to the SSVEC PRM Agreement;

[4] In 2008, AEPCO utilized the efficacy provision to seek Commission approval to shorten the back amortization period to six months when the 12 month period was not working efficiency. *See* Tr. at 14 and Decision No. 70354 (May 16, 2008).

the Ninth Amendment to the Wholesale Power Contract between AEPCO and DVEC; and the Seventh Amendment to the Wholesale Power Contract between AEPCO and GCEC (collectively the "Contracts"). The Contracts reflect the new PRM agreements between AEPCO and Trico, Mohave and SSVEC, and revise the ARM agreement between AEPCO and DVEC and GCEC. The Contracts allow for the implementation of the new revenues and rates being proposed in this docket.

26. On June 4, 2010, the Hearing Division issued a Recommended Order that would retain the existing FPPCA until further Order of the Commission.

27. On June 30, 2010, Staff filed a Motion of Extension of Time to File Staff Direct Testimony and Staff Rate Design Testimony, which was granted by Procedural Order dated July 7, 2010.

28. On July 2, 2010, Staff filed the Direct Testimony of Ralph Smith and Randall Vickroy.

29. On July 12, 2010, the Commission issued Decision No. 71777, which authorized the continuation of AEPCO's FPPCA until further order of the Commission.

30. On July 16, 2010, Staff filed the Direct Testimony of Dennis Kalbarczyk on Rate Design and Cost of Service.

31. On July 30, 2010, Staff filed the Direct Testimony of John Antonuk on the Prudence Review.

32. On August 6, 2010, Staff filed Replacement Direct Testimony on the Prudence Review.

33. On August 30, 2010, Mohave filed the Rebuttal Testimony of Carl Stover Jr.; AEPCO filed the Rebuttal Testimony of Gary Pierson and Gary Goble; and Trico filed the Rebuttal Testimony of Vincent Nitido.

34. On September 21, 2010, Staff filed the Surrebuttal Testimony of Ralph Smith, John Antonuk and Dennis Kalbarczyk.

35. On September 24, 2010, AEPCO requested a short extension of time to file Rejoinder Testimony, which was granted by Procedural Order of the same date.

36. On September 30, 2010, Staff filed a Notice of Filing of Possible Stipulation in

Resolution of Issues.

37. On October 6, 2010, Mohave filed the Rejoinder Testimony of Carl Stover Jr. and AEPCO filed the Rejoinder Testimony of Gary Pierson.

38. On October 13, 2010, AEPCO filed a Notice of Errata, correcting a typographical error in GEP-6 attached to Mr. Pierson's Rejoinder Testimony.

39. On October 18, 2010, the parties participated in a pre-hearing conference at which time they reported that they were close to agreement on all issues in this case and that they expected to file a stipulation reflecting their agreement prior to the hearing.

40. On October 21, 2010, the parties filed a Stipulation that resolved all issues in this case.

41. The hearing convened as scheduled on October 25, 2010, before a duly authorized Administrative Law Judge. Gary Pierson testified for AEPCO, Vincent Nitido testified for Trico and Barbara Keene testified for Staff in support of the Stipulation.

42. AEPCO is a non-profit, electric generation cooperative which provides the power needs of its three ARM and three PRM Class A Member distribution cooperatives.[5] The distribution cooperatives, in turn, provide electricity to their retail customer/members.

43. AEPCO's current rates were approved in Decision No. 68071.

44. In the test year ended March 31, 2009, AEPCO had operating income of $15,942,380, on total revenues of $178,762,679, resulting in a Debt Service coverage Ratio ("DSC") of 1.38 and a 7.5 percent rate of return on a Fair Value Rate Base ("FVRB") of $211,802,594.[6]

45. AEPCO's lender, the Rural Utilities Service ("RUS"), imposes debt covenants that require both a DSC and Times Interest Earned Ratio ("TIER") of at least 1.0 in two of three consecutive years.[7]

46. AEPCO experienced strong financial performance in each of the years 2007 through 2009, and has been able to increase its equity ratio from about 5 percent of total capital at the end of 2005, to 29.45 percent at the end of 2009.[8] By December 31, 2010, however, a series of significant

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[5] At the time it filed its Application, AEPCO's PRMs were Mohave and SSVEC; its ARMs were Trico, DVEC, GCEC and Anza. In the course of this proceeding, Trico elected to become a PRM.
[6] Ex S-1 Smith Direct at RCS-2.
[7] Ex S-2 Vickroy Direct at 3.
[8] *Id.* at 4.

business changes will affect AEPCO's financial outlook, including increased coal prices, the expiration of three large sales contracts to Class B members, and the expiration of a 100 MW contract with the Salt River Project which accounted for annual margins of $13.2 million.[9]

The Rate Request

47. In its October 1, 2009, Application, AEPCO requested a revenue increase of approximately $4.023 million, or a 2.41 percent increase in revenue. The proposed net increase was a blend of a 2.83 percent decrease in revenues from its ARMs and a 5.39 percent increase in the revenues from its PRMs. AEPCO's original filing was intended to produce a DSC" of 1.35 and operating income of approximately $3.4 million.[10]

48. In its April 20, 2010, Amended Application, AEPCO requested a net decrease in revenues of approximately $97,000, using a test year ended March 31, 2009, and based on a DSC of 1.28 and TIER of 1.305894.

49. In Direct Testimony, Staff's witness Vickroy testified that based on AEPCO's risk profile, an appropriate target range for AEPCO's DSC is 1.25 to 1.45.[11] Staff originally recommended total revenues of $178,993,693, an increase of $231,014, producing operating income of $16,173,394, a DSC of 1.4, and TIER of 1.5. Staff believed at the time, that AEPCO's proposed DSC of 1.275 was "too thin from both a net margin and cash flow perspective."[12]

50. After reviewing Staff's testimony and concerns about increased maintenance costs, AEPCO's Board decided to increase its revenue request to yield a DSC of 1.32, rather than the original 1.275.[13] AEPCO's rebuttal position produced operating income of $2.95 million as compared to Staff's recommended $4.35 million.[14]

51. Pursuant to the Stipulation, the parties, including Staff, agree and recommend that the Commission approve Operating Revenues of $177,590,362 based on a DSC of 1.32. The recommended revenue request results in a revenue decrease of $1,172,317, or 0.65 percent, over test

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[9] *Id.* at 2.

[10] When AEPCO filed its October 1, 2009, Application, discussions concerning cost allocations were on-going amongst its members, and the testimony filed with the application indicated that revisions were likely. *See* Tr. at 10.

[11] Ex S-2, Vickroy Direct at 15.

[12] Ex S-2 Vickroy Direct at 18; Ex S-1 Smith Direct at RCS-2.

[13] Ex A-4 Pierson Rebuttal at 4; Tr. at 42.

[14] Ex A-4 Pierson Rebuttal at 4.

year revenues, and results in operating income/margins of $14,770,063, and a 6.97 percent return on FVRB.[15]

52. The parties agree that AEPCO's test year FVRB is $211,802,594. AEPCO agreed to all of Staff's adjustments to rate base as set forth in the Direct Testimony of Ralph Smith.[16]

53. AEPCO did not request a Reconstruction Cost New Rate Base, and thus its FVRB is the same as its Original Cost Rate Base ("OCRB").

54. The parties' proposed FVRB is supported by the evidence and should be adopted.

55. Staff ultimately agreed with the Cooperative's assessment of its cash flow needs, and agreed to adopt a DSC of 1.32 as being appropriate. The agreed-upon DSC is in the middle of Staff's originally recommended range of reasonable DSCs.

56. Based on the entirety of the record, the parties' recommended revenue level of $177,590,362, is designed to yield adequate cash flow to meet the Cooperative's operating needs while considering the effect of rates on its member distribution cooperatives. As such, the parties' recommended revenue level is just and reasonable and should be adopted.

57. A copy of the proposed tariffs for the ARMs and the PRMs are attached hereto as Exhibits A and B, respectively, and incorporated herein by reference. The parties propose the following rates:

Description	
Collective All-Requirement Members (1)	
Demand Rate $/kW	N/A
Fixed Charge - $/mo	$238,793
O&M Charge - $/mo	$414,019
Energy Rates:	
Current Energy Rated $/kWh	
Base Resources $/kWh	$0.03156
Other Resources $/kWh	$0.06170
PPFAC Bases:	
Current $/kWh	
Base Resources $/kWh	$0.03361
Other Resources $/kWh	$0.07941

[15] *Id.* at Sch. GEP-2; Tr. at 72.
[16] Ex A-4 Pierson Rebuttal at 1.

Partial-Requirements Members:

Mohave Electric Cooperative

Fixed Charge $/mo	$727,283
O&M Charge $/mo (Present $/kW)	$1,274,882
Energy Rates:	
Current Energy Rates $/kWh	
Base Resources $/kWh	$0.03215
Other Resources $/kWh	$0.06879
PPFAC Bases:	
Current $/kWh	
Base Resources $/kWh	$0.03330
Other Resources $/kWh	$0.06971

Sulphur Springs Valley

Fixed Charge $/mo	$643,991
O&M Charge $/mo (Present $/kW)	$1,128,876
Energy Rates:	
Current Energy Rates $/kWh	
Base Resources $/kWh	$0.03229
Other Resources $/kWh	$0.06676
PPFAC Bases:	
Current $/kWh	
Base Resources $/kWh	$0.03337
Other Resources $/kWh	$0.07241

Trico Electric Cooperative

Demand Rate per kW	N/A
Fixed Charge $/mo	$646,435
O&M Charge $/mo (Present $/kW)	$764,465
Energy Rates:	
Current Energy Rates $/kWh	
Base Resources $/kWh	$0.03238
Other Resources $/kWh	$0.06604
PPFAC Bases:	
Current $/kWh	
Base Resources $/kWh	$0.03336
Other Resources $/kWh	$0.09084

1) The Fixed Charge and the O&M Charge will be apportioned among the Collective ARMs ("CARMs") and allocated to each CARM based upon each CARM's monthly Demand Ratio Share. The Demand Ratio Share will be calculated each month as the percentage of each CARM's 12-month rolling average demand to the total of CARMs' 12-month rolling average demand.

58. A summary comparing the total cost for each Class A member under existing and proposed rates follows:[17]

[17] Ex MEC-2 Stover Rejoinder at 8.

Class of Service	Energy(1) kWh	Billing MW	Present Revenue	Proposed Revenue	Change $	Change %
Anza	51,283,408	96,412	$3,353,127	$3,260,032	(93,095)	-2.78%
Duncan	28,079,760	57,180	1,901,744	1,858,064	(43,680)	-2.30%
Graham	156,396,015	324,562	10,683,325	10,446,493	(236,832)	-2.22%
Mohave	875,380,060	1,723,399	54,205,506	55,489,632	1,284,126	2.37%
SSVEC	847,038,000	1,629,806	52,026,365	52,370,038	343,673	0.66%
Trico	646,286,536	1,361,311	44,448,572	42,022,063	(2,426,509)	-5.46%
Total Class A	2,604,463,779	5,192,670	166,618,639	165,446,322	(1,172,317)	-0.70%

(1) Energy Values include total requirement based on AEPCO adjustments

Average Wholesale Rate	% Energy	$/MWh	$/MWh	$/MWh
Anza	1.97%	$65.38	$63.57	(1.82)
Duncan	1.08%	67.73	66.17	(1.56)
Graham	6.00%	68.31	66.80	(1.51)
Mohave	33.61%	61.92	63.39	1.47
SSVEC	32.52%	61.42	61.83	0.41
Trico	24.81%	68.78	65.02	(3.75)
Total	100.0%	63.97	63.52	(0.45)

59. Mr. Stover testified for Mohave that given the increase for Mohave of $0.00147/kWh, a residential customer using 1,000 kWh during the month would experience, on average, an increase of $1.60/month.[18]

60. Mr. Nitido testified for Trico that it supports AEPCO's request for a DSC of 1.32, as it will provide AEPCO with sufficient operating margins and allow the customer/members of the

[18] *Id.* at 8.

member distribution cooperatives to share in lower rates.[19] Mr. Nitido estimated that a Trico customer using 1,000 kWh/month will see a monthly decrease of approximately $4.00 as a result of AEPCO's proposed rates.[20]

61. AEPCO estimated that an ARM residential customer using 1,000 kWh/month would see about a $1.80 decrease, and a SSVEC customer using the same amount would see about a $0.50 increase.[21]

62. Trico is converting to a PRM in order to gain increased flexibility and access to economies of sale in meeting its customers' needs economically and responsively. Trico states that PRM status allows Trico to better meet its renewable energy and energy efficiency obligations under Commission rules.[22] Mr. Nitido testified that an ARM rate was not negotiated or proposed for Trico, and the settlement among the parties works only with Trico as a PRM. Thus, Trico urged the Commission to approve AEPCO's rates, Trico's Partial Requirements Capacity and Energy Agreement and the amendments to the ARMs' Wholesale Power Contracts in order for the comprehensive settlement among AEPCO and its members to be realized and to implement the allocation of costs among AEPCO's members.[23]

<u>The Contracts</u>

63. Subject to the prior approval of the RUS, the parties recommend that the Commission approve the Contracts as they are necessary to effect the rates agreed upon by the parties.

64. Staff reviewed the Contracts and agrees with AEPCO's allocated cost of service study.[24] Staff recommends approval of the Contracts.[25]

65. At the time of the hearing, the RUS was reviewing the Contracts. The parties expected that RUS approval would come before the first of the year. AEPCO states that it will file notice of RUS approval in the docket.[26]

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[19] Ex Trico-2, Nitido Rebuttal at 2.
[20] Tr. at 61.
[21] Ex. A-5 Pierson Rejoinder at 10-11.
[22] Ex Trico-1 Nitido Direct at 4.
[23] *Id.*
[24] Ex S-10 Kalbarczyk Surrebuttal at 5.
[25] Tr. at 74.
[26] Tr. at 31-32.

66. The parties propose that following RUS approval, their recommended rates go into effect on the first day of the month following the effective date of Commission approval.

67. The Contracts are fair and reasonable and are necessary to reflect the parties' agreements concerning the cost allocations for PRMs and ARMs.

68. The parties' stipulated rates are fair and reasonable and reasonably calculated to produce the approved revenue. Whether an individual member sees a rate increase or decrease is a function of the costs to serve that member.[27]

PPFAC

69. The Stipulation requests that the Commission approve a temporary surcharge mechanism to close out existing FPPCA bank balances by assessing a surcharge. They propose that the ARMs be assessed 1.123 mills per kWh and PRMs be assessed 1.68 mills per kWh until their individual under-collected balance is recovered.[28] If a member has an over-collected balance, credit will be made at the same rate.[29] Mr. Pierson testified that at the end of August 2010, the FPPCA balance was close to zero. [30]

70. In addition, the parties recommend that the Commission continue the existing efficacy provision with respect to the new PPFAC.

71. AEPCO recommends the first semi-annual adjustor for the new PPFAC be filed on September 1, 2011, to become effective on October 1, 2011. It would be based on data covering the 12 months ended June 30, 2011. Thereafter, AEPCO states it would make the fuel adjustor filings to become effective on April 1, and October 1, based upon the historical period of the prior 12 months.[31]

Prudence Review

72. Liberty Consulting Group ("Liberty") reviewed AEPCO's existing FPPAC, and found that AEPCO's proposed changes, which are intended to align amounts recovered from individual members more closely with the hourly costs they impose on AEPCO, are appropriate.[32] Liberty

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[27] Tr. at 49-50.
[28] Ex A-4 Pierson Rebuttal at 17.
[29] Tr. at 35.
[30] *Id.*
[31] Ex A-4, Pierson Rebuttal at 17-18.
[32] Ex S-4 Antonuk Direct at 14.

recommended a temporary surcharge to recover balances under the current FPPCA.

73. The results of Liberty's prudence review are set forth in the testimony of Mr. Antonuk. Liberty examined the prudence of fuel, purchased power and plant operations policies, and costs, and performed an engineering review. Liberty concluded:

a. AEPCO's fuel and energy management division is organized appropriately and the Cooperative has an appropriate set of procedures, policies, guidelines, approval authorities, and trading controls addressing technical and ethical performance.[33]

b. AEPCO's fuel procurement has been supported by reasonable consumption forecasts and it has pursued coal resales and swaps to produce savings for members and mitigate the effects of increased rail costs. AEPCO has appropriately developed and maintained its gas-supply relations, but Liberty believes that AEPCO should solicit interest from other suppliers in order to assure that its traditional sources continue to offer the best available terms.[34]

c. With respect to fuel supply management, AEPCO applies appropriate processes and procedures for the weighing, sampling, and analysis of coal shipments to Apache Station.[35]

d. Gas supply management is generally effective, but Liberty did not find significant performance measurements for gas traders.[36]

e. With respect to gas hedging, AEPCO's objective is appropriate, and its personnel adequately qualified, although AEPCO does not formally assess its effectiveness in meeting its objectives.[37]

f. With respect to power transactions, AEPCO effectively manages the scheduling, real-time dispatch, and trading functions associated with making power purchases and sales, but AEPCO's large members fail to provide AEPCO on a timely basis with the pre-scheduling information that it needs to produce its daily day-ahead

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[33] *Id.* at 4.
[34] *Id.* at 4.
[35] *Id.* at 6.
[36] *Id.* at 7.
[37] *Id.* at 7-8.

schedule, and AEPCO's internal audit reports show insufficient attention to detail regarding the FPPCA.[38]

g. With respect to the engineering and plant operations, AEPCO's technical performance, personnel and facilities are generally sound and its management team is capable, knowledgeable and supported with appropriate tools. Liberty found, however, that AEPCO faces significant questions about the future of its coal-fired units which have functioned for 30 years in base-load mode, but which now appear more likely to cycle because of the decline in the market competitiveness of these units. Increased unit cycling may be having impacts on equipment, contributing to a significant drop in availability in 2009.[39]

h. AEPCO employs good practices in preparing for and managing outages, however, its consistent overruns in outage durations is not typical, and warrants a structured examination and adopting a more formal and structured approach that would remain consistent with the comparatively small size of AEPCO's fleet. Liberty found that the Apache Station suffers a particularly high number of trips due to personnel errors.[40]

74. Liberty recommends:

a. AEPCO should solicit interest from additional suppliers beyond its traditional sources for AEPCO's forward gas purchases.[41]

b. External circumstances have caused AEPCO's coal inventories to reach unacceptable levels (135 days at the end of 2009), and AEPCO needs to develop a strategy to address the situation.[42]

c. With respect to fuel supply management, AEPCO should undertake a formal process for examining the causes of differences between physical and book inventory, and take corrective action as appropriate; should develop a plan for

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[38] *Id.* at 8-10.
[39] *Id.* at 10-11.
[40] *Id.* at 12.
[41] *Id.* at 5.
[42] *Id.* at 6.

reducing the coal inventory level at the Apache Station, and should explore creating a set of specific performance measures for its traders.

d. At a minimum, AEPCO should conduct annual assessments to determine whether the hedging program is meeting its stated objective, and the internal Audit Group should periodically review the processes and systems for tracking transactions.[43]

e. AEPCO should require its PRMs and Salt River Project to make timely submissions of pre-scheduling power requirements and AEPCO should undertake a series of steps to assure the Commission that it has effectively completed, can demonstrate, and will periodically audit the effectiveness of the new adjustment clause processes.[44]

f. AEPCO should conduct a study of the future role of the Apache Station and how that role relates to member needs for future power supply; should examine methods to create more structured and formal outage planning and management; and examine the root causes of trips resulting from personnel errors.[45]

75. In the Stipulation, the parties agree that AEPCO should file an action plan on Liberty's recommendations by February 1, 2011, with the reporting and confidentiality provisions as set forth in Mr. Pierson's Rejoinder Testimony.[46]

76. The parties' agreement concerning the Prudence Review and AEPCO's response thereto is reasonable and should be adopted.

77. Based on the record, the Stipulation is fair and reasonable and in the public interest and should be approved.

78. The Contracts provide for a fair and equitable allocation of costs and revenues among the PRMs and ARMs based on principles of cost causation, while providing AEPCO with fair and reasonable recovery of its revenue requirements and sufficient operating margins. As such, the Contracts are fair and reasonable and in the public interest and should be approved conditioned upon

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[43] *Id.* at 7-8.
[44] *Id.*at 10.
[45] *Id.* at 13.
[46] Ex A-5 Pierson Rejoinder at 2-4.

RUS approval.

CONCLUSIONS OF LAW

1. AEPCO is a public service corporation pursuant to Article XV of the Arizona Constitution and A.R.S. §§ 40-250 and 40-251.

2. The Commission has jurisdiction over AEPCO's operations and the subject matter of the Application.

3. Notice of the proceeding was provided in conformance with law.

4. AEPCO's FVRB is $211,802,594.

5. The rates, charges and conditions of service and Contracts approved herein are just and reasonable and in the public interest.

ORDER

IT IS THEREFORE ORDERED that the rates schedules and Purchased Power And Fuel Adjustment Clause for the ARMs and PRMs as set forth in Exhibits and A and B attached hereto are approved, and Arizona Electric Power Cooperative Inc. is hereby authorized and directed to file with the Commission, on or before December 31, 2010, revised tariffs consistent therewith.

IT IS FURTHER ORDERED that the rates and charges approved herein shall be effective for all service provided on and after January 1, 2011, or the first of the month following RUS approval of the Partial-Requirements Capacity and Energy Agreement between Arizona Electric Power Cooperative, Inc. and Trico Electric Cooperative, Inc., the Third Amendment to the Mohave Electric Cooperative Partial Requirements Agreement; the First Amendment to the Sulphur Springs Valley Electric Cooperative, Inc. Partial Requirements Agreement; the Ninth Amendment to the Wholesale Power Contract between Arizona Electric Power Cooperative and Duncan Valley Electric Cooperative; and the Seventh Amendment to the Wholesale Power Contract between Arizona Electric Power Cooperative, Inc. and Graham County Electric Cooperative, Inc., whichever is later.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. is authorized to establish a surcharge to collect and/or refund the existing under- or over-collected balances in its existing Fuel and Purchased Power Cost Adjustor bank account as described herein and as set forth in detail in the Rejoinder Testimony of Mr. Pierson.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. may file a request that the Commission review the efficacy of the Purchased Power And Fuel Adjustment Clause with Arizona Electric Cooperative Inc.'s submission of any semi-annual report required by the tariff and this Decision.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall file an Action Plan on Liberty Consulting Group's Prudence Review recommendations by February 1, 2011, and shall file quarterly updates on each item in the Action Plan, until all action items have been completed.

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this _____ day of __________, 2010.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT ______________________

DISSENT ______________________

SERVICE LIST FOR: ARIZONA ELECTRIC POWER COOPERATIVE, INC.

DOCKET NO.: E-01773A-09-0472

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EXHIBIT A

Exhibit GEP-6

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

TARIFF

PERMANENT

Effective Date: January 1, 2011

AVAILABILITY

Available to all cooperative associations which are or shall be collective all-requirements Class A members ("CARM") of the Arizona Electric Power Cooperative, Inc. ("AEPCO").

MONTHLY RATE (BILLING PERIOD)

Electric power and energy furnished under this Tariff will be subject to the rates set forth in the attached Exhibit A and the terms set forth herein in addition to any applicable terms set forth in the Member's Wholesale Power Contract.

Billing Month – The first calendar month preceding the month the bill is rendered.

Demand Overrun Adjustment – If, in any hour, the CARM's metered load exceeds its Allocated Capacity, then AEPCO shall compute a Demand Overrun Adjustment for the CARM and each Member shall be charged a portion of such Demand Overrun Adjustment in proportion to that Member's demand ratio share. Such Demand Overrun Adjustment shall equal the product of the CARM's Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((mbdkW) / AC) - 1$$

Where:

doaf	=	Demand Overrun Adjustment Factor,
mbdkW	=	Metered kW of CARM, and
AC	=	Allocated Capacity of CARM, in kW.

In addition, Member shall pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Resources Energy Rate.

Power Factor – Each Member shall maintain Power Factor at the time of maximum demand as close to unity as possible. If the Power Factor of Member measured at the aggregated Member's Delivery Point(s) at the time of Member peak demand is outside a bandwidth of 95% leading to 95% lagging, a Power Factor Adjustment shall be separately charged to the Member. The Power Factor Adjustment shall be the product of the Member's power factor adjustment (as set forth below) multiplied by the quotient of the Member's demand ratio share of the CARM O&M Charge divided by the sum of the CARM's 12-month rolling average demand. The power factor adjustment shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW	=	power factor adjustment in kW,
mkW	=	Member Metered kW,
mpf	=	measured power factor at the time of Member peak demand, and
bpf	=	0.95.

The provisions of the power factor adjustment may be waived if power factor is detrimentally impacted as a direct result of system improvements or a change in operational procedure by AEPCO to reduce transmission losses and/or improve system reliability.

Capacity and Energy Below Allocated Capacity – If CARM is utilizing a Future Resource, Supplemental Purchase or S&G PPA in any hour to serve Native Load and CARM fails to take its required share of Minimum Base Capacity or Minimum Other Capacity, CARM shall pay a charge as set forth in Section 2.4 of Rate Schedule A to the Member's Wholesale Power Contract.

Taxes – Bills rendered are subject to adjustment for all federal, state and local government taxes or levies, including any taxes or levies imposed as a carbon tax or "cap and trade" or other carbon assessments system imposed on electricity sales or electricity production and any assessments that are or may be imposed by federal or state regulatory agencies on electric utility gross revenues.

Transmission and Ancillary Service Charges – Each Class A member shall also be billed by AEPCO for charges AEPCO incurs for the transmission of power and energy to the Class A member's delivery point(s). Such charges will be assessed to the Class A member at the rates actually charged AEPCO by the transmission provider and others for transmission service and the provision of ancillary services.

Power Cost Adjustor Rates

"Base Resources" are defined as (1) AEPCO's Steam Turbine Units 2 and 3, (2) power purchased under contract from the Western Area Power Administration and (3) economy purchases displacing base resources generation.

"Other Resources" are defined as (1) AEPCO's generation units other than Steam Turbine Units 2 and 3, (2) power purchased under contracts which serve the combined scheduled loads of AEPCO's Class A members plus power purchased under contract and economy energy purchases (other than economy purchases displacing base resources generation) made for the purpose of meeting the scheduled load requirements of all Class A members and (3) power purchased under contracts or resources which have been acquired to serve Class A Member load and which the Member has expressly agreed to in a participation agreement.

The monthly bill computed under this Tariff shall, using the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh derived from each resource type by the applicable Power Cost Adjustor Rate for Base Resources and Other Resources where:

Base Resources Adjustor Rate

BF = (BPC + BBA) - \$.003361

BF = Base Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent (\$0.00001).

BPC = The Commission-allowed pro forma fuel costs of Base Resources generation, the purchased power costs of Base Resources and wheeling costs associated with Base Resources in dollars per kWh, rounded to the nearest one-thousandth of a cent (\$0.00001).

BBA = The "Base Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent (\$0.00001) over- or under-collected in the past from Base Resources. The BBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Base Resources kWh energy sales.

Allowable Base Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 2 and 3 as recorded in RUS Account 501, plus

B. The actual costs associated with Base Resources power purchased for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis to substitute for higher cost Base Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Base Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the collective all-requirements Class A members, less

E. The demand and energy costs recovered through non-tariff contractual firm sales of Base Resources power and energy as recorded in RUS Account 447, less

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Base Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

Other Resources Adjustor Rate

OF = (OPC + OBA) - $0.07941

OF = Other Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

OPC = The Commission-allowed pro forma fuel costs of Other Resources generation, Other Resources purchased power and wheeling costs associated with Other Resources in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

OBA = The "Other Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Other Resources. The OBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Other Resources kWh energy sales.

Allowable Other Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 1, 4, 5 and 6 as recorded in RUS Accounts 501 and 547, plus

B. The actual costs associated with Other Resources purchased power for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of Other Resources energy purchased when such energy is purchased on an economic dispatch basis. Included therein are such costs as those charged for economy energy purchases and the charges resulting from a scheduled outage of Other Resources generation units. All such kinds of Other Resources energy being purchased by AEPCO to substitute for its own higher cost Other Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Other Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the collective all-requirements Class A members, less

E. The demand and energy costs recovered through non-tariff contractual firm sales of Other Resources power and energy as recorded in RUS Account 447, less

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Other Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Power Cost Adjustor Rates as specified herein based upon a rolling 12-month average of allowable fuel, purchased power and wheeling costs for the BPC and the OPC plus the bank balance amortization component for the BBA and OBA. AEPCO shall initially file by September 1, 2011 and thereafter on March 1 or September 1 of the month preceding the effective date of the revised Power Cost Adjustor Rates (i.e., April 1 or October 1): (1) calculations supporting the revised Adjustor Rates with the Director, Utilities Division, and (2) a Tariff reflecting the revised Adjustor Rates with the Commission which shall be effective for billings after the first day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

EXHIBIT A

Effective Date	January 1, 2011*
Collective All-Requirements Members:	
Total Fixed Charge/Month	$238,793**
Total O&M Charge/Month	$414,019**
Base Resources Energy Rate – $/kWh	$0.03156
Other Resources Energy Rate – $/kWh	$0.06170

Base Resources Power Cost Adjustor Rate – $/kWh $0.00000***
Other Resources Power Cost Adjustor Rate – $/kWh $0.00000***

* Rates are effective for service provided on and after this date.

** The Total Fixed Charge and the Total O&M Charge will be apportioned among the CARMs and allocated to each CARM based upon each CARM's monthly Demand Ratio Share. The Demand Ratio Share will be calculated each month as the percentage of each CARM's 12-month rolling average demand to the total of the CARMs' 12-month rolling average demand.

*** Effective January 1, 2011 and determined and revised as set forth in the Tariff.

EXHIBIT B

Exhibit GEP-7

Arizona Electric Power Cooperative, Inc.

Partial-Requirements Schedule
Rates and Fixed Charge
(Effective January 1, 2011)

Service provided to Mohave Electric Cooperative, Inc. ("MEC"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Trico Electric Cooperative, Inc. ("Trico") by the Arizona Electric Power Cooperative, Inc. ("AEPCO") under the Partial Requirements Capacity and Energy Agreements shall be at the rates set forth in the attached Exhibit A and subject to the terms set forth herein in addition to any applicable terms set forth in the Members' Partial Requirements Capacity and Energy Agreement.

Billing Month – The first calendar month preceding the month the bill is rendered.

Demand Overrun Adjustment – If, in any hour, (i) Member's scheduled load (if Member is not in AEPCO's Control Area) or (ii) Member's metered load less capacity obtained from sources outside the Dispatch Pool (if Member is in AEPCO's Control Area) exceeds its Allocated Capacity, then Member shall be charged a Demand Overrun Adjustment. Such Demand Overrun Adjustment shall equal the product of Member's Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((mbdkW) / AC) - 1$$

Where:

doaf	=	Demand Overrun Adjustment Factor,
mbdkW	=	Member Schedule in kW or Metered kW less capacity from sources outside the Dispatch Pool, as applicable, and
AC	=	Allocated Capacity of Member, in kW.

In addition, Member shall pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Resources Energy Rate.

Power Factor – Each Member shall maintain Power Factor at the time of maximum demand as close to unity as possible. If the Power Factor of Member measured at the aggregated Member's Delivery Point(s) at the time of Member's peak demand is outside a bandwidth of 95% leading to 95% lagging, a Power Factor Adjustment shall be separately charged to the Member. The Power Factor Adjustment shall be the product of the Member's power factor adjustment (as set forth below) multiplied by the quotient of the Member's O&M Charge divided by the sum of the Member's 12-month rolling average demand. The power factor adjustment kW shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW = power factor adjustment in kW,
mkW = Member Metered kW,
mpf = measured power factor at the time of Member peak demand, and
bpf = 0.95.

The provisions of the power factor adjustment may be waived if power factor is detrimentally impacted as a direct result of system improvements or a change in operational procedure by AEPCO to reduce transmission losses and/or improve system reliability.

Taxes – Bills rendered are subject to adjustment for all federal, state and local government taxes or levies, including any taxes or levies imposed as a carbon tax or "cap and trade" or other carbon assessments system imposed on electricity sales or electricity production and any assessments that are or may be imposed by federal or state regulatory agencies on electric utility gross revenues.

Power Cost Adjustor Rates

"Base Resources" are defined as (1) AEPCO's Steam Turbine Units 2 and 3, (2) power purchased under contract from the Western Area Power Administration and (3) economy purchases displacing base resources generation.

"Other Resources" are defined as (1) AEPCO's generation units other than Steam Turbine Units 2 and 3, (2) power purchased under contracts which serve the combined scheduled loads of AEPCO's Class A members plus power purchased under contract and economy energy purchases (other than economy purchases displacing base resources generation) made for the purpose of meeting the scheduled load requirements of all Class A members and (3) power purchased under contracts or resources which have been acquired to serve Class A Member load and which the Member has expressly agreed to in a participation agreement.

The monthly bill computed under this Tariff shall, using the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh derived from each resource type by the applicable Power Cost Adjustor Rate for Base Resources and Other Resources where:

Base Resources Adjustor Rate

BF = (BPC + BBA) - BFB

BF = Base Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BPC = The Commission-allowed pro forma fuel costs of Base Resources generation, purchased power costs of Base Resources and wheeling costs associated with Base Resources in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BBA = The "Base Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Base Resources. The BBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Base Resources kWh energy sales.

BFB = The Base Resources Fuel Base or BFB is $0.03330 for MEC, $0.03337 for SSVEC and $0.03336 for Trico.

Allowable Base Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 2 and 3 as recorded in RUS Account 501, plus

B. The actual costs associated with Base Resources power purchased for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis to substitute for higher cost Base Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Base Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the all-requirements Class A members, less

E. The demand and energy costs recovered through non-tariff contractual firm sales of Base Resources power and energy as recorded in RUS Account 447, and less

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Base Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

<u>Other Resources Adjustor Rate</u>

OF = (OPC + OBA) - OFB

OF = Other Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

OPC = The Commission-allowed pro forma fuel costs of Other Resources generation, Other Resources purchased power and wheeling costs associated with Other Resources in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

OBA = The "Other Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Other Resources. The OBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Other Resources energy sales.

OFB = The Other Resources Fuel Base or OFB is equal to $0.06971 for MEC, $0.07241 for SSVEC and $0.09084 for Trico.

Allowable Other Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 1, 4, 5 and 6 as recorded in RUS Accounts 501 and 547, plus

B. The actual costs associated with Other Resources purchased power for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of Other Resources energy purchased when such energy is purchased on an economic dispatch basis. Included therein are such costs as those charged for economy energy purchases and the charges as a result of a scheduled outage of Other Resources generation units. All such kinds of Other Resources energy being purchased by AEPCO to substitute for its own higher cost Other Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Other Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the all-requirements Class A members, less

E. The demand and energy costs recovered through non-tariff contractual firm sales of Other Resources power and energy as recorded in RUS Account 447, and less

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Other Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Power Cost Adjustor Rates as specified herein based upon a rolling 12-month average of allowable fuel, purchased power and wheeling costs (BPC and OPC) plus a bank balance amortization component (BBA and OBA). AEPCO shall initially file by September 1, 2011 and thereafter on March 1 or September 1 of the month preceding the effective date of the revised Power Cost Adjustor Rates (i.e., April 1 or October 1): (1) calculations supporting the revised Adjustor Rates with the Director, Utilities Division, and (2) a Tariff reflecting the revised Adjustor Rates with the Commission which shall be effective for billings after the first day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

EXHIBIT A

Effective Date	January 1, 2011*		
Partial Requirements Members:	MEC	SSVEC	Trico
Fixed Charge – $/month	$727,283	$643,991	$646,435
O&M Charge – $/month	$1,274,882	$1,128,876	$764,465
Base Resources Energy Rate – $/kWh	$0.03215	$0.03229	$0.03238
Other Resources Energy Rate – $/kWh	$0.06879	$0.06676	$0.06604

MEC

Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

SSVEC

Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

Trico

Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

* Rates are effective for service provided on and after this date.
** Effective January 1, 2011 and determined as set forth in the Tariff.