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**BEFORE THE ARIZONA CORPORATION COMMISSION**

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CHAIRMAN
JIM IRVIN
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WILLIAM A. MUNDELL
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| IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR VARIOUS AUTHORIZATIONS ASSOCIATED WITH ITS RESTRUCTURING | No.: E-01773-A-00-0826<br><br>**APPLICATION** |

The Arizona Electric Power Cooperative, Inc. ("AEPCO"), by and through its attorneys undersigned, submits this application for various approvals necessary to accomplish its restructuring. As part of the restructuring, AEPCO also seeks Commission approval of an overall 3.05% rate decrease for its members as well as permission to forgive an undercollection in its Purchased Power and Fuel Adjustment Clause (PPFAC) bank currently estimated to be $3 million as of December 31, 2000. AEPCO is an Arizona non-profit, generation and transmission cooperative which holds, pursuant to Decision No. 33677 dated February 13, 1962, a Certificate of Convenience and Necessity ("CC&N") to generate electricity and transmit that power and energy to its member distribution cooperatives at wholesale.

AEPCO's Arizona Class A member distribution cooperatives are Duncan Valley Electric Cooperative, Inc., Graham County Electric Cooperative, Inc., Mohave Electric Cooperative, Inc., Sulphur Springs Valley Electric Cooperative, Inc. and Trico Electric Cooperative, Inc. (collectively, the "Member Distribution Cooperatives"). The Member Distribution Cooperatives take the power and energy supplied by AEPCO at wholesale through their all requirements agreements and deliver it to meet the needs of their members at retail. This AEPCO system supplies electricity to roughly 250,000 rural Arizonans living in areas ranging from Greenlee,

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Graham and Cochise counties in the southeast part of the state through southern Arizona to Mohave county in the northwest.

The Rural Utilities Service ("RUS"), an agency of the U.S. Department of Agriculture, is AEPCO's primary lender or guarantor for the funds necessary to construct the generation and transmission facilities to deliver this power throughout much of rural Arizona. RUS also finances a substantial portion of the distribution facilities which are operated by the Member Distribution Cooperatives at retail. To secure the loans it makes to AEPCO, the RUS relies on two primary forms of security: (1) a mortgage on all of AEPCO's assets and (2) a security interest in the all requirements agreements executed by the Member Distribution Cooperatives under which AEPCO commits to generate and deliver and the members agree to purchase all of the energy they need to supply at retail (thus providing a revenue stream for debt repayment to RUS). These all requirements agreements currently extend to December 31, 2020. Although RUS is AEPCO's primary lender and guarantor, AEPCO also borrows money from other sources - principally the National Rural Utilities Cooperative Finance Corporation ("CFC"). CFC and other lenders and bondholders/trustees also hold encumbrances on AEPCO's assets. All lenders' consent is necessary for AEPCO's restructuring.

## I. SHORT STATEMENT OF THE APPLICATION.

Following more than four years of analysis, negotiation and document formulation, including extensive consultation with RUS, AEPCO and its Member Distribution Cooperatives have completed the planning for and form of the restructuring of AEPCO. Essentially, the AEPCO restructuring involves the functional separation of the existing AEPCO into three, separate member-owned non-profit cooperatives--two new and one old. The two new cooperatives (which have already been formed) are Sierra Southwest Cooperative Services, Inc.

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("Sierra") and Southwest Transmission Cooperative, Inc. ("Southwest Transmission"). AEPCO continues in existence to provide the wholesale generation of power while several of its former functions are being transferred to Southwest Transmission and Sierra.

In order to accomplish the restructuring, AEPCO seeks the Commission's approval, pursuant to A.R.S. § 40-285, to transfer its regulatory assets and the transmission-related assets including the transmission portion of its CC&N to Southwest Transmission (the "Transmission Assets") as well as to transfer certain other relatively minor assets (the "CSP business") to Sierra. No new borrowing is involved in order to accomplish the restructuring. Sierra will pay cash for the CSP business. Southwest Transmission will pay for the transmission assets at their appraised, fair market value by assuming and securing a portion of existing AEPCO RUS and CFC debt through entering into replacement notes secured by a new mortgage and by entering into assumption and indemnity agreements with existing AEPCO lenders other than RUS and CFC. AEPCO may also execute replacement notes on the portion of debt attributable to its generating and other facilities not transferred to Southwest Transmission. Commission approval, pursuant to A.R.S. § 40-301 et. seq., of these AEPCO and Southwest Transmission notes, mortgages and assumption and indemnity agreements is sought.

The restructuring also involves the approval of a new Partial Requirements Capacity and Energy Agreement ("Partial Requirements Agreement") with Mohave Electric Cooperative, Inc. ("Mohave"). With the consent of the RUS, Mohave has elected as part of the AEPCO restructuring to change its relationship to a partial instead of an all requirements member. As a result of this change, AEPCO seeks Commission approval of the new Partial Requirements Agreement with Mohave and certain changes to its existing Class A member wholesale tariff. The rates proposed for all Member Distribution Cooperatives in the Partial Requirements

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Agreement and the revised tariff represent an average 3.05% decrease in rates based on a 1999 test year. Finally, AEPCO also seeks certain other miscellaneous approvals associated with the restructuring.

It is the parties' intention to close the AEPCO restructuring by January 31, 2001. Therefore, AEPCO requests that the Commission act favorably on this Application at its December Open Meeting so as to allow sufficient time for the parties to finalize documentation, arrange a myriad of details and logistics associated with the closing and meet the intended closing date.

## II. BACKGROUND OF THE RESTRUCTURING.

Attached to this Application as Exhibit A is the Restructuring Agreement and its Schedules 1 through 3 by and among AEPCO, Southwest Transmission and Sierra. Its Section 2 provides an excellent overview of the details associated with the restructuring. The Restructuring Agreement was presented to and approved by the Boards of Directors of the three cooperatives on October 10 and 11, 2000.

The approval of the Restructuring Agreement culminates a grass roots study and implementation process which began in earnest in 1996 with the formation of the AEPCO Structure/Wholesale Power Contract Study Committee. The Study Committee was comprised and chaired by representatives of the Member Distribution Cooperatives. Over the next more than 15 months, it analyzed and debated various reorganization issues and concepts. Videos of Study Committee discussions were made available to members throughout the AEPCO system and were accompanied by several system-wide presentations concerning its monthly progress.

Ultimately, the Study Committee settled upon the basic outline of the reorganization, as reflected in the Restructuring Agreement, and issued its report to the AEPCO Board. These

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Conceptual Recommendations were presented to a membership information meeting attended by the directors of AEPCO's Member Distribution Cooperatives and their retail members in September of 1997. They were then accepted and approved by AEPCO's Board.

In approaching restructuring, AEPCO's Board, its Class A members and their retail members recognized that greater flexibility was required for AEPCO and its Member Distribution Cooperatives as they prepare for the opportunities and challenges of competition in the 21st century. But, the Study Committee also wanted to preserve certain concepts and assets which had served the cooperatives well for much of the 20th century. The restructuring approach formulated by the Study Committee identified several basic reasons why its chosen form of restructuring afforded both the desired degree of flexibility and stability. Among them are:

- Increased competitiveness. The separation of AEPCO into three cooperatives allows each entity to focus on more specific areas of responsibility and maximize the utilization and productivity of each entity's assets and workforce. Sierra is also available to assist the Member Distribution Cooperatives in their competitive efforts and to provide competitive options and technology in rural areas--a market expected to be unserved or underserved by competitive providers.

- Focused generation and transmission resource financing. The restructuring allows the cooperative system to retain valuable assets, but to augment, improve and maintain those assets based on separately identified generation and transmission goals.

- Create additional organizational, operational, financial and marketing efficiencies. Although each of the three cooperatives will have certain staff dedicated and employed by that entity, Sierra's role as a general staffing organization allows the Cooperatives to focus efforts without unnecessary and expensive duplication of other personnel.

- Make available more flexible power purchase arrangements to the Member Distribution Cooperatives. Most of AEPCO's Class A Members wanted to continue the historic all-requirements arrangement, but Mohave desired a different approach. The restructuring and Partial Requirements Agreement accommodates both desires.

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- Full compliance with regulatory requirements. The separation of generation, transmission and competitive service functions into three cooperatives facilitates compliance by each with federal and state regulatory mandates including FERC Open Access and OASIS Orders and this Commission's Electric Competition Rules.

Following Board approval of the Conceptual Recommendations in late 1997, a Member Review Team comprised of counsel and consultants from the Member Distribution Cooperatives was formed. This team has been responsible for creating specific documents and negotiating precise details of the restructuring. AEPCO and the team have also conducted extensive discussions and negotiations with RUS.

Last month, RUS gave its conceptual approval to the restructuring and approval to proceed with the filing of this Application. It also agreed to the specific provisions of the Restructuring Agreement.

## III. NATURE OF THE RESTRUCTURING.

AEPCO's restructuring functionally separates AEPCO into three distinct cooperatives:

- AEPCO retains ownership of the generation business including the 520 MW of resources at Apache Station and its purchased power contracts. AEPCO will focus on its traditional generation functions including Apache Station operation, existing wholesale power purchases and sales, wholesale merchant marketing, resource pool operation and planning for and meeting the power needs of its all requirements Member Distribution Cooperatives.

- Southwest Transmission will acquire the Transmission Assets from AEPCO. It will operate and maintain the transmission business and perform SCADA, system reliability and control, dispatch and related transmission functions including construction and operation of necessary future additions to the system.

- Sierra will perform two functions, the first of which includes power marketing, retail electric service marketing and sales and retail sales of other products. Sierra will also act as a staffing organization for AEPCO and Southwest Transmission. Most of the current AEPCO employees will be transferred to Sierra and their services will then be contracted back to AEPCO and Southwest Transmission. Both cooperatives will retain, however, certain upper level management and dedicated personnel to perform generation-related merchant marketing and resource pool functions for AEPCO and transmission related system operation

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functions for Southwest Transmission.

Each cooperative's Board is comprised of representatives of its members. AEPCO will continue to be governed as it is today. Southwest Transmission has two classes of membership for Board representation--the Class A Member Distribution Cooperatives and a Class B designation for AEPCO, Sierra and other wholesale contract customers of Southwest Transmission. Sierra has three member classes: (1) Class A Member Distribution Cooperatives, (2) a Class B member category comprised of AEPCO and Southwest Transmission and (3) a Class C membership for customers buying Sierra's energy or energy related services at retail.

The restructuring also involves a new partial requirements power supply arrangement with Mohave. Under this agreement, Mohave commits to purchase a fixed amount of capacity and energy from AEPCO based upon historic investment and demand, but then may secure from any source its additional power requirements. AEPCO's other Member Distribution Cooperatives will continue to acquire power from AEPCO under their existing all requirements agreements.

Mohave will enter into a Transmission Agreement with Southwest Transmission for delivery of its energy from AEPCO and AEPCO will enter into a Network Service Agreement with Southwest Transmission for delivery of AEPCO's energy to the other all requirements Class A members. Both the Transmission Agreement and the Network Service Agreement will be submitted for filing with the Federal Energy Regulatory Commission (FERC) along with Southwest Transmission's Open Access Transmission Tariff (OATT), OATT rates (wholesale open access transmission rates), OASIS Standards of Conduct and other wholesale OATT agreements in conformance with FERC Orders No. 888 and 889. Southwest Transmission will seek a "safe harbor" determination from FERC that it meets reciprocity standards to receive open

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access transmission service from others.

## IV. SPECIFIC APPROVALS REQUESTED.

### A. Transfer Of Assets.

The division of the functions is accomplished through the sale and transfer by AEPCO of the Transmission Assets to Southwest Transmission and the CSP business to Sierra. More precise details concerning these transfers are set forth in Section 2 and Schedules 1-3 of the Restructuring Agreement.

The Transmission Assets include the transmission, substation, communications and other non-generation related assets identified on Schedule 1 to the Restructuring Agreement. The Transmission Assets will be transferred at their fair market value to Southwest Transmission together with the regulatory assets of AEPCO as already authorized by the Commission in Decision No. 62758. Southwest Transmission will pay for the Transmission Assets generally by assuming a portion of existing AEPCO debt. The purchase price of the transmission assets is established by an independent appraisal. The CSP business consists of relatively minor assets as identified on Schedule 2 to the Restructuring Agreement. Sierra will pay cash for these assets.

Pursuant to A.R.S. § 40-285, AEPCO requests Commission approval to transfer the Transmission Assets to Southwest Transmission and the CSP business to Sierra.

### B. Financing Approvals.

No new borrowing is involved in the restructuring and replacement notes will be on the same interest terms and conditions as the existing debt. Primarily based upon the appraisal of the Transmission Assets and the assignment of the regulatory assets, existing debt will be allocated between AEPCO and Southwest Transmission which will enter into replacement notes with the RUS and CFC, secured by a mortgage, and four assumption and indemnity agreements.

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Schedule 3 to the Restructuring Agreement provides additional information concerning the allocation of debt.

Southwest Transmission will execute notes and a mortgage evidencing the borrowings and securing them. AEPCO may execute replacement notes for the balance. Southwest Transmission will also execute assumption and indemnity agreements pertaining to debt issued by existing AEPCO lenders other than RUS and CFC. This debt cannot be released and novated in the same fashion as the RUS and CFC debt.

Pursuant to A.R.S. § 40-301 et seq., AEPCO requests Commission approval for the execution by it and Southwest Transmission of these notes, mortgages and assumption and indemnity agreements.

**C. Partial Requirements Capacity And Energy Agreement/Revised Class A Member Tariff Approval.**

Attached hereto as Exhibit B is the Partial Requirements Agreement including its Rate Schedule A and the non-table portions of Schedule B between AEPCO and Mohave. It is a new agreement which, when finalized, will control the sale and purchase of power and energy between AEPCO and Mohave after restructuring. Also attached as Exhibit C is a revised all requirements Class A member AEPCO tariff. Because of the change in relationship between AEPCO and Mohave as well as the re-basing of the rates premised on a 1999 test year, certain applicability and rate modifications also are necessary to the existing tariff concerning sales to the rest of the Member Distribution Cooperatives.

Rates have been designed in accordance with the concepts and provisions of Rate Schedule A to the Partial Requirements Agreement. They are based upon costs incurred in the 1999 calendar test year. The rates proposed in Exhibits B and C, including transmission rates to be charged by Southwest Transmission, will produce on average 3.05% less revenues than

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produced under current rates. The proposed rates produce an 8.44% rate of return on AEPCO's generation related assets at original cost (which it agrees can be used as its fair value) and afford a debt service coverage ratio of 1.0, the minimum required by RUS to avoid mortgage default.

In addition, as part of this Application, AEPCO also seeks Commission approval to forgive the undercollection in its PPFAC bank as of the effective date of the restructuring and to eliminate from its tariff its PPFAC on an on-going basis. It is projected that, as of December 31, 2000, this PPFAC undercollected balance will amount to approximately $3 million. Based on 1999 test year revenues, this $3 million forgiveness amounts to an additional 3.6% one time decrease.

Pursuant to A.R.S. § 40-367, Commission approval of the Partial Requirements Agreement and the revised Class A all requirements member tariff attached as Exhibit C is requested.

**D. <u>Other Approvals</u>.**

AEPCO is not certain that the provisions of A.A.C. R14-2-1615 apply to it because it does not have "competitive generation assets" as that term is used in the Rule. AEPCO does believe, however, that the restructuring described in this Application meets and, in fact, exceeds the Rule's requirements and requests Commission confirmation of that compliance.

On February 4, 2000, AEPCO and its Member Distribution Cooperatives filed a request for waivers and a Code of Conduct pursuant to R14-2-1616 in relation to each of them and Sierra. A copy of this filing is attached hereto and incorporated herein as Exhibit D. Because waiver of the provisions of the Rule or approval of the Code of Conduct is required to effectuate a number of agreements which achieve the purposes of the restructuring, Commission approval of the requested waivers or the Code of Conduct pursuant to R14-2-1616 is requested.

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Finally, the Commission has previously granted a CC&N to Sierra in Decision No. 61932 subject to confirmation of credit arrangements and the extent of the financial commitment from AEPCO. As indicated in the Restructuring Agreement, AEPCO and Southwest Transmission will make capital contributions to Sierra of $4 million upon closing of the restructuring. Sierra has also applied for credit support in the amount of $3 million from CFC in connection with its needs. Therefore, confirmation by the Commission that the requirements of Decision No. 61932 have been satisfied is requested.

## CONCLUSION

The AEPCO restructuring is in the public interest for a variety of reasons. It delivers immediate rate reductions and benefits to rural Arizona; facilitates compliance with this Commission's and FERC's regulatory mandates; enhances competitive options; better focuses generation and transmission resource financing and operation; and affords both flexibility and stability for future power purchase arrangements for members.

In light of the foregoing, AEPCO respectfully requests that the Commission enter its Order:

1. Approving the transfer of its Transmission Assets to Southwest Transmission and its CSP business to Sierra;
2. Approving the execution by it and Southwest Transmission of the notes, mortgages and assumption and indemnity agreements associated with the restructuring;
3. Approving the Partial Requirements relationship between AEPCO and Mohave with the final executed agreement to be filed with the Commission upon completion of the restructuring;

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4. Approving the revised Class A member all requirements tariff attached as Exhibit C and authorizing AEPCO to forgive its PPFAC undercollection as of the effective date of the restructuring;

5. Confirming that by its restructuring AEPCO has complied with the requirements of R14-2-1615;

6. Approving the waivers or alternatively the Code of Conduct as described in Exhibit D;

7. Confirming that the financial commitment conditions of Decision No. 61932 pertaining to Sierra have been satisfied; and

8. Authorizing AEPCO, Southwest Transmission and Sierra to engage in any transactions and to execute any documents necessary to effectuate these authorizations and complete the restructuring.

In order that the restructuring may close and the rate reductions may take effect as promptly as possible, AEPCO requests the Commission enter this Order at its December Open Meeting.

DATED this 17th day of October, 2000.

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DOCKET NO. E-01773A-00-0826

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| IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR VARIOUS AUTHORIZATIONS ASSOCIATED WITH ITS RESTRUCTURING | No.: E-01773-A-____ |

# EXHIBITS IN SUPPORT OF THE APPLICATION OF AEPCO FOR VARIOUS APPROVALS ASSOCIATED WITH ITS RESTRUCTURING

# A

# RESTRUCTURING AGREEMENT

BY AND AMONG

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

AND

SIERRA SOUTHWEST COOPERATIVE SERVICES, INC.

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### Exhibits


| | |
|---|---|
| Exhibit A | Assumption and Indemnity Agreements between AEPCO, TRANSCO and _____ |
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| Exhibit C | Staffing Agreement between CSP and TRANSCO |
| Exhibit D | Joint Marketing Agreement |


### Appendices


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| Appendix A | Definitions |

# RESTRUCTURING AGREEMENT

## PARTIES

The Parties to this RESTRUCTURING AGREEMENT (Agreement) dated as of _____, 2000, are Arizona Electric Power Cooperative, Inc. (AEPCO), Southwest Transmission Cooperative, Inc. (TRANSCO), and Sierra Southwest Cooperative Services, Inc. (CSP), each of which is a non-profit corporation organized under the generation and transmission electric cooperative laws of the State of Arizona. AEPCO, TRANSCO and CSP are referred to individually as "Party" and collectively as "Parties" herein.

## RECITALS

This Agreement is made with reference to the following facts, among others:

A. The Parties believe that, under current and foreseeable industry conditions, the continued ability of the Class A Members to operate as effective retail electric cooperatives requires increased flexibility in meeting their future needs for electric capacity and energy than are currently available under the existing organization of AEPCO.

B. The Parties have determined that it is in their mutual best interests to restructure AEPCO to provide for greater future flexibility and for the purpose of adjusting to changes in the electric industry.

C. The purpose of this Agreement, executed and dated October ____, 2000, and the Member Agreement, to be executed, dated and made effective as of the Effective Date, and to be entered into by the Parties and each of the Class A Members of AEPCO is to collectively evidence their agreement, as set forth herein and therein, to establish the terms and conditions on which the restructuring will occur, including the separation of AEPCO's "Transmission Business," substantially as an entirety, and its "CSP Business," substantially as an entirety, from AEPCO's "Generation Business" (as such terms are further defined in Appendix A) and to establish certain new contractual relationships among and between the parties to the Restructuring Agreement and the parties to the Member Agreement. Mohave Electric Cooperative, Inc. is referred to herein as the "Partial Requirements Member" or "MEC." AEPCO will sell and transfer the Transmission Business, including the Non-Generation Assets, which include capacity rights, ancillary services and other such rights to TRANSCO. The CSP Business will be transferred by AEPCO to CSP. AEPCO will continue to conduct the Generation Business.

D. The Parties further intend to establish CSP as a viable market participant in the current and restructured electric industry.

## AGREEMENT

NOW, THEREFORE, in consideration of the premises and the mutual undertakings contained herein, and intending to be legally bound hereby, the Parties agree as follows:

1. DEFINITIONS:

All capitalized terms used and not defined herein shall have the respective meanings as set forth in Appendix A to this Agreement.

1.1 "AEPCO Mortgage" shall mean the Consolidated Mortgage and Security Agreement, dated as of June 14, 1989, by and among AEPCO, as mortgagor, and the Government acting through the Administrator of the RUS, and CFC, as mortgagees, as amended and consolidated, or restated from time to time, which secures the obligations thereunder and creates a lien on substantially all of the real and tangible personal property of AEPCO in favor of such mortgagees, additional substitute mortgagees and other secured parties.

1.2 "Close of Books Date" shall mean the date when AEPCO's actual financial statements and records as of the Closing Date are available in final form.

1.3 "Closing Purchase Price" shall mean such price for the Transmission Business as specified in Section 2.4(d) herein.

1.4 "Collective Bargaining Agreement" shall mean the agreement between AEPCO and the IBEW, dated March 1, 1999, or any successor agreement.

1.5 "Employee Benefit Plan(s)" shall mean the plans set forth in Section 2.11(c) of the Restructuring Agreement.

1.6 "Final Appraisal" shall mean the final appraisal of the Non-Generation Assets as of the Closing Date as determined by an independent appraiser selected by AEPCO, as further set forth in Section 2.4(c) herein.

1.7 "Internal Revenue Service" shall mean the Internal Revenue Service, an agency of the Treasury Department of the United States of America or any successor agency of the Government.

1.8 "IRS Ruling" shall mean any ruling, determination, advice memorandum, or private letter from the Internal Revenue Service applied for and received by AEPCO and TRANSCO with respect to the status of each for federal income tax purposes pursuant to Section 3.1(a) herein.

1.9 "Loan Contract" shall mean the separate agreement entered into by and between AEPCO and the United States of America, acting by and through the Administrator, and the separate agreement entered into by and between TRANSCO and the United States of America, acting by and through the Administrator, governing the terms, conditions and repayment of loans to finance, pursuant to the Act, the construction and operation of the AEPCO and TRANSCO systems, for the purpose of furnishing or transmitting electric energy to persons in rural areas, as evidenced by outstanding notes payable to the Government; outstanding notes payable to FFB, and the

Government, acting by and through the Administrator, who has guaranteed the repayment of such funds; and reimbursement obligations evidenced by outstanding notes payable to the Government in respect of such reimbursement obligations.

1.10 "Net Book Value" of any asset shall mean at any given time the amount at which such asset is recorded on the books of the owner of such asset, less accumulated depreciation as computed consistent with Accounting Requirements.

1.11 "Non-Generation Liabilities" shall mean, as determined in accordance with Accounting Requirements, that portion of AEPCO's Indebtedness assumed pursuant to Section 2.4(b) herein and as further set forth in Schedule 1 attached hereto (excluding open accounts payable that exist as of the Effective Date). The Non-Generation Liabilities shall also include any and all costs, expenses, obligations and liabilities incurred in connection with or otherwise relating to any litigation described in Schedule 1 relating to Non-Generation Assets, and not paid prior to the Effective Date.

1.12 "Preliminary Appraisal" shall mean the initial and preliminary appraisal of the Non-Generation Assets dated June 30, 2000, as determined, in accordance with Accounting Requirements, by an independent appraiser selected by AEPCO as set forth in Section 2.4(c) herein.

1.13 "Purchase Price Adjustment" shall mean, in each case, in accordance with Accounting Requirements: (A) that amount, if any, by which: (i) the consideration received by TRANSCO for any sale, lease or exchange of all of the Transmission Business constituting a Purchase Price Adjustment Event exceeds the Closing Purchase Price, or (ii) the value of the Transmission Business reflected in the consideration received by TRANSCO or the TRANSCO Members in any merger or consolidation of TRANSCO or any other full disposition or reduction of the TRANSCO Members' capital interests constituting a Purchase Price Adjustment Event exceeds the Closing Purchase Price, in each of the types of transactions set forth in (i) and (ii) herein, net of taxes and other expenses attributable to the transaction, minus (B) any Purchase Price Adjustment previously paid with respect to such Transmission Business.

1.14 "Purchase Price Adjustment Event" shall mean the consummation by TRANSCO or the TRANSCO Members of any one or more transactions after the Closing Date and prior to the fifth anniversary of the Effective Date (or thereafter if consummated pursuant to a binding contract entered into after the Closing Date and prior to the fifth anniversary of the Effective Date) pursuant to which TRANSCO sells, leases or exchanges one hundred percent in the aggregate (measured and determined based on Net Book Value at the time of the transaction or during the time of any series of related transactions) of the Transmission Business, or merges or consolidates with another entity.

1.15 "TRANSCO M and E Allocation" shall mean the amounts of AEPCO margins and equities incurred prior to the Closing Date which shall be allocated and assigned to TRANSCO pursuant to Sections 2.3(a) and 2.3(c) herein, in accordance with the allocation methodology set forth in Schedule 3 attached hereto.

2. THE RESTRUCTURING:

2.1 The Restructuring and Division of Functions. On the terms and conditions set forth herein, the Transmission Business and the CSP Business shall be separated from AEPCO's other

business functions, assets and liabilities, primarily including those business functions relating to the generation, purchase or sale of power. AEPCO shall retain its Generation Business, consisting of, among other things, operation and maintenance of Generating Resources, power and economy purchase and sale agreements (set forth on Schedule 4 to this Agreement), and including, but not limited to, Economy Sales and Economy Purchases, operation of the Resource Pool and assets and liabilities related to the Generation Business.

(a) CSP Business

(i) As soon as all required approvals and consents have been obtained and the conditions contained in Section 7.1(d) and (e) hereof, to the extent they relate to the transfer of the CSP Business, have been satisfied or waived, and without waiting for the closing of the other transactions contemplated hereby, the CSP Business, including the CSP Assets, shall be transferred by AEPCO to, and assumed by CSP. AEPCO shall sell and transfer and CSP shall purchase and assume, the CSP Business, including the CSP Assets, and also all of the capital stock of TSEPP, free of the lien of RUS and CFC under the AEPCO Mortgage as provided by Section 2.6 hereof on or before the Closing Date.

(ii) On or before the Closing Date, AEPCO shall terminate the employment of all AEPCO Employees other than AEPCO Retained Personnel, whereupon TRANSCO shall immediately make an offer of employment to the TRANSCO Employees, pursuant to the provisions of Section 2.8 hereof. CSP shall also immediately make an offer of employment to the remaining AEPCO Employees, except for the AEPCO Retained Personnel and the TRANSCO Employees, pursuant to the provisions of Section 2.8 hereof. On the Effective Date CSP shall begin providing Personnel, pursuant to the Staffing Agreements, as provided by Section 2.9 of this Agreement.

(iii) No later than the Effective Date, CSP shall begin providing services to AEPCO and the Class A Members, including the marketing of surplus energy resources, the assembly of new resources, and the provision of staffing solutions. CSP shall assume ownership and operational responsibility for TSEPP. CSP shall also undertake the retail sales of products other than retail electric service as determined by the Board of Directors of CSP.

(b) AEPCO Closing Date Allocation and Attribution. At the Closing, AEPCO shall fully effect and implement the AEPCO Closing Date Allocation and Attribution as more fully set forth in Section 2.3 hereof.

(c) Transmission Business. Prior to the Closing Date, AEPCO and CSP shall complete the actions acceptable to TRANSCO necessary to become a TRANSCO Member. At the Closing, AEPCO shall sell and transfer, and TRANSCO shall purchase and assume, the Transmission Business, including the Non-Generation Assets, pursuant to the provisions of Section 2.4 hereof. TRANSCO shall on the Effective Date begin providing transmission services and Ancillary Services pursuant to the Transmission Agreement, Network Service Agreement, Service Agreements for Firm and Non-Firm Transmission and Ancillary

Services, and similar agreements, as set forth in Section 2.5 hereof, subject to receiving all required consents and approvals.

2.2 Partial Requirements Capacity and Energy Agreement. To facilitate the restructuring of AEPCO, including the transfer of the Transmission Business to TRANSCO, AEPCO shall execute and deliver, at or before Closing, a new Partial Requirements Capacity and Energy Agreement with the Partial Requirements Member pursuant to the terms of the Member Agreement. The Existing Wholesale Power Contracts among AEPCO and the All Requirements Members shall continue in effect after the Effective Date. Commencing as of the Effective Date, provided the approval of each of the ACC, Financial Entities, RUS, and FERC, if required, has been obtained, the Partial Requirements Capacity and Energy Agreement shall govern the purchase and sale of capacity and energy between AEPCO and the Partial Requirements Member.

2.3 AEPCO Closing Date Allocation and Attribution. As of the Closing Date, AEPCO shall make applicable proportionate allocations and attributions of patronage capital, margins and equities (based on the June 30, 2000 results reported on RUS's Form 12a (Section B Balance Sheet) as submitted by AEPCO to RUS, which allocations shall be adjusted to reflect actual amounts as of the Closing Date when final Closing Date results are available as to the allocation provided for in Section 2.3(c) herein) in amounts either as prescribed in Schedule 3 of this Agreement, or in amounts determined on the basis of the methodology set forth in such Schedule 3 (the "AEPCO Closing Date Allocation and Attribution"), as follows:

(a) Allocation of Patronage Capital Assigned and Assignable to AEPCO and TRANSCO. An allocation and assignment shall be made as of the Closing Date first among the assigned and assignable margin and equity accounts of AEPCO, (in effect after the Closing Date), and TRANSCO on the basis of the methodology set forth in Schedule 3 of this Agreement.

(b) Allocation of Patronage Capital Assigned and Assignable among Class A Members. An allocation and assignment shall then be made among the AEPCO and TRANSCO Class A Member patron's accounts of patronage capital assigned on April 15, 1974 by AEPCO, as of the Closing Date, on the same basis as the patronage capital was originally allocated and assigned on April 15, 1974 to the Class A Members' AEPCO patron accounts as determined prior to the Closing Date such that the sum of each Class A Member's AEPCO patronage allocation plus TRANSCO patronage allocation, as of the Closing Date, is equal in total to the amounts allocated and assigned on April 15, 1974 to such AEPCO Class A Member as determined prior to the Closing Date.

(c) Allocation of Total Margins and Equities (Net of Patronage Capital Assigned, Assignable, or Retired) between AEPCO and TRANSCO. An allocation and assignment of AEPCO balance sheet equity and margins incurred prior to the Closing Date, shall be made between AEPCO and TRANSCO as of the Closing Date on the basis of the methodology set forth in Section 2.4(d)(ii) hereof and Schedule 3 to this Agreement.

2.4 Acquisition of Transmission Business. At the Closing, the Transmission Business shall be sold and transferred by AEPCO to TRANSCO. The Parties shall cooperate with one another in taking such actions and making such adjustments as shall be appropriate to cause the economic

consequences of such actions and changes to fulfill the purposes of this Agreement, as of the Closing Date. The Parties acknowledge and agree that the identity of the Non-Generation Assets, and the Non-Generation Liabilities, will be based on AEPCO's projected financial statements and records as of the Closing Date, and shall be adjusted as of the Closing Date when AEPCO's actual financial statements and records as of the Closing Date are available in final form (the "Close of Books Date"), and shall be as set forth in amendments to Schedule 1 to this Agreement.

(a) Purchase and Sale of Transmission Business. At the Closing, effective as of the Closing Date, AEPCO shall sell, convey, transfer, assign and deliver to TRANSCO, and TRANSCO will receive, accept and pay for all of the Transmission Business, pursuant to the pricing and payments provisions of Sections 2.4(d) and (e) hereof. At the Closing, AEPCO shall deliver to TRANSCO special warranty deeds, dated the Closing Date, conveying to TRANSCO all of AEPCO's right, title and interest in and to the real property included in the Non-Generation Assets, subject to the reservation by AEPCO of nonexclusive easements, rights-of-way and possessory interests to use such property in any way that does not unreasonably interfere with TRANSCO's use of such property to conduct the Transmission Business, and bills of sale, endorsements, assignments and other good and sufficient instruments of conveyance and transfer of interest as shall be effective to vest in TRANSCO all of AEPCO's right, title and interest in and to all other Non-Generation Assets, including the interest of AEPCO in the Transmission Business Agreements set forth in Schedule 5 to this Agreement. At the Closing, AEPCO and TRANSCO will each take such other steps as may be reasonably required to put TRANSCO in actual possession and operating control of the Transmission Business, including the Non-Generation Assets and other assets included in the Transmission Business. From time to time after the Closing, at TRANSCO's request and expense but without further consideration, AEPCO will execute and deliver such other instruments of conveyance and transfer and take such other actions as TRANSCO reasonably may require to vest more effectively in TRANSCO, and to put TRANSCO in possession of, the Non-Generation Assets subject to the above mentioned easements, rights-of-way and possessory interests reserved by AEPCO. AEPCO shall obtain a release of lien of the AEPCO Mortgage from the RUS and CFC with respect to the Transmission Business, including the Non-Generation Assets, upon the recordation and creation of the TRANSCO Mortgage.

(b) Assumption of Non-Generation Liabilities. At the Closing, effective as of the Effective Date, TRANSCO shall execute and deliver to AEPCO and to such other persons and entities as may be appropriate all such assumptions of liability, endorsements, acknowledgments of assignment, and such other instruments as shall be effective to evidence and effect TRANSCO's assumption and agreement to pay, perform and discharge all Non-Generation Liabilities, as set forth on Schedule 1 to this Agreement.

(c) Appraisal and Valuation. An appraisal of the Non-Generation Assets as of June 30, 2000 will be completed (the "Preliminary Appraisal"). The Preliminary Appraisal shall be updated, or certified as still valid, by the appraiser as of the Closing Date (the "Final Appraisal"), as set forth in Section 2.4(d)(i) hereof.

For purposes of determining the amount of the purchase price for the Transmission Business, to be paid at Closing, the amount set forth in Section 2.4(d)(i) hereof shall be

determined on a preliminary basis based on the Preliminary Appraisal and projected financial statements and records as of June 30, 2000 (or later, if available prior to Closing). For the purposes of determining the Closing Purchase Price for the Transmission Business, the amount set forth in Section 2.4(d)(i) hereof shall be determined based on the Final Appraisal.

For purposes of determining the amount of the purchase price for the Transmission Business, to be paid at Closing, the TRANSCO M and E Allocation shall be determined on a preliminary basis based on AEPCO's financial statements and records as of June 30, 2000. For purposes of determining the Closing Purchase Price for the Transmission Business, the TRANSCO M and E Allocation shall be determined based on AEPCO's audited financial statements and records as of the Closing Date.

(d) Closing Purchase Price. Subject to Section 2.4(g) hereof, the Closing Purchase Price for the Transmission Business shall be the sum of:

(i) The fair market value of the Non-Generation Assets determined in the Final Appraisal as of the Closing Date; plus

(ii) The TRANSCO M and E Allocation which is determined as of the Closing Date in accordance with the applicable allocation formula prescribed in Schedule 3 of this Agreement: (a) expressed as a positive number, if the preliminary TRANSCO M and E Allocation determined pursuant to such Schedule 3 has a negative value on the Closing Date, or (b) expressed as a negative number, if the preliminary TRANSCO M and E Allocation determined pursuant to such Schedule 3 has a positive value on the Closing Date.

(e) Payment of Closing Purchase Price. TRANSCO shall pay for the Transmission Business by assuming, effective as of the Closing Date (as evidenced and effected by delivery of the TRANSCO Mortgage or other security instrument), the TRANSCO FFB Note(s), the TRANSCO RUS Note(s), the TRANSCO CFC Note (if required), the TRANSCO Assumption and Indemnity Agreements, substantially in the forms attached hereto as Exhibit A, that portion of AEPCO's debt secured under the AEPCO Mortgage which is determined by the allocation formula set forth on Schedule 3 to this Agreement and as based upon the Preliminary Appraisal and the projected financial statements and records as of June 30, 2000 with respect to the TRANSCO M and E Allocation (the "TRANSCO Assumed AEPCO Debt"). In the event that the Closing Purchase Price exceeds the TRANSCO Assumed AEPCO Debt, TRANSCO shall pay the difference to AEPCO in cash within thirty (30) days following the Close of Books Date. In the event that the TRANSCO Assumed AEPCO Debt exceeds the Closing Purchase Price, AEPCO shall pay the difference to TRANSCO in cash within thirty (30) days following the Close of Books Date. AEPCO shall obtain from RUS and CFC a release from the AEPCO Mortgage of the Transmission Business, including the Non-Generation Assets.

(f) Assignment of Right to Recover Regulatory Asset Charge. At the Closing, AEPCO shall convey, transfer, assign and deliver to TRANSCO, and TRANSCO will receive and pay for, through the assumption of an additional portion of AEPCO's debt secured under the AEPCO Mortgage, the regulatory assets set forth on Schedule 1 hereof,

and the right to recover the Regulatory Asset Charge (RAC) of AEPCO as set forth and approved by the ACC *In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues, Docket No. E-01773-A-98-0470.* The amount of the additional portion of AEPCO debt to be assumed by TRANSCO shall be equal to the "Regulatory Assets" set forth on Schedule 1 to this Agreement.

(g) Adjustment to Closing Purchase Price Resulting from Certain Events Subsequent to the Closing Date. Upon the occurrence of any Purchase Price Adjustment Event, the Closing Purchase Price for the Non-Generation Assets purchased by TRANSCO from AEPCO pursuant to this Agreement, as determined pursuant to Section 2.4 (d) hereof, shall be increased by an amount equal to the Purchase Price Adjustment, if any. The Purchase Price Adjustment, if any, shall be paid to AEPCO by TRANSCO in cash within ninety (90) days after the occurrence of the applicable Purchase Price Adjustment Event, or as AEPCO may otherwise agree in writing.

2.5 Transmission Arrangements. Prior to the Closing Date, or at the Closing, TRANSCO shall seek to execute and deliver, as appropriate, a Transmission Agreement, Network Service Agreement, Service Agreements for Firm and Non-Firm Transmission and Ancillary Services or other arrangements with AEPCO, each All Requirements Member and MEC, as appropriate, pursuant to which TRANSCO shall provide transmission and related services to AEPCO and MEC. The Network Service Agreement shall, among other things, permit the delivery by TRANSCO of capacity and energy from AEPCO to each All Requirements Member. Commencing as of the Effective Date, provided the approval of each of ACC, RUS, FERC, if required, and Financial Entities has been obtained: (i) the Transmission Agreement shall govern the purchase and sale of transmission service and Ancillary Services by and between TRANSCO and MEC; and (ii) the Network Service Agreement shall govern the purchase and sale of transmission service and Ancillary Services by and between TRANSCO and AEPCO along with other matters between TRANSCO and each All Requirements Member; and (iii) Service Agreements for Firm and Non-Firm Transmission and Ancillary Services shall govern the purchase and sale of other transmission service and Ancillary Services by and between TRANSCO and AEPCO. TRANSCO and CSP may enter into similar transmission arrangements and service agreements at such time as circumstances warrant. AEPCO and TRANSCO shall execute and deliver, on or before the Closing Date, the Network Service Agreement and the Service Agreements for Firm and Non-Firm Transmission and Ancillary Services.

2.6 Transfer of CSP Business. As soon as all required approvals and consents have been obtained and the conditions in Sections 7.1(d) and (e) herein, to the extent they relate to the transfer of the CSP Business to CSP and assumption by CSP of CSP Liabilities, have been satisfied or waived, AEPCO and CSP shall mutually determine the date of the commencement of the transfer to CSP of the CSP Business and the CSP Assets and Liabilities. AEPCO shall obtain from RUS and CFC a release from the AEPCO Mortgage of the CSP Business, including the CSP Assets. The transfer and sale of the CSP Business shall be completed on or before the Closing Date. AEPCO and CSP shall complete the sale, transfer and conveyance to and assumption by, CSP of the CSP Business, including CSP Assets as described in Schedule 2 to this Agreement, on or before the Closing Date for a purchase price (paid in cash) to be agreed to by the Boards of Directors of AEPCO and CSP, taking into consideration the Net Book Value of the CSP Assets as of the time

of such transfer and sale of the CSP Business and the assumption of the CSP Liabilities by CSP. The CSP Business, including the CSP Assets, shall be sold, transferred and conveyed by AEPCO to CSP free of the lien of the RUS and CFC under the AEPCO Mortgage. Prior to the Closing Date, AEPCO shall cause each Class A Member to complete the actions necessary to become a CSP Member. AEPCO and TRANSCO shall also become members of CSP and shall on or prior to the Closing Date cause the capital contributions to CSP to be made as in the amounts shown for AEPCO and TRANSCO on Schedule 8 hereto. CSP may from time to time admit additional members in accordance with the provisions of the CSP Bylaws as they may be amended from time to time thereafter.

2.7 Assumption of CSP Liabilities. On or before the Closing Date, and as a condition of the transfer of the CSP Business, CSP shall execute and deliver to AEPCO, and to such other persons and entities as may be appropriate, all assumptions of liabilities, endorsements, acknowledgment of assignment, and such other instruments as shall be effective to evidence and effect CSP's assumption of, and agreement to perform and discharge, all CSP Liabilities described on Schedule 2 to this Agreement.

2.8 AEPCO Employees. On or before the Closing Date, AEPCO will terminate the employment of all AEPCO Employees except for the AEPCO Retained Personnel. TRANSCO shall immediately thereupon make an offer of employment to the TRANSCO Employees on terms substantially comparable to their current employment by AEPCO. CSP shall also immediately make an offer of employment to the remaining AEPCO Employees, except for the AEPCO Retained Personnel and the TRANSCO Employees, on terms substantially comparable to their current employment by AEPCO. For the employees so employed by the Parties, the provision of benefits under the Employee Benefit Plans shall be pursuant to Section 2.11 hereof. This Section 2.8 does not and shall not be construed to create any rights (of continued employment beyond the Closing Date, or otherwise) in any employee or any other third party. AEPCO shall give the International Brotherhood of Electrical Workers Local No. 570 (the "IBEW") appropriate notice of the contemplated transfer of AEPCO Employees covered by the Collective Bargaining Agreement, dated March 1, 1996, or its successor agreement, between AEPCO and IBEW, and make such other notifications as may be required by Law.

2.9 Provision of Personnel Services. At or before the Closing Date, TRANSCO and CSP shall execute and deliver a Staffing Agreement, and AEPCO and CSP shall execute and deliver a Staffing Agreement, all substantially in the form as attached hereto as Exhibits B and C, respectively, subject to such non-material changes as the parties thereto may mutually agree upon. As of the Effective Date, CSP shall begin providing Personnel to provide operations, maintenance, administration, and other functions to AEPCO and TRANSCO pursuant to such Staffing Agreements. On or before the Closing Date and subject to applicable Law, AEPCO, TRANSCO and CSP shall each enter into employment arrangements with an individual to serve as the Chief Executive Officer of each of the Parties. Such Chief Executive Officer shall be responsible for the management and operation of CSP, AEPCO and TRANSCO pursuant to the delegation of authority and responsibility of each of the Boards of Directors of CSP, AEPCO and TRANSCO, respectively.

2.10 Office and Facility Space Leases. At or before the Closing, AEPCO, as lessor, and TRANSCO and CSP, as lessees, shall execute and deliver multiple office and facility space leases, all substantially in the form recommended by AEPCO's Executive Vice President and Chief

Executive Officer, subject to such changes as the parties thereto may mutually agree upon. As of, or before, the Effective Date, AEPCO shall begin leasing office and facility space to TRANSCO and CSP, respectively, pursuant to such office and facility space leases.

2.11 Employee Benefit Plans. As soon as practical after the Closing Date, AEPCO shall amend its "Employee Benefit Plans," as hereinafter defined, to permit the application of the Employee Benefit Plans to be apportioned between AEPCO, TRANSCO and CSP pertaining to the personnel employed by each. Each such Employee Benefit Plan shall be a single plan, with all plan assets transferred and available to pay benefits to participating employees of the Parties.

(a) Amendments To Be Adopted. Each such Employee Benefit Plan shall be amended: (i) to credit employees of CSP and TRANSCO with service with, and compensation paid by AEPCO, (ii) to authorize the Board of Directors of the Parties to effect the appointment of the plan administrator of such plan, and (iii) to authorize the Board of Directors of the Parties to cause the amendment of such plan, provided that any amendment that materially increases the benefit cost to the other Parties, pursuant to the Staffing Agreements, or otherwise shall be subject to the approval of the Board of Directors of such other Parties.

(b) Allocation of Costs. The benefit and administrative cost of each such Employee Benefit Plan shall be allocated among AEPCO, TRANSCO, and CSP in a manner determined by the actuary or contract administrator then engaged by the Parties on behalf of the Employee Benefit Plans, so as to most equitably allocate such costs, including extraordinary one time costs, to the Parties whose personnel or those contracted for are covered by the plan pursuant to the provisions of the Staffing Agreements, or otherwise. Such benefit and administrative costs related to personnel employed by CSP shall be recovered by CSP from AEPCO and TRANSCO pursuant to the relevant provisions of the Staffing Agreements, based upon the cost of providing service thereunder.

(c) Plans Covered. For purposes of this Section 2.11, "Employee Benefit Plan" shall include the following plans currently sponsored by AEPCO: (i) the NRECA Retirement & Security Program; (ii) the NRECA SelectrePension Plan; (iii) the NRECA Group Benefit Plan; (iv) the NRECA Flexible Spending Account Plan; (v) the NRECA ElectREWage (LTD) Plan; (vi) the NRECA ElectRELife Plan; (vii) the NRECA Deferred Compensation Plan; and (vii) the Business Travel Accident Insurance Plan.

2.12 Further Assurances. If at any time after the Closing Date, any further assignments or assurances are necessary or desirable to vest or to perfect or confirm, or record, of record in TRANSCO and CSP the title to any property or right included in the Non-Generation Assets subject to the easements, rights of way and possessory interests reserved by AEPCO pursuant to Section 2.4(a) hereof, as to TRANSCO, or the CSP Assets as to CSP, or to evidence and effect the assumption by TRANSCO or CSP of the Non-Generation Liabilities or the CSP Liabilities, respectively, or otherwise to carry out the provisions of this Agreement, the officers of AEPCO, TRANSCO and CSP shall, and are hereby authorized and empowered on behalf of such respective corporations, in the name of and on behalf of the appropriate corporation, to execute and deliver any and all things necessary or proper to vest or to perfect, confirm, and record title to such property or rights in TRANSCO (subject to the aforementioned easements, rights of way and possessory

interests reserved by AEPCO) or CSP, as appropriate, or to evidence and effect such assumption by TRANSCO or CSP, as the case may be.

2.13 Retail Competitive Electric Sales. In order to facilitate competitive retail electric sales of capacity and energy either from AEPCO's Resources or from other Resources acquired by CSP, CSP will engage in competitive retail electric sales activities. CSP shall seek to cause the execution and delivery by each All Requirements Member of a Joint Marketing Agreement substantially in the form attached hereto as Exhibit D no later than thirty (30) days following the Effective Date in order to facilitate effective competitive retail electric sales of electric energy and capacity in each such Member's Distribution Service Area. MEC and CSP may enter into a joint marketing agreement which is mutually acceptable for similar purposes in such Member's Distribution Service Area.

3. GOVERNANCE MATTERS:

3.1 New Governance. Subject to satisfaction of the conditions specified below prior to the final implementation of new governance or governance changes, respectively, provided by the TRANSCO Bylaws, the CSP Bylaws and any required AEPCO Bylaw Amendments, TRANSCO, CSP and AEPCO shall take appropriate steps on a timely basis to each elect new Boards of Directors in accordance with the then current Bylaws of each Party.

(a) Conditions to Final Implementation of Governance Changes. The terms of the individuals elected as the new Board of Directors of the Parties may commence, and the other governance changes required by the TRANSCO Bylaws, the CSP Bylaws, and any required AEPCO Bylaw Amendments may be implemented earlier than the Closing Date and prior to the receipt of the IRS Ruling described below. Such implementation of the governance of TRANSCO, and governance changes for AEPCO shall however be conditioned upon the receipt by TRANSCO and AEPCO of final, non-appealable determinations from the Internal Revenue Service (the "IRS Ruling") to the effect that the adoption and implementation of the TRANSCO Bylaws and any required AEPCO Bylaw Amendments, will not affect the Parties' status for federal income tax purposes as corporations operating on a tax-exempt cooperative basis. The Board of Directors of AEPCO, however, may waive the receipt of the IRS Ruling as a condition for implementation of AEPCO Bylaw Amendments.

(b) Possible Modifications. If any changes in the governance provisions contemplated by the TRANSCO Bylaws and any required AEPCO Bylaw Amendments, are required in order to obtain the IRS Ruling, AEPCO, TRANSCO and the Class A Members of AEPCO and the TRANSCO Members shall develop changes that are mutually acceptable to AEPCO, TRANSCO and the IRS subject, upon its execution, to the Member Agreement. Any such modification to such TRANSCO Bylaws or any AEPCO Bylaw Amendments, may be adopted only by the requisite vote prescribed by applicable Law and by such Party's Bylaws.

4. REPRESENTATIONS AND WARRANTIES OF AEPCO:

As of the Effective Date, AEPCO represents and warrants to TRANSCO and CSP as follows:

4.1 Organization and Qualification. AEPCO is a non-profit corporation duly organized, validly existing and in good standing under the generation and transmission electric cooperative Laws of the State of Arizona and: (i) has the corporate power and authority to own its properties and assets and to carry on its business as it is now being conducted, and (ii) is duly qualified to conduct business and is licensed and in good standing in all other jurisdictions where the nature of its properties or the conduct of its business so requires.

4.2 Authorization. AEPCO has the full corporate power and authority to execute and deliver this Agreement and each additional contract which this Agreement contemplates will be executed and delivered by AEPCO, as set forth on Schedule 6 hereto (each such contract being referred to as an "Additional AEPCO Contract"), and to consummate the transactions and actions required hereby and thereby on the part of AEPCO. The execution and delivery by AEPCO of this Agreement and each Additional AEPCO Contract and the consummation by AEPCO of the transactions and actions required hereby and thereby have been duly authorized by the Board of Directors of AEPCO, and the Class A Members of AEPCO have adopted any AEPCO Bylaw Amendments necessary to facilitate and permit such transactions and actions. This Agreement has been duly executed and delivered by AEPCO and is a valid agreement of AEPCO, enforceable against AEPCO in accordance with its terms, except to the extent that such enforceability is limited by bankruptcy and other Laws affecting creditors' rights generally and by principles of equity, including specific performance.

4.3 Non-Contravention. Except as may be specifically disclosed in Schedule 7 to this Agreement, the execution and delivery by AEPCO of this Agreement and each Additional AEPCO Contract and the consummation of the transactions and actions required hereby and thereby, do not and will not: (a) violate any provision of the Articles of Incorporation or Bylaws of AEPCO; (b) violate, or result (with the giving of notice or the lapse of time or both) in a violation of, or result in the acceleration of or entitle any person to accelerate (whether after the giving of notice or lapse of time or both) any obligation under, or result in the creation or imposition of any lien, charge, pledge, security interest or other encumbrance upon any of the property of AEPCO pursuant to, any provision of, any mortgage, lien, lease, agreement, instrument, Law, order or arbitration award to which AEPCO is a party or by which AEPCO or its properties is bound; (c) violate or conflict with any Law or other restriction of any kind or character to which AEPCO or its properties is subject or by which any assets of AEPCO may be bound; or (d) constitute an event permitting termination of any mortgage, lien, lease, agreement, license or instrument to which AEPCO is a party, in each case, if such violation, acceleration, entitlement to accelerate, creation or imposition of a lien, charge, pledge, security interest or other encumbrance, conflict, or event could reasonably be expected (when taken together with all such other violations, accelerations, entitlements to accelerate, creations and impositions of liens, charges, pledges, security interests and other encumbrances, conflicts, and events) to affect materially and adversely the business or properties of AEPCO or AEPCO's ability to consummate the transactions and actions required by this Agreement. Except as may be specifically disclosed in Schedule 7 of this Agreement, AEPCO is not (after diligent inquiry) knowingly in breach of, in default under, or in violation of, any applicable Law or the provisions of any permit, consent, authorization, variance or approval or in breach of, in default under, or in violation of, any provision of any promissory note, indenture or any evidence of indebtedness or security therefor, lease, contract, license or other agreement by which it is bound, except for any such breaches, defaults or violations which, individually or in the aggregate, could not reasonably be

expected to have a material adverse effect on the business or financial condition of AEPCO or its ability to fulfill its commitments hereunder.

4.4 Consents. Except for the approvals, rulings, filing, assurances, orders, registrations, forbearances, non-action, coordinations and authorizations contemplated in Sections 3.1(a) and 7.1(a), (c), (d), (e), (g), (h), (j), (l), (n), (o) and (q) and as identified in the Closing Memorandum, no consent, authorization, order or approval, or filing or registration with, any Governmental Authority is required to be made or obtained by AEPCO for, or in connection with, the execution and delivery by AEPCO of this Agreement and each Additional AEPCO Contract and the consummation by AEPCO of the transactions and actions required hereby and thereby, other than such as have been or, prior to the Closing Date, will be made or obtained or have been satisfied.

4.5 Access to Information. AEPCO has had adequate access to information regarding TRANSCO and CSP and the proposed restructuring.

4.6 Opinion of Counsel. On the Closing Date, AEPCO shall furnish to TRANSCO and CSP, individual opinions of counsel to AEPCO, dated as of the Closing Date, with a copy to CFC and RUS, acceptable to TRANSCO, CSP and RUS, as to the representations and warranties made by AEPCO in this Section 4.

4.7 No Pending Legal Actions. No suit, action, arbitration or legal, administrative or other proceeding is pending or threatened by or against AEPCO before any Governmental Authority or arbitral tribunal which would affect the validity or enforceability of this Agreement or the ability of AEPCO to fulfill its commitments hereunder and no investigation that may result in any such suit, action, arbitration or legal, administrative or other proceeding is pending or threatened by or against AEPCO. Except as set forth in Schedule 7 hereof, no such suit, action, arbitration or legal, administrative or other proceeding is pending or threatened that would, if adversely determined, reasonably be expected to have a material adverse effect on the condition of AEPCO.

5. REPRESENTATIONS AND WARRANTIES OF TRANSCO AND CSP:

As of the Effective Date, TRANSCO and CSP each separately represent and warrant as to itself to AEPCO and each other as follows, each such corporation making each representation and warranty severally as to itself only:

5.1 Organization and Qualification. TRANSCO is a non-profit corporation duly organized, validly existing and in good standing under the generation and transmission electric cooperative laws of the State of Arizona and is duly qualified to do business and is licensed and in good standing in all other jurisdictions where the nature of its properties or the conduct of its business so requires. CSP is a non-profit corporation duly organized, validly existing and in good standing under the generation and transmission electric cooperative laws of the State of Arizona. TRANSCO and CSP each have the corporate power and authority to own the properties and assets it will own following the Closing Date and to carry on its business as it will be conducted following the Closing Date.

5.2 Authorization. Each of TRANSCO and CSP has the full corporate power and authority to execute and deliver this Agreement and each additional contract which this Agreement contemplates will be executed and delivered by TRANSCO or CSP, as the case may be as set forth

on Schedule 6 hereto (each such contract being referred to as an "Additional TRANSCO Contract" or an "Additional CSP Contract," respectively) and to consummate the transactions and actions required hereby and thereby on the part of such corporation. The execution and delivery by such corporation of this Agreement and each Additional TRANSCO Contract or each Additional CSP Contract, as the case may be, and the consummation by such corporation of the transactions and actions required hereby and thereby have been duly authorized by the Board of Directors of such corporation. This Agreement has been duly executed and delivered by such corporation and is a valid agreement of such corporation, enforceable against such corporation in accordance with its terms, except to the extent that such enforceability is limited by bankruptcy and other Laws affecting creditors' rights generally and by principles of equity, including specific performance.

5.3 Non-Contravention. Except as may be specifically disclosed in Schedule 7 to this Agreement, the execution and delivery by such corporation of this Agreement and each Additional TRANSCO Contract or Additional CSP Contract, as the case may be, and the consummation of the transactions and actions contemplated hereby and thereby, do not and will not: (a) violate any provision of the Articles of Incorporation or Bylaws of such corporation; (b) violate, or result (with the giving of notice or the lapse of time or both) in a violation of, or result in the acceleration of or entitle any person to accelerate (whether after the giving of notice or lapse of time or both) any obligation under, or result in the creation or imposition of any lien, charge, pledge, security interest or other encumbrance upon any of the property of such corporation pursuant to, any provision of, any mortgage, lien, lease, agreement, instrument, Law, or arbitration award to which such corporation is a party or by which such corporation or its properties is bound; (c) violate or conflict with Law or any other restriction of any kind or character to which such corporation or its properties is subject or by which any assets of such corporation may be bound; or (d) constitute an event permitting termination of any mortgage, lien, lease, agreement, license or instrument to which such corporation is a party, in each case, if such violation, acceleration, entitlement to accelerate, creation or imposition of a lien, charge, pledge, security interest or other encumbrance, conflict, or event could reasonably be expected (when taken together with all such other violations, accelerations, entitlements to accelerate, creations and impositions of liens, charges, pledges, security interests and other encumbrances, conflicts, and events) to affect materially and adversely the business or properties of such corporation or such corporation's ability to consummate the transactions and actions required by this Agreement. Except as may be specifically disclosed in Schedule 7 of this Agreement, neither TRANSCO nor CSP, as applicable, is (after diligent inquiry) knowingly in breach of, in default under, or in violation of, any applicable Law or the provisions of any permit, consent, authorization, variance or approval or in breach of, in default under, or in violation of, any provision of any promissory note, indenture or any evidence of indebtedness or security therefor, lease, contract, license or other agreement by which it is bound, except for any such breaches, defaults or violations which, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on the business or financial condition of either TRANSCO or CSP, as applicable, or its ability to fulfill its commitments hereunder.

5.4 Consents. Except for the approvals, rulings, filings, assurances, orders, registrations, forbearances, non-action, coordinations and authorizations contemplated in Section 3.1(a) and 7.1(a), (c), (d), (e), (g), (h), (j), (l), (n), (o) and (q) and as identified in the Closing Memorandum, no consent, authorization, order or approval, or filing or registration with any Governmental Authority is required to be made or obtained by either CSP or TRANSCO for, or in connection with, the execution and delivery by such corporation of this Agreement and each Additional TRANSCO

Contract or Additional CSP Contract, as the case may be, and the consummation by such corporation of the transactions and actions required hereby, other than such as have been or, prior to the Closing Date, will be made or obtained or have been satisfied.

5.5 Access to Information. TRANSCO and CSP have had adequate access, to information provided by AEPCO regarding AEPCO, the Transmission Business, the CSP Business, and the proposed restructuring.

5.6 Opinions of Counsel. On the Closing Date, TRANSCO and CSP shall each furnish to AEPCO, and to each other, individual opinions of their respective counsel, dated as of the Closing Date, with copies to CFC and RUS, acceptable to AEPCO and each other, and RUS as to the individual representations and warranties made by TRANSCO and CSP in this Section 5.

5.7 No Pending Legal Actions. No suit, action, arbitration or legal, administrative or other proceeding is pending or threatened by or against TRANSCO or CSP before any Governmental Authority or arbitral tribunal which would affect the validity or enforceability of this Agreement or the ability of TRANSCO or CSP to fulfill its commitments hereunder and no investigation that may result in any such suit, action, arbitration or legal, administrative or other proceeding is pending or threatened by or against TRANSCO or CSP. Except as set forth in Schedule 7 hereof, no such suit, action, arbitration or legal, administrative or other proceeding is pending or threatened that would, if adversely determined, reasonably be expected to have a material adverse effect on the condition of TRANSCO or CSP.

6. ADDITIONAL COVENANTS AND AGREEMENTS:

6.1 Conduct of Business. AEPCO covenants that during the period from the date hereof to the Closing Date, it shall conduct its operations in the ordinary and usual course of business, except as otherwise provided for by this Agreement.

6.2 Interim Rates. Subject to any subsequent amendments or other changes by AEPCO's Board of Directors (and all necessary approvals thereof), the AEPCO rates applicable to the All Requirements Members under the Existing Wholesale Power Contracts shall continue in effect. On and after the Effective Date, the rate for electric services applicable to the Partial Requirements Member shall be as stated in, and become effective in accordance with, the Partial Requirements Capacity and Energy Agreement and the Transmission Agreement.

6.3 Consents and Authorizations. Each Party hereto will use its reasonable efforts to obtain all consents, authorizations, waivers, orders and approvals from any Governmental Authority and shall participate in making all related filings and registrations, which may be necessary or desirable in connection with the consummation of any of the transactions and actions required both by this Agreement and by each additional contract which this Agreement contemplates will be executed by such Party (each such contract applicable to a respective Party being referred to as an "Applicable Additional Contract") consistent with Section 7.2 hereof. Each Party also will use its reasonable efforts to obtain all consents, authorizations, waivers and approvals from any non-governmental third party which may be necessary or desirable in connection with the consummation of the transactions and actions required by this Agreement and by each Applicable Additional Contract. Each Party will cooperate fully with the other Parties in assisting them to

obtain such consents, authorizations, waivers, orders and approvals that the other Parties are required to obtain or make. Without in any way limiting the foregoing, the Parties shall use reasonable efforts to obtain the approval of the ACC, FERC, if required, and RUS (as well as the approvals and related actions by the Financial Entities where necessary) of the matters set forth in the Closing Memorandum, including releases of the lien held by RUS and CFC under the AEPCO Mortgage on the Transmission Business, including the Non-Generation Assets upon the recordation and the creation of the lien thereon under the TRANSCO Mortgage and the CSP Business, including the CSP Assets. AEPCO shall have primary responsibility for making such filings and seeking to obtain such consents, authorizations, waivers, orders and approvals.

6.4 IRS Ruling. AEPCO shall use its reasonable efforts to obtain a favorable tax determination from the Internal Revenue Service meeting the requirements of Section 3.1(a) hereof.

6.5 Access and Confidentiality.

(a) Access. TRANSCO and CSP as well as the Class A Members, RUS, CFC and the Financial Entities, shall continue to have reasonable access as required to the premises, books and records, officers and employees of AEPCO and at reasonable hours and the right to copy all books and records at their own expense relating to the Transmission Business and the CSP Business as may be necessary or desirable for the conduct of the Transmission Business and the CSP Business, respectively. The officers of AEPCO shall furnish TRANSCO and CSP with such financial and operating data and other information with respect to the Transmission Business and the CSP Business as may be reasonably requested from time to time. No provision set forth in this Section 6.5(a) shall require a Party to independently provide or make available any information regarding any other Party otherwise prohibited from disclosure by applicable Law.

(b) Confidentiality. Except as otherwise required in filings or submittals which any Party makes with regulatory entities, including the ACC and RUS, and the Financial Entities, any information which any Party provides to the other Parties or to the other Parties' Representatives, whether written or oral, which is confidential or identified as confidential shall be treated as confidential material (the "Confidential Material"), except that this definition shall not apply to information that is generally available to the public or becomes generally available to the public other than as a result of a disclosure by any receiving Party or its Representatives. For purposes of this Agreement, the term "Representatives" shall mean a Party's directors, officers, employees, attorneys, accountants, investment bankers, technical consultants, brokers, bankers and others engaged by such Party or intended to be engaged by such Party to advise it regarding the Confidential Material or the transactions required hereby or to assist in financing the transactions required hereby. It is hereby agreed that the Confidential Material will be used by the receiving Party and/or its Representatives only for purposes of evaluating and facilitating the transactions required hereby, and that the Confidential Material will be kept confidential by the receiving Party and its Representatives; so long as (i) any of the Confidential Material may be disclosed to the receiving Party's Representatives who need to know such Confidential Material for purposes relating to the transactions required hereby (it being understood that such Representatives shall be informed by the receiving Party of its obligation hereunder and shall be directed by the receiving Party to treat such Confidential Material confidentially), and (ii) any other disclosure of such Confidential Material may be made to which the providing Party has previously consented

in writing. The provisions of this Section 6.5(b) shall remain in effect for a period of three years after the date hereof; provided, however, that following the Effective Date, TRANSCO and CSP and their respective Representatives shall not be restricted hereunder with respect to any information regarding the Transmission Business and the CSP Business, respectively, excepting information the disclosure of which is prohibited by FERC Order No. 888 and Order No. 889.

6.6 Expenses. Whether or not the transactions and actions required by this Agreement are consummated, all costs and expenses (including attorneys' and accountants' fees) incurred in connection with this Agreement and the transactions and actions required hereby shall be the responsibility of the Party incurring such costs and expenses.

6.7 Publicity. AEPCO shall be responsible for any press releases or other public announcements through the Closing Date with respect to this Agreement (subject to the provisions of Section 6.8) and the transactions required hereby, and neither TRANSCO nor CSP shall act unilaterally in this regard without prior consultation with AEPCO.

6.8 Acting to Avoid and Notices of Breaches of Representations and Warranties. Each Party shall: (a) take such actions so that such Party's representations and warranties in this Agreement remain true and correct as of the Closing Date and shall not take any action that would cause such representations and warranties to cease to be true and correct; and (b) inform the other Parties hereto promptly of any facts or circumstances that could be reasonably expected to constitute or result in a breach of any of such Party's representations and warranties in this Agreement.

6.9 Additional Agreements. Subject to the terms and conditions herein provided, each of the Parties hereto agrees to use its reasonable efforts to take, or cause to be taken, all actions and to do, or cause to be done, all things necessary, proper or advisable to consummate and make effective, as soon as reasonably practicable, the transactions and actions contemplated by this Agreement, including execution and delivery by the appropriate Parties of the Applicable Additional Contracts.

7. CLOSING CONDITIONS:

7.1 Closing Conditions. Subject in each case to the rights of AEPCO (and the approval rights of ACC, Financial Entities, and RUS where applicable) to waive (in whole or in part) any condition pursuant to Section 7.3 hereof, each Party's obligation to execute the documents and to consummate the transactions and actions contemplated by this Agreement is subject to the fulfillment, to the reasonable satisfaction of such Party, of each of the following conditions, set forth in Sections 7.1(a) through 7.1(q) hereof, inclusive, prior to or contemporaneously with the Closing; provided, however, that the full implementation of governance changes of the Parties are subject only to the fulfillment (or waiver) of the conditions contained in Section 3.1 hereof, and provided further that the complete transfer of the CSP Business to CSP is subject only to the fulfillment (or waiver) prior to or contemporaneously with the Closing Date of the condition that the Parties receive such approvals and consents set forth in Sections 7.1(c) (iii) and (m) hereof that are specifically applicable to such transfer of the CSP Business and of the conditions contained in Sections 7.1(d) and (e) hereof to the extent they relate to the transfer of the CSP Business:

(a) Governance Changes. The condition set forth in Section 3.1(a) hereof, consisting of the receipt of the IRS Ruling, shall have been satisfied or waived in accordance with the provisions of Section 3.1(a) hereof; the TRANSCO Bylaws, CSP Bylaws and any AEPCO Bylaw Amendments shall have been implemented on a full and unconditional basis; and the terms of the individuals elected as the new members of the new Boards of Directors of the Parties pursuant to the TRANSCO Bylaws, CSP Bylaws and any AEPCO Bylaw Amendments shall have commenced.

(b) Member Agreement. The Member Agreement shall have been executed and delivered by and among all Class A Members, AEPCO, TRANSCO and CSP.

(c) ACC, FERC, Financial Entities, and RUS Approvals Necessary. ACC, RUS and Financial Entities (with respect to Section 7.1(c)(iii) and (iv) hereof) authorizations and approvals satisfactory to each Party, as required by applicable Law, shall have been received in relation to the following:

(i) The AEPCO Closing Date Allocation and Attribution;

(ii) The Partial Requirements Capacity and Energy Agreement;

(iii) The transfer of the Transmission Business to TRANSCO, the related release from the AEPCO Mortgage contemplated by Section 6.3 hereof (which release shall be joined in by CFC), the TRANSCO Assumption and Indemnity Agreements, the TRANSCO Mortgage, the TRANSCO FFB Note(s), the TRANSCO RUS Note(s), the TRANSCO CFC Note (if required), the transfer of the CSP Business and TSEPP to CSP, the related release from the AEPCO Mortgage contemplated by Section 6.3 hereof, and the assumption by CSP of the CSP Liabilities;

(iv) The AEPCO Mortgage, the AEPCO FFB Note(s), the AEPCO RUS Note(s), the AEPCO CFC Note, and the Loan Contracts;

(v) The Transmission Agreement, the Network Service Agreement, and the Service Agreements for Firm and Non-Firm Transmission and Ancillary Services;

(vi) The Resource Integration Agreement; and

(vii) The other transactions, actions, documents, consents, approvals and agreements contemplated by this Agreement to the extent AEPCO determines that approval by the ACC, Financial Entities, FERC, and RUS of such matters is necessary under Law.

(d) PUHCA (Public Utility Holding Company Act of 1935) Matters. A no-action letter shall have been obtained from the SEC to the effect that none of the members of TRANSCO or CSP shall be deemed an electric utility company or holding company within the meaning of the Public Utility Holding Company Act of 1935, as amended, or

there shall have otherwise been obtained assurance satisfactory to AEPCO, TRANSCO and CSP that the Parties will either be exempt from compliance or be in compliance with such Act and related regulations of the SEC.

(e) Federal Power Act Matters. There shall have been obtained assurance satisfactory to AEPCO, CSP and TRANSCO that the Parties will either be exempt from compliance or be in compliance with the Federal Power Act and related regulations of FERC, including the filing of a power marketing authorization application for CSP.

(f) No Injunction. There shall be no judgment, decree, injunction, ruling or order of any Governmental Authority outstanding against AEPCO, TRANSCO or CSP which prohibits, restricts or delays consummation of the transactions and other actions contemplated hereby or limits the right of TRANSCO to control in any material respect the Transmission Business after the Closing or the right of CSP to control in any material respect the CSP Business after the transfer of such business to CSP.

(g) Approval of Assignments of Transmission Business Agreements. There shall have been obtained all necessary third party approvals of assignments to TRANSCO of all Transmission Business Agreements described in Schedule 5 to this Agreement.

(h) Other Consents and Authorizations. In addition to the approvals described under any of the foregoing provisions of this Section 7.1, and Section 7.1(p) hereof, all other consents, authorizations, waivers, orders and approvals of, and filings and registrations with, any Governmental Authority or any non-governmental third party which are required for or in connection with the execution, delivery and performance by AEPCO, TRANSCO and CSP of this Agreement, the Member Agreement, and each Applicable Additional Contract and the consummation by AEPCO, TRANSCO and CSP of the transactions and actions required hereby shall have been obtained or made or satisfied.

(i) Representations and Warranties and Compliance With Covenants and Obligations. In the case of each Party: (A) the representations and warranties of each of the other Parties contained in this Agreement shall have been true and correct at the date hereof and also shall be true and correct in all material respects at and as of the Closing with the same force and effect as if made at and as of the Closing; (B) each of the other Parties shall have performed and complied in all material respects with all agreements and covenants required by this Agreement to be performed or complied with by it at or prior to the Closing; and (C) each Party shall have received one or more certificates of the Chief Executive Officer or other senior executive officer of each of the other Parties certifying, to the best of his or her knowledge, all of the foregoing effects and that such representations and warranties are true and correct as of the respective dates thereof.

(j) Partial Requirements Capacity and Energy Agreement. The Partial Requirements Capacity and Energy Agreement shall have been fully executed, delivered and approved by ACC and RUS for the Partial Requirements Member.

(k) Membership In TRANSCO. The Class A Members, AEPCO and CSP shall have completed the actions necessary to become members of TRANSCO.

(l) Transmission Arrangements. A Transmission Agreement between TRANSCO and the Partial Requirements Member, a Network Service Agreement between TRANSCO, AEPCO and each All Requirements Member, and Service Agreements for Firm and Non-Firm Transmission and Ancillary Services between TRANSCO and AEPCO shall have been fully executed, delivered and approved by ACC, FERC, and RUS, where necessary.

(m) Membership In and Capitalization of CSP. The Class A Members, AEPCO and TRANSCO shall have completed the actions necessary to become Members of CSP and AEPCO and TRANSCO shall have agreed to make capital contributions required pursuant to Section 2.6 of this Agreement.

(n) Resource Integration Agreement. The Resource Integration Agreement among AEPCO, TRANSCO, CSP and MEC shall have been executed, delivered and approved by ACC, FERC and RUS, where necessary.

(o) Tax Matters. There shall have been obtained assurance satisfactory to AEPCO, CSP and TRANSCO as to the amount of transaction privilege taxes, if any, assessed, or expected to be, by the Arizona Department of Revenue and any city or town having jurisdiction associated with the transfer of the Non-Generation Assets from AEPCO to TRANSCO and the CSP Assets from AEPCO to CSP.

(p) Opinions of Counsel and Certified Resolutions. All opinions of counsel to each Class A Member, AEPCO, TRANSCO and CSP and all certificates from each Class A Member, AEPCO, TRANSCO and CSP as to such legal matters as ACC and RUS shall require to be covered by any opinions or certificates and all certified resolutions evidencing approval of the Member Agreement and each Applicable Additional Contract in the form required by ACC and RUS, shall have been delivered.

(q) Stranded Cost Order. The ACC shall have issued an order in ACC Docket No. E-01773 A-98-0470 *In the Matter of the Application by Arizona Electric Power Cooperative, Inc., for Approval of its Filing as to Regulatory Assets and Transition Revenues.*

7.2 Regulatory and Contractual Approvals. Each Party hereto will use reasonable efforts to obtain all required consents, authorizations, waivers, orders and approvals from RUS, FERC, ACC and the Financial Entities of this Agreement and the allocations, agreements, transfers, releases, understandings, transactions, and actions set forth or contemplated in Section 7.1(c), (j), (l) and (n) hereto. Should RUS, ACC, FERC and/or Financial Entities disapprove of this Agreement, or any document or action set forth, or contemplated, in Section 7.1(c), (j), (l) and (n) hereto for which its approval is required, or require material changes or material modifications thereto that are unacceptable to any Party, the Parties shall negotiate in good faith to modify, within one hundred eighty (180) days of the receipt of the written notice of disapproval or unacceptable modification requirement from RUS, FERC, ACC and/or Financial Entities, this Agreement and/or the document or action set forth, or contemplated, in Section 7.1(c), (j), (l) and (n) hereto to which such disapproval or unacceptable modification requirement specifically pertains, in order to attempt to obtain such approval. In the event that such negotiation is unsuccessful and the Parties fail to

obtain the requisite consent, authorization, waiver, order or approval, this Agreement and any document or action set forth, or contemplated, in Section 7.1(c), (j), (l) and (n) hereto shall be or become null and void and shall not be binding on any Party for any purpose except for the provisions or actions set forth, or contemplated, in Section 9.3 and 9.4 hereof.

7.3 Waiver of Conditions. At its option, the Board of Directors of AEPCO, by unanimous vote, may waive any or all of the conditions (in whole or in part) contained in Sections 7.1(a), (g), (i), (k), and (m).

8. CLOSING:

8.1 Closing. Evidence of the fulfillment or waiver of the conditions set forth in Section 7 hereof shall be provided by AEPCO to the other Parties and to each Class A Member, and all documents and payments required to be delivered or made or otherwise necessary or desirable to consummate the transactions contemplated hereby, including such documents described in Section 7 hereof and the Closing Memorandum shall be executed and delivered and paid, by the Parties hereto to each other and to each of the Class A Members at the Closing to be held at the law offices of Chandler, Tullar, Udall & Redhair, 33 North Stone Avenue, Tucson, Arizona, at 10 a.m. Mountain Standard Time, on _____, 200___ (or at such other date, time and place as the Parties may mutually agree). If the Parties mutually agree to reschedule the Closing from _____ to another date, the Parties also shall cooperate with each other to make and appropriately document all adjustments as may be necessary or desirable in other dates contained in this Agreement which relate to the timing of the Closing.

8.2 Pre-Closing. The Parties hereto shall cooperate with one another and shall seek the cooperation of the Class A Members so that: (a) a pre-closing (the "Pre-Closing") can occur at the offices of Chandler, Tullar, Udall & Redhair on a date and at a time to be set by the AEPCO Board (on or before _____, or at such other date, time and place as the Parties may mutually agree); and (b) all documents that are required as a condition to Closing, as described in the Closing Memorandum, can be executed and delivered at or before such Pre-Closing, with such delivery being either to each other or to Chandler, Tullar, Udall & Redhair to be held in escrow until the Closing Date and be delivered on the Closing Date. The Parties hereto agree, and the Parties shall seek to obtain agreement in the Member Agreement from each party thereto, that any document delivered in escrow to Chandler, Tullar, Udall & Redhair may be delivered on the Closing Date to the appropriate recipient(s) without further authorization, unless Dwight M. Whitley, Jr. of Chandler, Tullar, Udall & Redhair actually receives a written notice from the Party or Class A Member that executed such document: indicating that a representation, warranty, certification, opinion or similar matter in such document is no longer true; setting forth the specific reason why such document cannot be delivered; and providing a substitute document which conforms as nearly as possible to the requirements applicable to the original document as set forth in this Agreement.

8.3 Deliveries At or Prior to the Closing Date. Provided that all applicable conditions to the transfer of the CSP Business have been satisfied or waived, at or prior to the Closing Date (or any mutually agreed date for Pre-Closing), AEPCO, TRANSCO and CSP shall execute and deliver all documents necessary or desirable to consummate such transaction and evidence the satisfaction or waiver of applicable conditions.

9. TERMINATION AND ABANDONMENT:

9.1 Termination and Abandonment. This Agreement and all transactions and actions contemplated hereby may be terminated and abandoned in either manner set forth below at any time upon notice to the Administrator prior to the Closing Date, notwithstanding any earlier implementation of the effectiveness of any AEPCO governance changes contemplated by, and effected pursuant to, Section 3:

(a) By mutual agreement of the Parties, or

(b) By AEPCO, pursuant to the unanimous consent of the Class A Members' directors on the AEPCO Board of Directors, if any condition set forth in Section 7.1 hereof shall not have been complied with or performed in any material respect and such non-compliance or non-performance shall not have been cured or eliminated (or by its nature cannot be cured or eliminated other than by waiver by AEPCO pursuant to Section 7.3 hereof) on or before January 1, 2002.

9.2 Procedure for Termination. The termination and abandonment of this Agreement and/or any of the transactions and actions contemplated hereby under Section 9.1(b) hereof shall be effective only when AEPCO provides written notice, signed by AEPCO, stating the grounds for such termination and abandonment, to the other Parties.

9.3 Effect of Termination. In the event of the termination and abandonment of this Agreement or any of the transactions and actions contemplated hereby, no Party shall have any liability if such termination and abandonment is by mutual agreement pursuant to Section 9.1(a) hereof. No Party hereto shall have any liability or obligation under this Agreement if this Agreement and/or any of the transactions and actions contemplated hereby are otherwise terminated or abandoned in accordance with Section 9.1 hereof, unless the failure to consummate or fulfill a condition is within the reasonable control of a Party, in which case such Party or Parties having such reasonable control shall continue to be bound by this Agreement.

9.4 Transfer of CSP Business. In the event of the termination and abandonment of this Agreement or any of the transactions and actions contemplated hereby under Section 9.1 hereof after the commencement of the transfer of the CSP Business and if such commencement of the transfer of the CSP Business occurred prior to the Closing Date, then the CSP Business, including the AEPCO Employees hired by CSP shall be transferred back to AEPCO with the allocation of full costs or damages to such Party or Parties as provided in Section 9.3 herein. In order to accomplish the reconveyance of any CSP Assets transferred prior to such termination and abandonment, CSP shall reconvey ownership of such CSP Assets to AEPCO for the consideration therefor paid by CSP to AEPCO, if any. In order to accomplish such transfer of the AEPCO Employees hired by CSP from the CSP to AEPCO the applicable procedures set forth in Sections 2.8 and 2.11, except for Section 2.11(b), shall be followed; except that CSP shall undertake the actions contemplated therein for AEPCO, and AEPCO shall undertake take the actions contemplated therein for CSP.

10. MISCELLANEOUS:

10.1 Survival. The covenants and other provisions contained in Sections 1, 2.4(d), 2.4(e), 2.4(f), 2.4(g), 2.6, 2.8, 2.10, 2.11, 2.12, 2.13, 3.1(b), 4.2, 4.4, 5.2, 5.4, 6.2, 6.3, 6.5, 6.6, 6.9, 10.1, 10.2, 10.3, 10.4, 10.9, 10.10, 10.11, 10.12, and 10.13 and Schedules 4, 5, 6 and 8 and Exhibits A,

B, C and D shall survive the Closing. All other covenants and provisions contained in this Agreement shall not survive the Closing and all such covenants and provisions and any conditions contained therein shall be deemed to have been waived; provided, however, that all representations and warranties made pursuant to the provisions of this Agreement shall have been true and correct as of the Closing Date. The executory covenants and other provisions of this Agreement maturing or otherwise becoming effective upon the Closing shall terminate on the Closing Date in accordance with their terms. Consistent with the rights of survival set forth herein, the other covenants and provisions of this Agreement shall subsist to the extent applicable until performed.

10.2 Specific Performance. The Parties hereto acknowledge that the rights of the other Parties under this Agreement to consummate the transactions required hereby are special, unique, and of extraordinary character, and that, in the event that any Party violates or threatens to violate or fails and refuses to perform any covenant made by it herein, then the other Parties hereto will be without adequate remedy at law. Therefore, each Party agrees, that, in the event it violates, breaches, threatens to violate or breach, or fails and refuses to perform any covenant made by it herein, then the other applicable Party or Parties hereto, so long as it or they are not in breach hereof, may, in addition to any remedies at law, institute and prosecute an action in a court of competent jurisdiction to enforce specific performance of such covenant or seek any other equitable relief against the defaulting Party.

10.3 Waiver. The failure of any Party hereto at any time or times to require performance of any provisions hereof shall in no manner affect the right to enforce the same. No waiver by any Party of any condition, or the breach of any term, provision, warranty, representation, agreement or covenant contained in this Agreement or the other contracts required hereby, whether by conduct or otherwise, in any one or more instances shall be deemed or construed as a further or continuing waiver of any such condition or breach or a waiver of any other condition or of the breach of any other term, provision, warranty, representation, agreement or covenant herein or therein contained.

10.4 Notices. All communications, notices, requests, demands, authorizations, consents, waivers or other modifications provided, permitted or required by this Agreement shall be communicated in writing or by a telecommunications device capable of creating a written record, and any such notice shall become effective: (a) upon personal delivery thereof, including, without limitation, by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by such a telecommunications device, upon transmission thereof, provided such transmissions promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to each Party hereto at its address set forth below or, in the case of any such Party hereto, at such other address as such Party may from time to time designate by written notice to the other Parties hereto or to such other address as any of the Parties hereto may from time to time designate.

If to AEPCO: Arizona Electric Power Cooperative, Inc.
P.O. Box 670
1000 South Highway 80
Benson, Arizona 85602
Attention: Executive Vice President and Chief Executive Officer
Fax: (520) 586-5576 -or- 5402

If to TRANSCO: Southwest Transmission Cooperative, Inc.
P.O. Box 2195
1000 South Highway 80
Benson, Arizona 85602
Attention: Chief Executive Officer
Fax: (520) 586-5279

If to CSP: Sierra Southwest Cooperative Services, Inc.
P.O. Box 2165
1000 South Highway 80
Benson, Arizona 85602
Attention: Chief Executive Officer
Fax: (520) 586-5332

10.5 Counterparts and Facsimile Delivery. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Any Party may deliver an executed copy of this Agreement and an executed copy of any documents contemplated hereby by facsimile transmission to another Party, subject to the requirements of Section 10.4 hereof, except when the Law expressly requires physical delivery with respect to stock certificates or other special types of documents, and such delivery shall have the same force and effect as any other delivery of a manually signed copy of this Agreement or such other document.

10.6 Headings. The headings herein are for convenience of reference only, do not constitute a part of this Agreement, and shall not be deemed to limit or affect any of the provisions hereof.

10.7 Amendment. Subject to RUS review and approval, this Agreement may be amended at any time prior to Closing by AEPCO, TRANSCO and CSP by written instrument executed by all of the Parties.

10.8 Severability. If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any rule of Law, all other terms and provisions of this Agreement will nevertheless remain in full force and effect so long as the economic or legal substance of the transactions and other actions required hereby is not affected in any material and adverse manner with respect to any Party hereto or any Class A Member. Upon a determination that any term or other provision is invalid, illegal or incapable of being enforced, the Parties hereto will negotiate in good faith to modify this Agreement so as to effect the original intent of the Parties and to maintain the positions of the Class A Members as closely as possible in an acceptable manner to the end that the transactions and other actions required by this Agreement are consummated to the extent possible.

10.9 Whole Agreement, Rights, Assigns and Laws. This Agreement (a) constitutes and documents, together with all other agreements required hereby (provisions of which remain in full force) the entire agreement and, except as otherwise specifically provided, supersedes all prior inconsistent agreements and understandings, both written and oral, among the Parties, with respect

to the specific subject matter hereof; (b) is not intended to change, amend or modify any other existing agreement among the Parties or some of them which is not expressly amended in the provisions of this Agreement; (c) is not intended to confer upon any person other than the Parties hereto any rights or remedies hereunder; (d) shall not be assigned, by operation of Law or otherwise; and (e ) shall be governed in all respects, including validity, interpretation and effect, by the laws of the State of Arizona without giving effect to its conflicts of law principles.

10.10 Waiver of Trial by Jury. Any suit, action or proceeding, whether claim, counterclaim or crossclaim, brought or instituted by any Party against another Party hereto on or with respect to this Agreement or any event, transaction or occurrence arising out of or in any way connected with this Agreement shall be tried only by a court and not by a jury. **EACH PARTY HEREBY EXPRESSLY WAIVES ANY RIGHT TO A TRIAL BY JURY IN ANY SUCH SUIT, ACTION OR PROCEEDING. THIS WAIVER OF RIGHT TO TRIAL BY JURY IS GIVEN KNOWINGLY AND VOLUNTARILY BY EACH PARTY, AND IS INTENDED TO ENCOMPASS INDIVIDUALLY EACH INSTANCE AND EACH ISSUE AS TO WHICH THE RIGHT TO A TRIAL BY JURY WOULD OTHERWISE ACCRUE. A PARTY MAY FILE A COPY OF THIS PARAGRAPH IN ANY PROCEEDING AS CONCLUSIVE EVIDENCE OF A PARTY'S WAIVER OF RIGHT TO TRIAL BY JURY.**

10.11 Attorneys' Fees and Legal Expenses. If any arbitration proceeding or action shall be brought to recover any amount under this Agreement, or for, or on account of any breach of, or to enforce or interpret any of the terms, covenants, or conditions of this Agreement, the prevailing Party shall be entitled to recover from the other Party, as part of the prevailing Party's costs, reasonable attorneys' fees, the amount of which shall be fixed by the arbitrators or by the court, and shall be made a part of any award or judgment rendered.

10.12 Venue. The proper venue for any proceeding at law or in equity or under the provisions for arbitration shall be Maricopa County, Arizona, and the Parties waive any right to object to the venue.

10.13 No Duty to Third Parties. Except with respect to the Financial Entities, (i) this Agreement is for the sole benefit of the Parties hereto, and nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any person not a party to this Agreement; (ii) no person (excepting the Parties) shall have any rights or interest, direct or indirect, in this Agreement; and (iii) the Parties specifically disclaim any intent to create any rights in any person as a third-party beneficiary to this Agreement.

10.14 Effectiveness. This Agreement shall be effective as of the date first above written and shall remain in effect among the Parties until terminated in accordance with Section 9 hereof, unless a provision shall survive in accordance with Section 10.1 hereof.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed, and their seals affixed, on the date first above written.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
(A NON-PROFIT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE CORPORATION)

By: George P. Davies
Name: George P. Davies
Title: President

Attest:

By: Richard G. Lunt
Name: Richard G. Lunt
Title: Secretary

SOUTHWEST TRANSMISSION COOPERATIVE, INC.
(A NON-PROFIT GENERATION AND TRANSMISSION COOPERATIVE CORPORATION)

By: Curtis Nolan
Name: Curtis Nolan
Title: Chairman

Attest:

By: Barbara Stockwell
Name: Barbara Stockwell
Title: Secretary-Treasurer

SIERRA SOUTHWEST COOPERATIVE SERVICES, INC.
(A NON-PROFIT GENERATION AND TRANSMISSION
COOPERATIVE CORPORATION)

By: _____
Name: L. Nick Buckelew
Title: Chairman

Attest:

By: _____
Name: Creden W. Huber
Title: Secretary

# Schedule 1 to the Restructuring Agreement:

Non-Generation Assets & Liabilities

## Non-Generating Assets:


| | Page Reference |
|---|---|
| A. Transmission Plant & Property | Pg A.1 |
| B. Transmission Line Detail | Pg B.1 thru B.6 |
| C. Transmission Substation Detail | Pg C.1 thru C.2 |
| D. Communications & Microwave Equipment | Pg D.1 thru D.2 |
| Microwave Structures | |
| Communication Equipment | |
| E. General Plant Equipment (Non-Generation) | |
| Transportation Equipment | Pg E.1 thru E.2 |
| Stores Equipment | Pg E.3 |
| Tools, Shop, Garage Equipment | Pg E.4, E.9-E.12 |
| Laboratory Equipment | Pg E.5, E.9-E.12 |
| Power Operated Equipment | Pg E.6 |
| Miscellaneous Equipment | Pg E.7 |
| Other Equipment | Pg E.8 |
| F. Intangible Plant | Pg F.1 thru F.5 |
| G. Construction Work in Progress | Pg G.1 thru G.3 |
| H. Land, Right-of-Way, & Lease Details | Pg H.1 thru H.9 |
| I. Financial & Other Assets | Pg I.1 |
| J. Regulatory Assets | Pg J.1 |


## Non-Generating Liabilities:


| | |
|---|---|
| K. Non-Generating Liabilities | Pg K.1 |


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Footnote:

Assets allocated from AEPCO to TRANSCO on basis of Utility Plant: Patronage from investments in associated organizations, CFC Capital Term Certificates, investment in CSP, Special Funds – restructuring related, general funds, net accounts receivable for ACC assessments, prepayments, unamortized discounts and unamortized losses on reaquired debt.

Assets allocated from AEPCO to TRANSCO on basis of employee headcount or other employee related: Deferred compensation, SFAS-106 APBO &, accrued payroll & payroll overhead temporary investment offsets, and employee accounts receivable.

Assets allocated from AEPCO to TRANSCO on basis other than utility plant or employee related: Misc. special funds and deposits, misc. temporary investments, energy receivables, prepaid land rights and rights of way, preliminary surveys, job tickets, and other misc. deferred debits

## Schedule 1 to the Restructuring Agreement

Transmission Plant and Property
(as of 6/30/00)

| | RUS 101 (1) | RUS 106 RUS 107 (2) | Total Plant (3) | Accum. Depr. | Net Plant | Page Reference |
|---|---|---|---|---|---|---|
| **Transmission Lines** | | | | | | Pg B.1 thru B.6 |
| RUS 350 - Land & Land Rights | 1,140,422 | 0 | 1,140,422 | 0 | 1,140,422 | |
| RUS 354 - Towers & Fixtures | 8,190,835 | 0 | 8,190,835 | (4,393,133) | 3,797,702 | |
| RUS 355 - Poles & Fixtures | 17,158,000 | 6,661,322 | 23,819,322 | (9,217,762) | 14,601,560 | |
| RUS 356 - Overhead Conductors & Devices | 15,261,029 | 389,604 | 15,650,633 | (8,242,408) | 7,408,225 | |
| RUS 359 - Roads & Trails | 125,405 | 18,485 | 143,890 | (68,534) | 75,356 | |
| subtotal Transmission Lines | 41,875,691 | 7,069,411 | 48,945,102 | (21,921,837) | 27,023,265 | |
| **Transmission Substations** | | | | | | Pg C.1 thru C.2 |
| RUS 350 - Land & Land Rights | 15,909 | 0 | 15,909 | 0 | 15,909 | |
| RUS 352 - Structures & Improvements | 3,116,682 | 0 | 3,116,682 | (1,312,579) | 1,804,103 | |
| RUS 353 - Station Equipment | 28,765,078 | 11,560,242 | 40,325,320 | (15,864,937) | 24,460,383 | |
| subtotal Transmission Substations | 31,897,669 | 11,560,242 | 43,457,911 | (17,177,516) | 26,280,395 | |
| **Communications & Microwave Equipment** | | | | | | Pg D.1 thru D.2 |
| RUS 389 - Land & Land Rights | 3,427 | 0 | 3,427 | 0 | 3,427 | |
| RUS 390 - Microwave Structures | 316,131 | 0 | 316,131 | (136,435) | 179,696 | |
| RUS 397 - Communications Equipment | 3,008,538 | 8,118,213 | 11,126,751 | (3,158,831) | 7,967,920 | |
| subtotal Communications | 3,328,096 | 8,118,213 | 11,446,309 | (3,295,266) | 8,151,043 | |
| **General Plant Equipment** | | | | | | |
| RUS 392 - Transportation Equipment | 1,026,550 | 0 | 1,026,550 | (664,301) | 362,249 | Pg E.1 thru E.2 |
| RUS 393 - Stores Equipment | 19,288 | 0 | 19,288 | (20,958) | (1,670) | Pg E.3 |
| RUS 394 - Tools, Shop, Garage Equipment | 138,210 | 43,954 | 182,164 | (95,546) | 86,618 | Pg E.4, E.9 |
| RUS 395 - Laboratory Equipment | 262,641 | 81,859 | 344,500 | (192,774) | 151,726 | Pg E.5, E.9 |
| RUS 396 - Power Operated Equipment | 1,951,050 | 0 | 1,951,050 | (1,262,563) | 688,487 | Pg E.6 |
| RUS 398 - Misc. Equipment | 113,449 | 0 | 113,449 | (59,343) | 54,106 | Pg E.7 |
| RUS 399 - Other Intangible Equipment | 162,817 | 0 | 162,817 | (109,415) | 53,402 | Pg E.8 |
| subtotal General Plant | 3,674,005 | 125,813 | 3,799,818 | (2,404,900) | 1,394,918 | |
| **Intangible Plant** | | | | | | |
| RUS 105 - Held for Future Use | 377,214 | 0 | 377,214 | 0 | 377,214 | Pg F.5 |
| RUS 114 - Electric Aquisition Adjustment | 4,413 | 0 | 4,413 | (4,413) | 0 | Pg F.1 |
| RUS 301 - Organization Costs | 1,515 | 0 | 1,515 | 0 | 1,515 | Pg F.2 |
| RUS 302 - Franchise | 248 | 0 | 248 | 0 | 248 | Pg F.3 |
| RUS 303 - Intangible Plant | 2,153,995 | 0 | 2,153,995 | (733,069) | 1,420,926 | Pg F.4 |
| subtotal Intangible Plant | 2,537,385 | 0 | 2,537,385 | (737,482) | 1,799,903 | |
| **Construction Work in Progress** | | | | | | Pg G.1 thru G.6 |
| Transmission Budget Purpose 2 | 0 | 2,203,705 | 2,203,705 | 0 | 2,203,705 | |
| General Budget Purpose 3 | 0 | 4,555 | 4,555 | 0 | 4,555 | |
| subtotal CWIP | 0 | 2,208,260 | 2,208,260 | 0 | 2,208,260 | |
| Grand Total Utility Plant in Service | 83,312,846 | 29,081,939 | 112,394,785 | (45,537,001) | 66,857,784 | |

(1) RUS 101 = Plant in Service
(2) RUS 107/RUS 106 = Construction Work in Progress/ Completed Construction - Unclassified
(3) Sum of (1) & (2) above

## Schedule 1 to the Restructuring Agreement

Transmission Line Detail
(as of 6/30/2000)

RUS 350 LAND & LAND RIGHTS - PLANT

| | TAX DIST | TOTAL | Actual Depr | Book Value |
|---|---|---|---|---|
| WW SOUTH/ EL SOL | 2800 | 18,478 | | 18,478 |
| | 2500 | 78,195 | | 78,195 |
| | 4400 | 25,111 | | 25,111 |
| | 1100 | 7,704 | | 7,704 |
| | 8600 | 60,555 | | 60,555 |
| | 6500 | 21,532 | | 21,532 |
| | 7900 | 16,283 | | 16,283 |
| | 4000 | 153,442 | | 153,442 |
| | 9200 | 11,899 | | 11,899 |
| | 5100 | 114,404 | | 114,404 |
| | 2000 | 49,686 | | 49,686 |
| | 400 | 111,236 | | 111,236 |
| | 2400 | 116,657 | | 116,657 |
| | 3000 | 106,688 | | 106,688 |
| | 8900 | 107,988 | | 107,988 |
| | | 0 | | 0 |
| WW EL SOL/WW | 1100 | 28,792 | | 28,792 |
| | | 0 | | 0 |
| WW VAIL/SOUTH | 2000 | 46,944 | | 46,944 |
| | 1000 | 64,828 | | 64,828 |
| | | 1,140,422 | | 1,140,422 |

RUS 354--TOWERS & FIXTURES - PLANT

| | VOLT LEVEL | TAX DIST | | | |
|---|---|---|---|---|---|
| APACHE/115KV SUB | 115 | 2600 | 145,107 | 82,786 | 62,321 |
| APACHE/REDTAIL | 230 | 2600 | 161,267 | 84,258 | 77,009 |
| BUTTERFIELD clas 106 | 230 | 900 | 103,905 | 26,832 | 77,073 |
| DAVIS DAM/RIVIERA | 230 | 1579 | 27,396 | 9,707 | 17,689 |
| GREENLEE SUB | 345 | 230 | 23,522 | 12,290 | 11,232 |
| HACKBERRY/DOS COND | 230 | 570 | 145,774 | 72,661 | 73,113 |
| KARTCH SUB FR SSVEC | 230 | 6930 | 13,921 | 8,611 | 5,310 |
| KARTCHNER SUB | 230 | 6930 | 25,583 | 15,825 | 9,758 |
| MORENCI/HACKBERRY | 230 | 200 | 53,255 | 27,824 | 25,431 |
| MORENCI/HACKBERRY | 230 | 200 | 75,270 | 39,327 | 35,943 |
| MORENCI/HACKBERRY | 230 | 200 | 89,804 | 46,920 | 42,884 |
| PANTANO SUB | 230 | 2000 | 71,647 | 44,318 | 27,329 |
| SAN RAFAEL SUB | 230 | 6830 | 174,034 | 44,942 | 129,092 |
| VAIL/BICKNELL | 345 | 3000 | 301,909 | 172,245 | 129,664 |
| VAIL/BICKNELL | 345 | 3000 | 29,503 | 18,250 | 11,253 |
| VAIL/BICKNELL | 345 | 3000 | 29,503 | 18,250 | 11,253 |
| WW EL SOL/WESTWING | 345 | 1100 | 122,290 | 62,424 | 59,866 |
| WW EL SOL/WESTWING | 345 | 1160 | 19,964 | 10,910 | 9,054 |
| WW EL SOL/WESTWING | 345 | 8900 | 533,536 | 291,575 | 241,961 |
| WW SOUTH/ EL SOL | 345 | 6500 | 388,681 | 212,413 | 176,268 |
| WW SOUTH/ EL SOL | 345 | 2800 | 79,061 | 43,207 | 35,854 |
| WW SOUTH/ EL SOL | 345 | 5100 | 691,986 | 378,169 | 313,817 |
| WW SOUTH/ EL SOL | 345 | 2400 | 639,852 | 349,677 | 290,175 |
| WW SOUTH/ EL SOL | 345 | 2000 | 233,284 | 127,489 | 105,795 |
| WW SOUTH/ EL SOL | 345 | 1100 | 93,143 | 50,903 | 42,240 |
| WW SOUTH/ EL SOL | 345 | 3000 | 747,292 | 408,393 | 338,899 |
| WW SOUTH/ EL SOL | 345 | 4000 | 639,733 | 349,612 | 290,121 |
| WW SOUTH/ EL SOL | 345 | 2500 | 508,754 | 278,032 | 230,722 |
| WW SOUTH/ EL SOL | 345 | 400 | 513,795 | 280,787 | 233,008 |
| WW SOUTH/ EL SOL | 345 | 7900 | 182,292 | 99,622 | 82,670 |
| WW SOUTH/ EL SOL | 345 | 8600 | 310,706 | 169,800 | 140,906 |
| WW SOUTH/ EL SOL | 345 | 9200 | 165,160 | 90,259 | 74,901 |
| WW SOUTH/ EL SOL | 345 | 4400 | 303,373 | 165,793 | 137,580 |
| WW VAIL/SOUTH | 345 | 3000 | 308,782 | 168,749 | 140,033 |
| WW VAIL/SOUTH | 345 | 2000 | 223,601 | 122,197 | 101,404 |
| WW WESTWING SUB | 345 | 1100 | 14,150 | 8,075 | 6,075 |
| OTHER | | | 0 | 0 | 0 |
| TOTAL 354 | | | 8,190,835 | 4,393,133 | 3,797,702 |

## Schedule 1 to the Restructuring Agreement

Transmission Line Detail
(as of 6/30/2000)

RUS 355--POLES & FIXTURES - PLANT

| | VOLT LEVEL | TAX DIST | RUS 101 | RUS 106 | TOTAL | Actual Depr | Book Value |
|---|---|---|---|---|---|---|---|
| 3 POINTS/MARANA | 115 | 4000 | 29,785 | | 29,785 | 27,094 | 2,691 |
| 3 POINTS/MARANA | 115 | 5100 | 968 | | 968 | 846 | 122 |
| 3 POINTS/MARANA | 115 | 604 | 18,785 | 5,109 | 23,894 | 16,847 | 7,047 |
| 3 POINTS/MARANA | 115 | 600 | 20,532 | | 20,532 | 17,935 | 2,597 |
| 3 POINTS/MARANA | 115 | 5101 | 11,264 | | 11,264 | 9,839 | 1,425 |
| 3 POINTS/MARANA | 115 | 601 | 32,233 | 6,158 | 38,391 | 28,711 | 9,680 |
| 3 POINTS/TWIN BUTTES | 115 | 5101 | 756 | | 756 | 558 | 198 |
| 3 POINTS/TWIN BUTTES | 115 | 3000 | 945 | | 945 | 698 | 247 |
| APACHE SUB 69KV TIE | 69 | 2600 | 2,043 | 4,506 | 6,549 | 2,366 | 4,183 |
| APACHE/BUTTERFIELD | 230 | 2200 | 94,348 | | 94,348 | 193 | 94,155 |
| APACHE/BUTTERFIELD | 230 | 900 | 333,060 | | 333,060 | 86,008 | 247,052 |
| APACHE/BUTTERFIELD | 230 | 2600 | 81,397 | 18,444 | 99,841 | 21,020 | 78,821 |
| APACHE/HAYDEN | 115 | 4160 | 45,799 | | 45,799 | 39,331 | 6,468 |
| APACHE/HAYDEN | 115 | 200 | 33,564 | | 33,564 | 28,824 | 4,740 |
| APACHE/HAYDEN | 115 | 803 | 216,848 | | 216,848 | 186,225 | 30,623 |
| APACHE/HAYDEN | 115 | 300 | 156,634 | 110,852 | 267,486 | 140,884 | 126,602 |
| APACHE/HAYDEN | 115 | 4400 | 100,654 | | 100,654 | 86,439 | 14,215 |
| APACHE/HAYDEN | 115 | | | 27,446 | 27,446 | 3,132 | 24,314 |
| APACHE/HAYDEN | 115 | 900 | 107,844 | 9,771 | 117,615 | 94,199 | 23,416 |
| APACHE/HAYDEN | 115 | 2600 | 79,311 | 6,382 | 85,693 | 69,145 | 16,548 |
| APACHE/HAYDEN | 115 | 4100 | 43,261 | 10,486 | 53,747 | 38,852 | 14,895 |
| APACHE/HAYDEN | 115 | 2000 | 0 | 7,978 | 7,978 | 719 | 7,259 |
| APACHE/REDTAIL | 230 | 1300 | 584,820 | | 584,820 | 305,554 | 279,266 |
| APACHE/REDTAIL | 230 | 2600 | 112,669 | | 112,669 | 58,867 | 53,802 |
| BICK SUB TIE (3 PNTS) | 115 | 3000 | 2,298 | | 2,298 | 1,366 | 932 |
| BUTTERFIELD/SAN RAFA | 230 | 2100 | 701,630 | | 701,630 | 181,185 | 520,445 |
| BUTTERFIELD/SAN RAFA | 230 | 900 | 186,163 | | 186,163 | 48,073 | 138,090 |
| BUTTERFIELD/SAN RAFA | 230 | 4900 | 325,166 | | 325,166 | 83,969 | 241,197 |
| BUTTERFIELD/SAN RAFA | 230 | 6830 | 370,130 | | 370,130 | 95,581 | 274,549 |
| BUTTERFIELD/SAN RAFA | 230 | 100 | 1,041,784 | | 1,041,784 | 269,025 | 772,759 |
| BUTTERFIELD/SAN RAFA | 230 | 6800 | 570,558 | | 570,558 | 147,338 | 423,220 |
| BUTTERFIELD/PANTANO | 230 | 2000 | 267,493 | 3,250 | 270,743 | 165,461 | 105,282 |
| BUTTERFIELD/PANTANO | 230 | 6400 | 178,048 | 20,056 | 198,104 | 110,134 | 87,970 |
| BUTTERFIELD/PANTANO | 230 | 900 | 487,082 | 71,130 | 558,212 | 301,291 | 256,921 |
| DAVIS DAM/BIG BEND R/ | 230 | 1579 | 2,953 | | 2,953 | 1,259 | 1,694 |
| DAVIS DAM/BIG BEND | 230 | 1579 | 196,627 | | 196,627 | 83,840 | 112,787 |
| DAVIS DAM/BIG BEND | 230 | 1570 | 372,584 | | 372,584 | 158,866 | 213,718 |
| DAVIS DAM/BIG BEND | 230 | 1579 | 86,551 | | 86,551 | 36,905 | 49,646 |
| DAVIS DAM/RIVIERA | 230 | 1579 | 315,677 | | 315,677 | 119,435 | 196,242 |
| DAVIS DAM/RIVIERA | 230 | 1570 | 646,599 | 567,924 | 1,214,523 | 273,281 | 941,242 |
| DAVIS DAM/RIVIERA | 230 | 1579 | 34,096 | | 34,096 | 12,900 | 21,196 |
| GREENLEE SUB TIE | 345 | 230 | 3,597 | 248,658 | 252,255 | 1,879 | 250,376 |
| GREENLEE SUB TIE | 345 | 200 | 161,854 | | 161,854 | 84,565 | 77,289 |
| GREENLEE SUB TIE ROA | 345 | 200 | 1,686 | | 1,686 | 881 | 805 |
| GREENLEE/MORENCI | 230 | 310 | 57,621 | | 57,621 | 30,106 | 27,515 |
| GREENLEE/MORENCI | 230 | 300 | 177,006 | | 177,006 | 92,482 | 84,524 |
| GREENLEE/MORENCI | 230 | 200 | 50,842 | | 50,842 | 26,564 | 24,278 |
| GREENLEE/MORENCI RD | 230 | 300 | 6,937 | | 6,937 | 3,624 | 3,313 |
| GREENLEE/MORENCI RD | 230 | 310 | 1,087 | | 1,087 | 568 | 519 |
| GREENLEE/MORENCI RD | 230 | 200 | 845 | | 845 | 441 | 404 |
| HACKBERRY/DOS COND | 230 | 500 | 247,991 | | 247,991 | 123,612 | 124,379 |
| HACKBERRY/DOS COND | 230 | 570 | 14,176 | 10,400 | 24,576 | 7,504 | 17,072 |
| HACKBERRY/DOS COND | 230 | 570 | 173,287 | 220,520 | 393,807 | 90,348 | 303,459 |
| HACKBERRY/DOS COND | 230 | 500 | 3,327 | | 3,327 | 1,658 | 1,669 |
| MARANA SUB TAP | 115 | 604 | 2,829 | | 2,829 | 2,471 | 358 |
| MORENCI/HACKBERRY R | 230 | 500 | 3,486 | | 3,486 | 1,821 | 1,665 |
| MORENCI/HACKBERRY R | 230 | 200 | 9,503 | | 9,503 | 4,965 | 4,538 |
| MORENCI/HACKBERRY | 230 | 570 | 443,686 | | 443,686 | 231,815 | 211,871 |
| MORENCI/HACKBERRY | 230 | 500 | 621,846 | 192,923 | 814,769 | 329,571 | 485,198 |
| MORENCI/HACKBERRY | 230 | 310 | 42,298 | | 42,298 | 22,099 | 20,199 |
| MORENCI/HACKBERRY | 230 | 200 | 395,094 | | 395,094 | 206,427 | 188,667 |
| MORENCI/MOR MINE | 230 | 1810 | 108,129 | | 108,129 | 56,495 | 51,634 |
| MORENCI/MOR MINE RD | 230 | 310 | 401 | | 401 | 210 | 191 |
| MORENCI/MOR MINE RD | 230 | 1810 | 1,698 | | 1,698 | 887 | 811 |
| MORENCI/MORENCI | 230 | 310 | 54,006 | | 54,006 | 28,217 | 25,789 |
| MORENCI/MORENCI | 230 | 300 | 123,209 | | 123,209 | 64,373 | 58,836 |
| MORENCI/MOR MINE RD | 230 | 1800 | 40 | | 40 | 21 | 19 |

## Schedule 1 to the Restructuring Agreement

Transmission Line Detail
(as of 6/30/2000)

RUS 355--POLES & FIXTURES - (continued)

| | VOLT LEVEL | TAX DIST | RUS 101 | RUS 106 | TOTAL | Depr | Book Value |
|---|---|---|---|---|---|---|---|
| MORENCI/MOR MINE RD | 230 | 300 | 435 | | 435 | 227 | 208 |
| MORENCI/MOR MINE | 230 | 1800 | 139,532 | 29,001 | 168,533 | 75,514 | 93,019 |
| PANTANO/BICKNELL | 230 | 2000 | 132,643 | | 132,643 | 82,048 | 50,595 |
| PANTANO/BICKNELL | 230 | 2000 | 341,860 | | 341,860 | 211,462 | 130,398 |
| PANTANO/BICKNELL | 230 | 3000 | 563,018 | 64,607 | 627,625 | 349,673 | 277,952 |
| PANTANO/KARTCHNER | 115 | 100 | 27,904 | | 27,904 | 17,261 | 10,643 |
| PANTANO/KARTCHNER | 115 | 2000 | 97,819 | | 97,819 | 60,507 | 37,312 |
| PANTANO/KARTCHNER | 115 | 3700 | 316,662 | | 316,662 | 195,875 | 120,787 |
| PANTANO/KARTCHNER | 115 | 6930 | 183,546 | 20,124 | 203,670 | 115,217 | 88,453 |
| PANTANO/KARTCHNER | 115 | 2500 | 65,137 | | 65,137 | 40,291 | 24,846 |
| PARKER/BAGDAD RD | 69 | 2000 | 2,773 | | 2,773 | 2,422 | 351 |
| PARKER/BAGDAD | 69 | 2000 | 41,862 | 149,848 | 191,710 | 72,505 | 119,205 |
| PARKER/BAGDAD | 69 | 600 | 816,526 | 219,556 | 1,036,082 | 757,275 | 278,807 |
| PARKER/BAGDAD RD | 69 | 600 | 14,915 | | 14,915 | 13,029 | 1,886 |
| REDTAIL/DOS COND | 230 | 100 | 312,378 | | 312,378 | 163,210 | 149,168 |
| REDTAIL/DOS COND | 230 | 500 | 318,379 | | 318,379 | 166,345 | 152,034 |
| REDTAIL/DOS COND | 230 | 1300 | 85,643 | | 85,643 | 44,746 | 40,897 |
| REDTAIL/DOS COND RD | 230 | 100 | 396 | | 396 | 207 | 189 |
| REDTAIL/DOS COND | 230 | 1400 | 145,363 | | 145,363 | 75,948 | 69,415 |
| REDTAIL/DOS COND RD | 230 | 500 | 13,816 | | 13,816 | 7,219 | 6,597 |
| ROMNEY SUB TIE | 69 | 230 | 6,175 | | 6,175 | 3,820 | 2,355 |
| 3 POINTS/BICK R/W | 115 | 5101 | 2,690 | | 2,690 | 1,987 | 703 |
| 3 POINTS/BICK R/W | 115 | 5100 | 5,561 | | 5,561 | 4,108 | 1,453 |
| 3 POINTS/BICK R/W | 115 | 3000 | 15,003 | | 15,003 | 11,082 | 3,921 |
| APACHE/HAYDEN R/W | 115 | 803 | 2,961 | | 2,961 | 2,543 | 418 |
| APACHE/HAYDEN R/W | 115 | 4160 | 25 | | 25 | 22 | 3 |
| APACHE/HAYDEN R/W | 115 | 4400 | 1,347 | | 1,347 | 1,157 | 190 |
| APACHE/HAYDEN R/W | 115 | 300 | 5,146 | | 5,146 | 4,419 | 727 |
| APACHE/HAYDEN R/W | 115 | 4100 | 533 | | 533 | 458 | 75 |
| APACHE/HAYDEN R/W | 115 | 2600 | 28,660 | | 28,660 | 24,612 | 4,048 |
| APACHE/HAYDEN R/W | 115 | 200 | 1,226 | | 1,226 | 1,053 | 173 |
| APACHE/HAYDEN R/W | 115 | 900 | 3,974 | | 3,974 | 3,413 | 561 |
| APACHE/REDTAIL R/W | 230 | 2600 | 12,832 | | 12,832 | 6,704 | 6,128 |
| APACHE/REDTAIL R/W | 230 | 1300 | 17,334 | | 17,334 | 9,057 | 8,277 |
| APACHE/ BUTTERFIELD | 230 | 900 | 16,284 | | 16,284 | 4,205 | 12,079 |
| APACHE/ BUTTERFIELD | 230 | 2200 | 10,729 | | 10,729 | 2,771 | 7,958 |
| BUTTERFIELD/PANTANO | 230 | 6400 | 538 | | 538 | 333 | 205 |
| BUTTERFIELD/PANTANO | 230 | 900 | 8,332 | | 8,332 | 5,154 | 3,178 |
| BUTTERFIELD/PANTANO | 230 | 2000 | 860 | | 860 | 532 | 328 |
| BUTTERFIELD/SAN RAFA | 230 | 900 | 80,159 | | 80,159 | 20,700 | 59,459 |
| BUTTERFIELD/SAN RAFA | 230 | 4900 | 46,759 | | 46,759 | 12,075 | 34,684 |
| BUTTERFIELD/SAN RAFA | 230 | 100 | 12,024 | | 12,024 | 3,105 | 8,919 |
| BUTTERFIELD/SAN RAFA | 230 | 6830 | 14,696 | | 14,696 | 3,795 | 10,901 |
| BUTTERFIELD/SAN RAFA | 230 | 2100 | 94,855 | | 94,855 | 24,495 | 70,360 |
| BUTTERFIELD/SAN RAFA | 230 | 6800 | 22,712 | | 22,712 | 5,865 | 16,847 |
| DAVIS DAM/BIG BEND R/ | 69 | 1579 | 12,106 | | 12,106 | 5,162 | 6,944 |
| DAVIS DAM/BIG BEND R/ | 69 | 1570 | 19,783 | | 19,783 | 8,436 | 11,347 |
| GREENLEEE TIE R/W | 345 | 200 | 30,164 | | 30,164 | 15,760 | 14,404 |
| GREENLEE/MORENCI R/ | 230 | 200 | 2,156 | | 2,156 | 1,127 | 1,029 |
| GREENLEE/MORENCI R/ | 230 | 300 | 12,545 | | 12,545 | 6,554 | 5,991 |
| GREENLEE/MORENCI R/ | 230 | 310 | 3,331 | | 3,331 | 1,740 | 1,591 |
| HACK/DOS COND R/W | 230 | 570 | 21,126 | | 21,126 | 10,530 | 10,596 |
| HACK/DOS COND R/W | 230 | 500 | 34,889 | | 34,889 | 17,391 | 17,498 |
| MORENCI/HACK R/W | 230 | 310 | 2,530 | | 2,530 | 1,322 | 1,208 |
| MORENCI/HACK R/W | 230 | 570 | 1,876 | | 1,876 | 980 | 896 |
| MORENCI/HACK R/W | 230 | 500 | 36,713 | | 36,713 | 19,182 | 17,531 |
| MORENCI/MOR MINE R/W | 230 | 310 | 724 | | 724 | 378 | 346 |
| MORENCI/MOR MINE R/W | 230 | 1810 | 1,119 | | 1,119 | 584 | 535 |
| MORENCI/HACK R/W | 230 | 200 | 3,319 | | 3,319 | 12,152 | (8,833) |
| MORENCI/MORENCI R/W | 230 | 1800 | 1,245 | | 1,245 | 651 | 594 |
| MORENCI/MORENCI R/W | 230 | 300 | 1,844 | | 1,844 | 963 | 881 |
| PANTANO/BICKNELL R/W | 230 | 2000 | 11,442 | | 11,442 | 7,077 | 4,365 |
| PANTANO/BICKNELL R/W | 230 | 2000 | 4,477 | | 4,477 | 2,769 | 1,708 |
| PANTANO/BICKNELL R/W | 230 | 3000 | 4,172 | | 4,172 | 2,580 | 1,592 |
| PANTANO/KARTCH R/W | 115 | 2500 | 430 | | 430 | 266 | 164 |
| PANTANO/KARTCH R/W | 115 | 6930 | 318 | | 318 | 197 | 121 |
| PANTANO/KARTCH R/W | 115 | 3700 | 22,647 | | 22,647 | 14,009 | 8,638 |
| PANTANO/KARTCH R/W | 115 | 100 | 3,920 | | 3,920 | 2,425 | 1,495 |

## Schedule 1 to the Restructuring Agreement

Transmission Line Detail
(as of 6/30/2000)

RUS 355–POLES & FIXTURES - (continued)

| | VOLT LEVEL | TAX DIST | RUS 101 | RUS 106 | TOTAL | Depr | Book Value |
|---|---|---|---|---|---|---|---|
| RED TAIL/DOS COND R/W | 230 | 1400 | 7,368 | | 7,368 | 3,850 | 3,518 |
| RED TAIL/DOS COND R/W | 230 | 1300 | 4,124 | | 4,124 | 2,155 | 1,969 |
| RED TAIL/DOS COND R/W | 230 | 100 | 16,523 | | 16,523 | 8,633 | 7,890 |
| RED TAIL/DOS COND R/W | 230 | 500 | 17,243 | | 17,243 | 9,009 | 8,234 |
| VAIL/BICKNELL R/W | 345 | 2050 | 1,322 | | 1,322 | 754 | 568 |
| VAIL/BICKNELL R/W | 345 | 2000 | 1,322 | | 1,322 | 754 | 568 |
| VAIL/BICKNELL R/W | 345 | 3000 | 809,341 | | 809,341 | 461,745 | 347,596 |
| SAN JOSE/ROMNEY | 69 | 200 | 144,696 | | 144,696 | 54,744 | 89,952 |
| SAN JOSE/ROMNEY | 69 | 230 | 3,127 | | 3,127 | 1,183 | 1,944 |
| SAN JOSE/ROMNEY | 69 | 500 | 189,604 | | 189,604 | 71,735 | 117,869 |
| DOS CONDO/ROMNEY | 69 | 500 | 0 | 280,440 | 280,440 | 31,999 | 248,441 |
| DOS CONDO/ROMNEY | 69 | 230 | 0 | 60,159 | 60,159 | 6,864 | 53,295 |
| DOS CONDO/ROMNEY | 69 | 200 | 0 | 82,351 | 82,351 | 9,396 | 72,955 |
| VAIL/BICKNELL | 345 | 3000 | 911,714 | 268,935 | 1,180,649 | 533,553 | 647,096 |
| VAIL/BICKNELL | 345 | 2050 | 99,615 | 228,850 | 328,465 | 60,131 | 268,334 |
| VAIL/BICKNELL | 345 | 2000 | 99,615 | 133,655 | 233,270 | 62,451 | 170,819 |
| BICKNELL/3 POINTS | 115 | | | 639,211 | 639,211 | 88,291 | 550,920 |
| BICKNELL/3 POINTS | 115 | | | 289,423 | 289,423 | 39,977 | 249,446 |
| BICKNELL/3 POINTS | 115 | | | 184,129 | 184,129 | 25,433 | 158,696 |
| 3 POINTS/VALENCIA | 115 | | | 715,925 | 715,925 | 98,888 | 617,037 |
| 3 POINTS/VALENCIA | 115 | | | 603,053 | 603,053 | 83,297 | 519,756 |
| 3 POINTS/AVRA VALLEY | 115 | 5100 | | 73,341 | 73,341 | 246 | 73,095 |
| RS 16 Line | 230 | | | 944,160 | 944,160 | 39,691 | 904,469 |
| LINE TO ASH POND | | | | 113,150 | 113,150 | 12,911 | 100,239 |
| DOS COND/MOR | | | | 14,005 | 14,005 | 1,598 | 12,407 |
| OTHER | | | (11,952) | 5,406 | (6,546) | | (6,546) |
| TOTAL 355 | | | 17,158,000 | 6,661,322 | 23,819,322 | 9,217,762 | 14,601,560 |

RUS 356–OH CONDUCTORS & DEVICES - PLANT

| | VOLT LEVEL | TAX DIST | | | | | |
|---|---|---|---|---|---|---|---|
| 3 POINTS/MARANA | 115 | 5101 | 14,931 | | 14,931 | 13,043 | 1,888 |
| 3 POINTS/MARANA | 115 | 600 | 27,262 | | 27,262 | 23,814 | 3,448 |
| 3 POINTS/MARANA | 115 | 604 | 24,942 | | 24,942 | 21,787 | 3,155 |
| 3 POINTS/MARANA | 115 | 4000 | 39,561 | | 39,561 | 35,974 | 3,587 |
| 3 POINTS/MARANA | 115 | 5100 | 1,310 | | 1,310 | 1,144 | 166 |
| 3 POINTS/MARANA | 115 | 601 | 12,761 | | 12,761 | 11,147 | 1,614 |
| 3 POINTS/TWIN BUTTES | 115 | 5101 | 51,683 | | 51,683 | 38,176 | 13,507 |
| 3 POINTS/TWIN BUTTES | 115 | 3000 | 105,190 | | 105,190 | 77,701 | 27,489 |
| 3 POINTS/TWIN BUTTES | 115 | 5100 | 30,597 | | 30,597 | 22,602 | 7,995 |
| APACHE ST1 | 230 | 2600 | 22,562 | | 22,562 | 13,956 | 8,606 |
| APACHE SUB 69KV | 69 | 2600 | 4,213 | | 4,213 | 1,999 | 2,214 |
| APACHE/BUTTERFIELD | 230 | 900 | 161,967 | 36,306 | 198,273 | 105,202 | 93,071 |
| APACHE/BUTTERFIELD | 230 | 2600 | 17,830 | 4,841 | 22,671 | 5,273 | 17,398 |
| APACHE/BUTTERFIELD | 230 | 2200 | 51,904 | 10,892 | 62,796 | 33,611 | 29,185 |
| APACHE/HAYDEN | 115 | 200 | 43,925 | 113,007 | 156,932 | 47,902 | 109,030 |
| APACHE/HAYDEN | 115 | 2600 | 117,877 | | 117,877 | 101,231 | 16,646 |
| APACHE/HAYDEN | 115 | 4100 | 18,916 | | 18,916 | 16,245 | 2,671 |
| APACHE/HAYDEN | 115 | 803 | 119,408 | | 119,408 | 65,256 | 54,152 |
| APACHE/HAYDEN | 115 | 300 | 132,353 | 38,950 | 171,303 | 117,171 | 54,132 |
| APACHE/HAYDEN | 115 | 900 | 181,943 | | 181,943 | 25,131 | 156,812 |
| APACHE/HAYDEN | 115 | 4400 | 52,794 | 14,268 | 67,062 | 46,623 | 20,439 |
| APACHE/REDTAIL | 230 | 1300 | 744,409 | 27,233 | 771,642 | 392,697 | 378,945 |
| APACHE/REDTAIL | 230 | 2600 | 121,091 | 4,612 | 125,703 | 69,722 | 55,981 |
| APACHE/HAYDEN | 115 | 4160 | 14,279 | | 14,279 | 12,262 | 2,017 |
| BUTTERFIELD/PANTANO | 230 | 6400 | 101,720 | 1,711 | 103,431 | 63,157 | 40,274 |
| BUTTERFIELD/PANTANO | 230 | 2000 | 133,409 | 2,281 | 135,690 | 82,837 | 52,853 |
| BUTTERFIELD/PANTANO | 230 | 900 | 211,350 | 8,341 | 219,691 | 131,885 | 87,806 |
| BUTTERFIELD/SAN RAFA | 230 | 900 | 78,842 | | 78,842 | 20,360 | 58,482 |
| BUTTERFIELD/SAN RAFA | 230 | 100 | 496,522 | | 496,522 | 128,219 | 368,303 |
| BUTTERFIELD/SAN RAFA | 230 | 2100 | 413,386 | | 413,386 | 106,750 | 306,636 |
| BUTTERFIELD/SAN RAFA | 230 | 4900 | | | 0 | 0 | 0 |
| BUTTERFIELD/SAN RAFA | 230 | 6800 | 371,088 | | 371,088 | 135,578 | 235,510 |
| BUTTERFIELD/SAN RAFA | 230 | 6830 | 51,568 | | 51,568 | 13,317 | 38,251 |
| DAVIS DAM SW BICK | 115 | 1579 | 20,047 | | 20,047 | 11,918 | 8,129 |
| DAVIS DAM/BIG BEND | 69 | 1570 | 437,691 | | 437,691 | 186,626 | 251,065 |

## Schedule 1 to the Restructuring Agreement

Transmission Line Detail
(as of 9/30/99)

RUS 356--OH CONDUCTORS & DEVICES - (continued)

| | VOLT LEVEL | TAX DIST | RUS 101 | RUS 106 | TOTAL | Depr | Book Value |
|---|---|---|---|---|---|---|---|
| DAVIS DAM/BIG BEND | 69 | 1579 | 61,636 | | 61,636 | 26,281 | 35,355 |
| DAVIS DAM/BIG BEND | 69 | 1579 | 255,914 | | 255,914 | 109,119 | 146,795 |
| DAVIS/RIVIERA | 230 | 1579 | 27,421 | | 27,421 | 10,375 | 17,046 |
| DAVIS/RIVIERA | 230 | 1579 | 120,089 | 53,462 | 173,551 | 60,314 | 113,237 |
| DAVIS/RIVIERA | 230 | 1570 | 246,484 | | 246,484 | 93,255 | 153,229 |
| GREENLEE TIE LINE | 345 | 200 | 177,902 | | 177,902 | 92,950 | 84,952 |
| GREENLEE/MORENCI | 230 | 200 | 43,886 | | 43,886 | 22,929 | 20,957 |
| GREENLEE/MORENCI | 230 | 310 | 60,363 | | 60,363 | 31,539 | 28,824 |
| GREENLEE/MORENCI | 230 | 300 | 204,401 | | 204,401 | 106,794 | 97,607 |
| HACKBERRY/DOS COND | 230 | 570 | 140,913 | | 140,913 | 70,238 | 70,675 |
| HACKBERRY/DOS COND | 230 | 500 | 235,998 | | 235,998 | 117,634 | 118,364 |
| MARANA SUB ACQ. | 115 | 604 | 4,522 | | 4,522 | 3,950 | 572 |
| MARANA SUB TAP | 115 | 604 | 5,093 | 32,165 | 37,258 | 8,119 | 29,139 |
| MORENCI/HACKBERRY | 230 | 200 | 453,124 | | 453,124 | 236,746 | 216,378 |
| MORENCI/HACKBERRY | 230 | 570 | 35,050 | | 35,050 | 18,313 | 16,737 |
| MORENCI/HACKBERRY | 230 | 500 | 680,516 | | 680,516 | 355,553 | 324,963 |
| MORENCI/HACKBERRY | 230 | 310 | 48,182 | | 48,182 | 25,174 | 23,008 |
| MORENCIMORCENI MINE | 230 | 1810 | 80,830 | | 80,830 | 42,230 | 38,600 |
| MORENCIMORCENI MINE | 230 | 300 | 107,171 | | 107,171 | 62,222 | 44,949 |
| MORENCIMORCENI MINE | 230 | 1800 | 83,433 | | 83,433 | 43,591 | 39,842 |
| MORENCIMORCENI MINE | 230 | 310 | 46,903 | | 46,903 | 24,506 | 22,397 |
| PANTANO/BICKNELL | 230 | 2000 | 72,717 | | 72,717 | 44,980 | 27,737 |
| PANTANO/BICKNELL | 230 | 2000 | 188,083 | | 188,083 | 116,341 | 71,742 |
| PANTANO/BICKNELL | 230 | 3000 | 290,546 | 2,263 | 292,809 | 179,979 | 112,830 |
| PANTANO/KARTCHNER | 115 | 2000 | 11,762 | | 11,762 | 7,276 | 4,486 |
| PANTANO/KARTCHNER | 115 | 2500 | 40,988 | | 40,988 | 22,400 | 18,588 |
| PANTANO/KARTCHNER | 115 | 6930 | 96,559 | 1,168 | 97,727 | 59,861 | 37,866 |
| PANTANO/KARTCHNER | 115 | 100 | 54,781 | | 54,781 | 33,886 | 20,895 |
| PANTANO/KARTCHNER | 115 | 3700 | 175,733 | | 175,733 | 108,702 | 67,031 |
| PANTANO(BICK) CONERP | 69 | 2000 | 21,944 | | 21,944 | 13,574 | 8,370 |
| PARKER//BAGDAD | 69 | 2000 | 3,392 | | 3,392 | 1,935 | 1,457 |
| PARKER//BAGDAD | 69 | 600 | 449,914 | | 449,914 | 393,010 | 56,904 |
| PAR/BAG PLAN RNCH SW | 69 | 600 | 7,844 | | 7,844 | 6,852 | 992 |
| REDTAIL/DOS COND | 230 | 1300 | 103,967 | 2,831 | 106,798 | 54,711 | 52,087 |
| REDTAIL/DOS COND | 230 | 100 | 427,568 | 12,030 | 439,598 | 229,968 | 209,630 |
| REDTAIL/DOS COND | 230 | 1400 | 179,782 | 5,131 | 184,913 | 94,640 | 90,273 |
| REDTAIL/DOS COND | 230 | 500 | 449,218 | 11,854 | 461,072 | 236,343 | 224,729 |
| ROMNEY SUB TIE | 69 | 2873 | 2,873 | | 2,873 | 1,777 | 1,096 |
| SAN JOSE/ROMNEY | 69 | 500 | 48,694 | | 48,694 | 42,535 | 6,159 |
| SAN JOSE/ROMNEY | 69 | 200 | 15,546 | | 15,546 | 13,580 | 1,966 |
| SAN JOSE/ROMNEY | 69 | 230 | 3,546 | | 3,546 | 3,098 | 448 |
| DOS COND/ROMNEY | 69 | 500 | 0 | 22,616 | 22,616 | 2,580 | 20,036 |
| VAIL/BICKNELL | 345 | 2050 | 153,703 | | 153,703 | 95,075 | 58,628 |
| VAIL/BICKNELL | 345 | 2000 | 153,703 | | 153,703 | 87,690 | 66,013 |
| VAIL/BICKNELL | 345 | 3000 | 1,253,592 | 2,977 | 1,256,569 | 715,538 | 541,031 |
| WW EL SOL TO WESTW | 345 | 1100 | 127,346 | | 127,346 | 69,594 | 57,752 |
| WW EL SOL TO WESTW | 345 | 8900 | 102,439 | | 102,439 | 55,982 | 46,457 |
| WW EL SOL TO WESTW | 345 | 1160 | 11,074 | | 11,074 | 6,052 | 5,022 |
| WW SOUTH/EL SOL | 345 | 2800 | 64,946 | | 64,946 | 35,493 | 29,453 |
| WW SOUTH/EL SOL | 345 | 4400 | 85,298 | | 85,298 | 46,615 | 38,683 |
| WW SOUTH/EL SOL | 345 | 7900 | 57,232 | | 57,232 | 31,277 | 25,955 |
| WW SOUTH/EL SOL | 345 | 4000 | 545,524 | | 545,524 | 298,127 | 247,397 |
| WW SOUTH/EL SOL | 345 | 9200 | 41,823 | | 41,823 | 22,857 | 18,966 |
| WW SOUTH/EL SOL | 345 | 8600 | 202,709 | | 202,709 | 110,780 | 91,929 |
| WW SOUTH/EL SOL | 345 | 2000 | 167,875 | | 167,875 | 91,743 | 76,132 |
| WW SOUTH/EL SOL | 345 | 2400 | 415,408 | | 415,408 | 227,020 | 188,388 |
| WW SOUTH/EL SOL | 345 | 6500 | 75,680 | | 75,680 | 41,359 | 34,321 |
| WW SOUTH/EL SOL | 345 | 2500 | 271,037 | | 271,037 | 148,121 | 122,916 |
| WW SOUTH/EL SOL | 345 | 3000 | 380,436 | | 380,436 | 207,907 | 172,529 |
| WW SOUTH/EL SOL | 345 | 400 | 395,547 | | 395,547 | 216,165 | 179,382 |
| WW SOUTH/EL SOL | 345 | 5100 | 407,492 | | 407,492 | 222,693 | 184,799 |
| WW VAIL/SOUTH | 345 | 2000 | 78,093 | | 78,093 | 42,678 | 35,415 |
| WW VAIL/SOUTH | 345 | 3000 | 107,839 | | 107,839 | 58,936 | 48,903 |
| DOS COND/MOR | | 500 | 0 | 4,669 | 4,669 | 533 | 4,136 |
| OTHER | | | (32,386) | (24,004) | (56,390) | | (56,390) |
| TOTAL 356 | | | 15,261,029 | 389,604 | 15,650,633 | 8,242,408 | 7,408,225 |

## Schedule 1 to the Restructuring Agreement

Transmission Line Detail
(as of 9/30/99)

RUS 359--ROADS & TRAILS - PLANT

| | VOLT LEVEL | TAX DIST | RUS 101 | RUS 106 | TOTAL | Depr | Book Value |
|---|---|---|---|---|---|---|---|
| WW ROAD | 345 | 8600 | 8,171 | | 8,171 | 4,465 | 3,706 |
| WW ROAD | 345 | 4400 | 3,438 | | 3,438 | 1,879 | 1,559 |
| WW ROAD | 345 | 6500 | 3,051 | | 3,051 | 1,668 | 1,383 |
| WW ROAD | 345 | 1100 | 1,091 | | 1,091 | 597 | 494 |
| WW ROAD | 345 | 5100 | 16,209 | | 16,209 | 8,858 | 7,351 |
| WW ROAD | 345 | 400 | 15,760 | | 15,760 | 8,613 | 7,147 |
| WW ROAD | 345 | 9200 | 1,686 | | 1,686 | 922 | 764 |
| WW ROAD | 345 | 2000 | 6,767 | | 6,767 | 3,698 | 3,069 |
| WW ROAD | 345 | 4000 | 21,739 | | 21,739 | 11,880 | 9,859 |
| WW ROAD | 345 | 3000 | 15,115 | | 15,115 | 8,260 | 6,855 |
| WW ROAD | 345 | 2500 | 10,925 | 18,485 | 29,410 | 5,971 | 23,439 |
| WW ROAD | 345 | 2800 | 2,618 | | 2,618 | 1,431 | 1,187 |
| WW ROAD | 345 | 7900 | 2,307 | | 2,307 | 1,260 | 1,047 |
| WW ROAD | 345 | 2400 | 16,528 | | 16,528 | 9,032 | 7,496 |
| | | | 125,405 | 18,485 | 143,890 | 68,534 | 75,356 |
| Totals for Lines | | | 32,544,434 | 7,069,411 | 48,945,102 | 21,921,837 | 27,023,265 |
| | | | | | | 21,921,837 | |

## Schedule 1 to the Restructuring Agreement

Transmission Substation Detail
(as of 6/30/2000)

### RUS 350 LAND & LAND RIGHTS

| | TAX DIST | TOTAL | Actual Depr | Book Value |
|---|---|---|---|---|
| WW WESTWING SUB | 1100 | 512 | | 512 |
| MORENCI SUB | 310 | 1,104 | | 1,104 |
| GREENLEE SUB | 230 | 5,241 | | 5,241 |
| DUNCAN SUB | 220 | 375 | | 375 |
| RIVIERA SUB | 1570 | 550 | | 550 |
| ROMNEY SUB | 230 | 145 | | 145 |
| DOS CONADA SUB | 500 | 250 | | 250 |
| BUTTERFIELD SUB | 900 | 1,399 | | 1,399 |
| PANTANO SUB | 2000 | 123 | | 123 |
| REDTAIL | 1300 | 724 | | 724 |
| SAN RAFAEL SUB | 6830 | 5,486 | | 5,486 |
| TOTAL 350 | | 15,909 | | 15,909 |

### RUS 352--STRUCTURES & IMPROVEMENTS - PLANT

| | VOLT LEVE | Total | Actual Depr | Book Value |
|---|---|---|---|---|
| 3 POINTS SUB | 115 | 7,051 | 6,146 | 905 |
| APACHE SUB | 230 | 581,815 | 331,252 | 250,563 |
| BANK 10 SUB | 230 | 27,324 | 20,797 | 6,527 |
| BICKNELL SUB | 345 | 135,395 | 78,958 | 56,437 |
| DOS CONDADO SUB | 230 | 103,894 | 89,038 | 14,856 |
| GREENLEE SUB | 345 | 305,871 | 159,480 | 146,391 |
| KARTCHNER SUB | 115 | 65,206 | 40,251 | 24,955 |
| MARANA SUB | 115 | 6,979 | 6,084 | 895 |
| MORENCI SUB | 230 | 150,872 | 78,664 | 72,208 |
| PANTANO SUB | 230 | 127,563 | 85,748 | 41,815 |
| PANTANO SUB 230 KV | 230 | 11,347 | 6,392 | 4,955 |
| REDTAIL SUB | 230 | 130,060 | 111,463 | 18,597 |
| THATCHER SUB | 69 | 12,249 | 8,148 | 4,101 |
| WW SOUTH SUB | 345 | 130,060 | 74,048 | 56,012 |
| AEPCO/BAGDAD INTER | 69 | 27,673 | 9,785 | 17,888 |
| BUTTERFIELD CLASS 10 | 230 | 122,005 | 31,441 | 90,564 |
| ORACLE SUB | 115 | 2,122 | 496 | 1,626 |
| RIVIERA SUB | 230 | 234,110 | 88,392 | 145,718 |
| ROMNEY SUB | 69 | 51,950 | 32,068 | 19,882 |
| SAN RAFAEL SUB | 230 | 192,989 | 49,733 | 143,256 |
| TOPOCK SUB | | 699,872 | 4,195 | 695,677 |
| OTHER | | (9,725) | 0 | (9,725) |
| TOTAL 352 | | 3,116,682 | 1,312,579 | 1,804,103 |

### RUS 353--STATION EQUIPMENT - PLANT

| | VOLT LEVE | TAX # | RUS 101 | RUS 106 | TOTAL | | |
|---|---|---|---|---|---|---|---|
| 3 POINTS SUB | 230 | 5101 | 192,937 | 18,249 | 211,186 | 169,930 | 41,256 |
| APACHE 115KV SUB | 115 | 2600 | 385,820 | 8,338 | 394,158 | 220,963 | 173,195 |
| APACHE ADD W 2 &3 | 230 | 2600 | 2,571,151 | 41,956 | 2,613,107 | 1,625,722 | 987,385 |
| APACHE IC 3 | 69 | 2600 | 224,917 | | 224,917 | 133,446 | 91,471 |
| APACHE NEW 69 KV | 115 | 2600 | 1,621,547 | | 1,621,547 | 767,727 | 853,820 |
| APACHE ORIG. 115 KV | 69 | 2600 | 207,644 | | 207,644 | 118,220 | 89,424 |
| APACHE ORIG. 69 KV | 69 | 2600 | 241,865 | 9,259 | 251,124 | 212,504 | 38,620 |
| APACHE ST2 | 175 | 2600 | 81,222 | | 81,222 | 40,402 | 40,820 |
| APACHE ST3 | 175 | 2600 | 81,222 | | 81,222 | 40,402 | 40,820 |
| USBR | 69 | 2600 | 907 | | 907 | 516 | 391 |
| BANK 10 SUM | 230 | 1570 | 350,820 | | 350,820 | 267,017 | 83,803 |
| BICKNELL SUB | 345 | 3000 | 2,571,786 | 345,861 | 2,917,647 | 1,572,055 | 1,345,592 |
| BILL WILLIAMS SUB | 69 | 600 | 16,817 | | 16,817 | 14,660 | 2,157 |
| BULLHEAD SUB | 69 | 1570 | 28,529 | | 28,529 | 24,869 | 3,660 |
| DAVIS DAM CONTROL R | 230 | 1570 | 4,862 | | 4,862 | 3,700 | 1,162 |
| DAVIS DAM SUB | 230 | 1570 | 296,359 | 7,525 | 303,884 | 128,178 | 175,706 |
| DOS CONDADOS SUB | 230 | 500 | 1,730,075 | 1,777,800 | 3,507,875 | 1,494,745 | 2,013,130 |
| TUCSON WAPA | 69 | 850 | 6,153 | | 6,153 | 2,323 | 3,830 |
| WAPA SUB | 345 | 200 | 1,924 | | 1,924 | 911 | 1,013 |
| GREENLEE SUB | 345 | 230 | 1,207,274 | 412,768 | 1,620,042 | 659,666 | 960,376 |

## Schedule 1 to the Restructuring Agreement

Transmission Substation Detail
(as of 6/30/2000)

RUS 353--STATION EQUIPMENT - (continued)

| | TAX DIST | | RUS 101 | RUS 106 | TOTAL | Actual Depr | Book Value |
|---|---|---|---|---|---|---|---|
| KARTCH SUB FR SSVEC | 115 | 6930 | see below | | 0 | 0 | 0 |
| KARTCHNER SUB | 115 | 6930 | 801,522 | | 801,522 | 494,769 | 306,753 |
| MARANA SUB | 115 | 604 | 416,362 | 20,467 | 436,829 | 365,282 | 71,547 |
| MARANA SUB ADDITION | 115 | 604 | 301,713 | | 301,713 | 34,355 | 267,358 |
| MORENCI SUB | 230 | 310 | 1,005,838 | 417,530 | 1,423,368 | 563,907 | 859,461 |
| MORTENSEN SUB | 69 | 1600 | 11,979 | | 11,979 | 4,522 | 7,457 |
| NEW THATCHER SUB | 69 | 430 | 10,245 | | 10,245 | 7,798 | 2,447 |
| PANTANO SUB | 230 | 2000 | 583,465 | | 583,465 | 360,165 | 223,300 |
| PANTANO SUB 230 KV | 230 | 2000 | 796,002 | 31,496 | 827,498 | 497,837 | 329,661 |
| REDTAIL SUB | 230 | 1300 | 1,649,223 | 32,836 | 1,682,059 | 1,417,926 | 264,133 |
| RIVER SUB | 230 | 1570 | 28,608 | | 28,608 | 22,460 | 6,148 |
| ROMNEY SUB | 69 | 230 | 712,904 | 5,197 | 718,101 | 355,209 | 362,892 |
| STEWART SUB | 69 | 1300 | 33,255 | | 33,255 | 23,717 | 9,538 |
| SAHUARITA TEMP | 69 | 3000 | 33,247 | 25,890 | 59,137 | 1,160 | 57,977 |
| SAHUARITA | | 3000 | 0 | 2,392,740 | 2,392,740 | 32,323 | 2,360,417 |
| THATCHER SUB | 69 | 440 | 157,492 | 18,476 | 175,968 | 107,316 | 68,652 |
| WW SOUTH SUB | 345 | 1000 | 718,981 | | 718,981 | 392,110 | 326,871 |
| WW VAIL SUB INTERCO | 345 | 2000 | 118,164 | | 118,164 | 67,276 | 50,888 |
| WW VAIL SUB TAP | 345 | 2050 | 1,101,654 | 15,529 | 1,117,183 | 628,986 | 488,197 |
| WW WEWSTWING SUB | 345 | 1100 | 936,569 | | 936,569 | 533,229 | 403,340 |
| AEPCO/BAGDAD INTER | 69 | 2000 | 77,860 | | 77,860 | 27,531 | 50,329 |
| TONY LAPPOS ANZA RE | 35 | 0 | 151,952 | 54,861 | 206,813 | 28,205 | 178,608 |
| BAGDAD | 69 | 2000 | 6,153 | | 6,153 | 2,323 | 3,830 |
| BIG BEND SUB | 69 | 1570 | 7,017 | | 7,017 | 2,481 | 4,536 |
| BUTTERFIELD CLASS 10 | 230 | 900 | 1,212,715 | | 1,212,715 | 312,520 | 900,195 |
| CY/BAGDAD PWR FACT | 69 | 600 | 7,876 | | 7,876 | 2,973 | 4,903 |
| HAWES SUB | 69 | 6870 | 5,757 | | 5,757 | 2,035 | 3,722 |
| KINGMAN | 69 | 400 | 14,002 | | 14,002 | 5,287 | 8,715 |
| MTN CENTER ANZA SUB | 35 | 0 | 7,105 | | 7,105 | 2,682 | 4,423 |
| ORACLE SUB | 115 | 200 | 139,641 | 45,300 | 184,941 | 32,638 | 152,303 |
| RIVIERA SUB | 230 | 1570 | 2,372,053 | 17,533 | 2,389,586 | 897,598 | 1,491,988 |
| 2ND RIVIERA XFORMER | 230 | 1570 | 1,321,900 | | 1,321,900 | 150,523 | 1,171,377 |
| ROUND VALLEY | 230 | 800 | 13,853 | | 13,853 | 5,230 | 8,623 |
| SAFFORS SUB METERIN | 69 | 150 | 16,332 | | 16,332 | 2,251 | 14,081 |
| SAV JOSE SUB | 69 | 570 | 21,232 | | 21,232 | 8,016 | 13,216 |
| SAN RAFAEL SUB | 230 | 6830 | 2,139,342 | | 2,139,342 | 493,748 | 1,645,594 |
| TOMBSTONE JUNCTION | 69 | 100 | 5,757 | | 5,757 | 2,035 | 3,722 |
| VALENCIA SUB | 115 | 102 | | 1,176,658 | 1,176,658 | 162,191 | 1,014,467 |
| 3 POINTS SUB EXPAN. | 115 | 5105 | | 1,049,612 | 1,049,612 | 144,679 | 904,933 |
| AVRA VALLEY SUB | 115 | 604 | | 1,462,022 | 1,462,022 | 132,569 | 1,329,453 |
| TOPOCK SUB | 230 | | | 2,175,816 | 2,175,816 | 39,119 | 2,136,697 |
| OTHER | | | 3,477 | (3,477) | 0 | | 0 |
| TOTAL 353 | | | 28,765,078 | 11,560,242 | 40,325,320 | 15,864,937 | 24,460,383 |
| Total for Substations | | | 28,765,078 | 11,560,242 | 43,457,911 | 17,177,516 | 26,280,395 |
| | | | | | | 17,177,516 | |

## Schedule 1 to the Restructuring Agreement

Communication Equipment
(as of 6/30/00)

| Microwave Equipment | RUS 389 | RUS 390 | RUS 397 | Total Plant | Actual Depr | Book Value |
|---|---|---|---|---|---|---|
| Apache | | | 58,143 | 58,143 | 45,383 | 12,760 |
| Bagdad Wellfield | | 8,425 | 88,227 | 96,652 | 75,440 | 21,212 |
| Benson | | | 416,834 | 416,834 | 325,354 | 91,480 |
| Bicknell | | | 19,249 | 19,249 | 15,025 | 4,224 |
| Bill Williams | | 5,265 | 53,378 | 58,643 | 45,773 | 12,870 |
| Bullhead | | 6,444 | 48,877 | 55,321 | 43,180 | 12,141 |
| Butterfield | | | 41,783 | 41,783 | 32,613 | 9,170 |
| Confidence Peak | | 42,692 | 0 | 42,692 | 33,323 | 9,369 |
| Coolidge | | | 0 | 0 | 0 | 0 |
| Davis Dam | | | 78,470 | 78,470 | 61,249 | 17,221 |
| Dos Cabazos | | | 7,390 | 7,390 | 5,768 | 1,622 |
| Dos Condado | 1,260 | | 6,618 | 7,878 | 6,149 | 1,729 |
| Duncan Valley | | | 0 | 0 | 0 | 0 |
| Greenlee | | | 785 | 785 | 613 | 172 |
| Guthrie | 350 | | 8,047 | 8,397 | 6,554 | 1,843 |
| Helmet Peak | | 37,355 | 0 | 37,355 | 29,157 | 8,198 |
| Hidden Valley | | 84,544 | 0 | 84,544 | 65,990 | 18,554 |
| Hualpai | | | 293,303 | 293,303 | 228,934 | 64,369 |
| Irvington | | | 0 | 0 | 0 | 0 |
| Karchner | | | 9,135 | 9,135 | 7,130 | 2,005 |
| Kingman | | 5,826 | 64,167 | 69,993 | 54,632 | 15,361 |
| Marana | | | 7,866 | 7,866 | 6,140 | 1,726 |
| Mesa | | | 0 | 0 | 0 | 0 |
| Morenci | | | 4,800 | 4,800 | 3,747 | 1,053 |
| Mortensen | | | 23,082 | 23,082 | 18,016 | 5,066 |
| Oracle | | | 30,792 | 30,792 | 24,034 | 6,758 |
| Pantano | | | 3,315 | 3,315 | 2,587 | 728 |
| Pinal Peak | 77 | | 19,541 | 19,618 | 15,313 | 4,305 |
| Pistol Hill | 260 | | 5,871 | 6,131 | 4,785 | 1,346 |
| Redtail | | | 8,633 | 8,633 | 6,738 | 1,895 |
| Rivera | | | 81,503 | 81,503 | 63,616 | 17,887 |
| Romney | | | 0 | 0 | 0 | 0 |
| Round Valley | | | 64,125 | 64,125 | 50,052 | 14,073 |
| San Jose | | | 33,032 | 33,032 | 25,783 | 7,249 |
| San Rafeal | | | 57,892 | 57,892 | 45,187 | 12,705 |
| San Xavier | 1,110 | 11,576 | 71,523 | 84,209 | 65,728 | 18,481 |
| South Sub | | | 0 | 0 | 0 | 0 |
| Stewart | | | 3,443 | 3,443 | 2,687 | 756 |
| Texas Canyon | 370 | | 158,430 | 158,800 | 123,949 | 34,851 |
| Thatcher | | | 56,388 | 56,388 | 44,013 | 12,375 |
| Three Points | | | 2,006 | 2,006 | 1,566 | 440 |
| Tombstone | | | 0 | 0 | 0 | 0 |
| Trico | | | 8,835 | 8,835 | 6,896 | 1,939 |
| Tucson Sub WAPA Tap | | | 4,525 | 4,525 | 3,532 | 993 |
| Vail | | | 6,267 | 6,267 | 4,892 | 1,375 |
| WAPA | | | 50,400 | 50,400 | 39,339 | 11,061 |
| Westwing | | | 0 | 0 | 0 | 0 |
| White Tanks | | 114,004 | 0 | 114,004 | 88,984 | 25,020 |
| Wilcox | | | 6,295 | 6,295 | 4,913 | 1,382 |
| | 3,427 | 316,131 | 1,902,970 | 2,222,528 | 1,734,765 | 487,763 |

| CDC Equipment | | | | | | |
|---|---|---|---|---|---|---|
| Anza | | | 7,480 | 7,480 | 5,838 | 1,642 |
| Apache | | | 44,023 | 44,023 | 34,362 | 9,661 |
| Benson | | | 0 | 0 | 0 | 0 |
| Bicknell | | | 17,095 | 17,095 | 13,343 | 3,752 |
| Bullhead | | | 9,970 | 9,970 | 7,782 | 2,188 |
| Butterfield | | | 32,297 | 32,297 | 25,209 | 7,088 |
| Davis Dam | | | 54,973 | 54,973 | 42,908 | 12,065 |
| Dos Condado | | | 8,976 | 8,976 | 7,006 | 1,970 |
| Greenlee | | | 9,743 | 9,743 | 7,605 | 2,138 |

## Schedule 1 to the Restructuring Agreement

Communication Equipment
(as of 6/30/00)

| CDC Equipment (continued) | RUS 389 | RUS 390 | RUS 397 | Total Plant | Actual Depr | Book Value |
|---|---|---|---|---|---|---|
| Hayden | | | 6,640 | 6,640 | 5,183 | 1,457 |
| Kartchner | | | 8,258 | 8,258 | 6,446 | 1,812 |
| Kingman | | | 9,930 | 9,930 | 7,751 | 2,179 |
| Marana | | | 7,662 | 7,662 | 5,980 | 1,682 |
| Morenci | | | 8,058 | 8,058 | 6,290 | 1,768 |
| Oracle | | | 21,781 | 21,781 | 17,001 | 4,780 |
| Pantano | | | 7,456 | 7,456 | 5,820 | 1,636 |
| Redtail | | | 36,489 | 36,489 | 28,481 | 8,008 |
| Riviera | | | 17,020 | 17,020 | 13,285 | 3,735 |
| Romney | | | 7,959 | 7,959 | 6,212 | 1,747 |
| Round Valley | | | 7,676 | 7,676 | 5,991 | 1,685 |
| San Rafael | | | 34,671 | 34,671 | 27,062 | 7,609 |
| Stewart | | | 6,587 | 6,587 | 5,141 | 1,446 |
| Thatcher | | | 7,802 | 7,802 | 6,090 | 1,712 |
| Three Points | | | 6,924 | 6,924 | 5,404 | 1,520 |
| Tombstone | | | 6,871 | 6,871 | 5,363 | 1,508 |
| Tucson Sub WAPA | | | 7,235 | 7,235 | 5,647 | 1,588 |
| Vail | | | 6,336 | 6,336 | 4,945 | 1,391 |
| Wellfield | | | 12,746 | 12,746 | 9,949 | 2,797 |
| Williams | | | 7,847 | 7,847 | 6,125 | 1,722 |
| | | | 420,505 | 420,505 | 328,220 | 92,285 |
| **Common Equipment** | | | | | | |
| Anza | | | 0 | 0 | 0 | 0 |
| Apache | | | 370,048 | 370,048 | 288,836 | 81,212 |
| Benson | | | 256,970 | 256,970 | 200,575 | 56,395 |
| Greenlee | | | 0 | 0 | 0 | 0 |
| Guthrie | | | 0 | 0 | 0 | 0 |
| Mohave | | | 23,084 | 23,084 | 18,018 | 5,066 |
| Safety Bldg | | | 5,541 | 5,541 | 4,325 | 1,216 |
| Smith Peak | | | 24,451 | 24,451 | 19,085 | 5,366 |
| Trico | | | 3,315 | 3,315 | 2,587 | 728 |
| Vail | | | 0 | 0 | 0 | 0 |
| WAPA | | | 1,654 | 1,654 | 1,291 | 363 |
| | | | 685,063 | 685,063 | 534,717 | 150,346 |
| Total | 3,427 | 316,131 | 3,008,538 | 3,328,096 | 2,597,701 | 730,395 |
| | | | | | 2,597,701 | |
| Energy Management System - 12/97 Addition | | | 3,725,150 | 3,725,150 | 564,442 | 3,160,708 |
| Energy Management System - 11/99 Addition | | | 2,340,812 | 2,340,812 | 70,934 | 2,269,878 |
| Microwave Upgrades - 11/99 Addition | | | 2,052,251 | 2,052,251 | 62,189 | 1,990,062 |
| Grand Total | 3,427 | 316,131 | 11,126,751 | 11,446,309 | 3,295,266 | 8,151,043 |

**Arizona Electric Power Cooperative**
Non Generation Assets - RUS 392
TRANSCO
as of June 30, 2000



| Description | Item # | VEH # | Date Acquired | Orig. Book Value | RUS | FCN | COUNTY | TAX DIST | Quantity |
|---|---|---|---|---|---|---|---|---|---|
| Plnt-Transportation Equip | | | | | | | | | |
| MACK TANK TRUCK | 936 | 11002 | 02/28/90 | 16,478 | 392 | TRN | 2 | 980 | 1 |
| CHANCE HOTLINE TRL | 939 | 11007 | 08/31/82 | 11,218 | 392 | TRN | 2 | 980 | 1 |
| 1971 HOTLINE TRL | 940 | 11012 | 03/31/74 | 650 | 392 | TRN | 2 | 980 | 1 |
| 1980 HOTLINE TRL | 945 | 11034 | 07/31/81 | 12,465 | 392 | TRN | 2 | 980 | 1 |
| TANK SEMI-TRAILER | 947 | 11044 | 07/31/77 | 7,020 | 392 | TRN | 2 | 980 | 1 |
| 1986 GMC PU 7000 | 954 | 11063 | 04/30/88 | 11,718 | 392 | TRN | 2 | 980 | 1 |
| 1968 WATER TRAILER | 961 | 11091 | 12/31/90 | 1,575 | 392 | TRN | 2 | 980 | 1 |
| 1968 CARGO TRAILER | 963 | 11099 | 11/30/90 | 1,050 | 392 | TRN | 2 | 980 | 1 |
| WELDER W/TRAILER | 964 | 11100 | 12/31/88 | 2,500 | 392 | TRN | 2 | 980 | 1 |
| WEED SPRAYER | 967 | 11108 | 07/31/89 | 4,883 | 392 | TRN | 2 | 980 | 1 |
| GMC VP JIMMY | 980 | 11127 | 06/30/91 | 18,223 | 392 | TRN | 2 | 980 | 1 |
| KALYN POLE TRAILER | 983 | 11131 | 07/31/91 | 19,149 | 392 | TRN | 2 | 980 | 1 |
| LOWBOY TRAILER | 986 | 11136 | 09/30/91 | 9,450 | 392 | TRN | 2 | 980 | 1 |
| MACK TRUCK | 988 | 11140 | 02/29/92 | 100,074 | 392 | TRN | 2 | 980 | 1 |
| ECONLINE TRAILER 6T | 990 | 11142 | 02/29/92 | 3,098 | 392 | TRN | 2 | 980 | 1 |
| ECONLINE TRAILER 6T | 991 | 11143 | 02/29/92 | 3,098 | 392 | TRN | 2 | 980 | 1 |
| 92 CHEVY PU | 997 | 11152 | 06/30/92 | 17,221 | 392 | TRN | 2 | 980 | 1 |
| 92 CHEVY BLAZER | 1001 | 11157 | 07/31/92 | 20,555 | 392 | TRN | 2 | 980 | 1 |
| STELLER SYS ON 63 | 1002 | 11158 | 07/31/92 | 36,142 | 392 | TRN | 2 | 980 | 1 |
| 92 DODGE PU 662953 | 1003 | 11159 | 07/31/92 | 23,201 | 392 | TRN | 2 | 980 | 1 |
| 93 HOT LINE TRAILE | 1012 | 11170 | 02/28/93 | 4,928 | 392 | TRN | 2 | 980 | 1 |
| 93 GMC 1/2T PU | 1017 | 11176 | 05/31/93 | 24,533 | 392 | TRN | 2 | 980 | 1 |
| JOHN DEERE GATOR | 1020 | 11179 | 08/31/93 | 5,702 | 392 | TRN | 2 | 980 | 1 |
| 95 FORD BRONCO | 1029 | 11191 | 07/31/95 | 22,721 | 392 | TRN | 2 | 980 | 1 |
| 95 FORD F250 4X2 | 1030 | 11192 | 11/30/95 | 26,957 | 392 | TRN | 2 | 980 | 1 |
| 95 FORD F250 4X4 | 1032 | 11194 | 12/31/95 | 39,171 | 392 | TRN | 2 | 980 | 1 |
| FORD F350 4X4 | 1033 | 11195 | 11/30/95 | 28,545 | 392 | TRN | 2 | 980 | 1 |
| 95 CHEVY CARGO VAN | 1034 | 11196 | 10/31/95 | 20,236 | 392 | TRN | 2 | 980 | 1 |
| 97 FORD F250 TRUCK | 1039 | 11201 | 12/04/96 | 27,619 | 392 | TRN | 2 | 980 | 1 |
| 97 CHEV VAN | 1043 | 11205 | 04/30/97 | 19,791 | 392 | TRN | 2 | 980 | 1 |
| 97 DODGE RAM TRUCK | 1046 | 11208 | 12/17/96 | 28,172 | 392 | TRN | 2 | 980 | 1 |

**Arizona Electric Power Cooperative**
Non Generation Assets - RUS 392
TRANSCO
as of June 30, 2000



| Description | Item # | VEH # | Date Acquired | Orig. Book Value | RUS | FCN | COUNTY | TAX DIST | Quantity |
|---|---|---|---|---|---|---|---|---|---|
| Plnt-Transportation Equip | | | | | | | | | |
| 97 DODGE RAM TRUCK | 1047 | 11209 | 12/17/96 | 28,172 | 392 | TRN | 2 | 980 | 1 |
| 97 FORD TRUCK | 1051 | 11214 | 06/30/97 | 26,980 | 392 | TRN | 2 | 980 | 1 |
| 97 FORD EXPLORER | 1127 | 11221 | 12/16/97 | 24,177 | 392 | TRN | 2 | 980 | 1 |
| Service Body & Wench | 1151 | 11224 | 07/01/98 | 2,077 | 392 | TRN | 2 | 980 | 1 |
| Truck, 98 GM 1/2 Ton P/U | 1159 | 11226 | 07/31/98 | 22,658 | 392 | TRN | 2 | 980 | 1 |
| Truck, 98 GM 3/4 Ton P/U | 1160 | 11224 | 07/31/98 | 22,422 | 392 | TRN | 2 | 980 | 1 |
| Trailer,20 Ton PILT,DYNA | 1175 | 11228 | 08/31/98 | 14,384 | 392 | TRN | 2 | 980 | 1 |
| SUV, 98 Ford Explorer | 1288 | 11234 | 01/31/99 | 21,395 | 392 | TRN | 2 | 980 | 1 |
| Versalift 24 Bucket (Aerial | 1367 | 11246 | 07/31/88 | 9,568 | 392 | TRN | 2 | 980 | 1 |
| 99 1 Ton Truck Chevy 4 x 4 | 1374 | 11236 | 06/30/99 | 23,069 | 392 | TRN | 2 | 980 | 1 |
| 99 1 Ton Truck Chevy 4 x 4 | 1375 | 11242 | 06/30/99 | 23,069 | 392 | TRN | 2 | 980 | 1 |
| Service Body & Winch | 1376 | 11236 | 08/30/92 | 5,192 | 392 | TRN | 2 | 980 | 1 |
| Service Body & Winch | 1377 | 11242 | 05/31/93 | 5,192 | 392 | TRN | 2 | 980 | 1 |
| 99 Chevy Tahoe 4x4 (ROW) | 1401 | 11238 | 07/31/99 | 30,367 | 392 | TRN | 2 | 980 | 1 |
| 99 Chevy 3/4 Ton 4x4 Truck | 1402 | 11239 | 07/31/99 | 27,173 | 392 | TRN | 2 | 980 | 1 |
| 99 SUV Ford Explorer (B Ril | 1593 | 11257 | 03/31/00 | 23,107 | 392 | TRN | 2 | 980 | 1 |
| 2000 Chevy 1/2 ton Truck | 1603 | 11258 | 04/30/00 | 27,234 | 392 | TRN | 2 | 980 | 1 |
| 2000 Chevy 3/4 ton Cargo V | 1612 | 11254 | 06/30/00 | 20,152 | 392 | TRN | 2 | 980 | 1 |
| 2000 Chevy 1 ton Truck | 1614 | 11252 | 06/30/00 | 20,152 | 392 | TRN | 2 | 980 | 1 |
| 2000 Chevy 1 ton Truck | 1615 | 11253 | 06/30/00 | 20,152 | 392 | TRN | 2 | 980 | 1 |
| PRESSURE WASHER | 999 | 11155 | 09/30/92 | 61,715 | 392 | TRN | 2 | 2600 | 1 |
| Total Transportation Equipment | | | | 1,026,550 | | | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 393
TRANSCO
As of June 30, 2000



| Description | Item # | Date Acquired | Orig. Book Value | RUS | FCN | County | TAX DIST |
|---|---|---|---|---|---|---|---|
| BENSON | 753 | 01/01/80 | 19,288 | 393 | AG | 2 | 980 |
| Total Stores Equip | | | 19,288 | | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 394
TRANSCO
As of June 30, 2000



| Description | Item # | Date Acquired | Orig. Book Value | RUS | FCN | County | TAX DIST |
|---|---|---|---|---|---|---|---|
| Plnt-Tools & Shop Equip | | | | | | | |
| BENSON | 756 | 01/01/80 | 138,210 | 394 | TRN | 2 | 980 |
| Total Tools & Shop Equip | | | 138,210 | | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 395
TRANSCO
As of June 30, 2000



| Description | Item # | Date Acquired | Orig. Book Value | RUS | FCN | County | TAX DIST |
|---|---|---|---|---|---|---|---|
| Plnt-Laboratory Equip | | | | | | | |
| BENSON | 757 | 01/01/80 | 262,641 | 395 | TRN | 2 | 980 |
| Total Laboratory Equip | | | 262,641 | | | | |

**Arizona Electric Power Cooperative**
Non Generation Assets - RUS 396
TRANSCO
as of June 30, 2000



| Description | Item # | VEH # | Date Acquired | Orig. Book Value | RUS | FCN | COUNTY | TAX DIST | Quantity |
|---|---|---|---|---|---|---|---|---|---|
| VAC OIL PURIFIER | 1055 | 12010 | 12/31/73 | 47,292 | 396 | TRN | 2 | 980 | 1 |
| GENERATOR 3#200 | 1056 | 12011 | 03/31/74 | 19,107 | 396 | TRN | 2 | 980 | 1 |
| AUTOCAR AERIAL | 1062 | 12035 | 11/30/81 | 225,938 | 396 | TRN | 2 | 980 | 1 |
| 1982 DIESL TRACTOR | 1067 | 12053 | 05/31/88 | 16,793 | 396 | TRN | 2 | 980 | 1 |
| LOED FORK LIFT | 1071 | 12069 | 04/30/81 | 76,277 | 396 | TRN | 2 | 980 | 1 |
| AUTOCAR DIESEL | 1073 | 12079 | 03/31/83 | 97,592 | 396 | TRN | 2 | 980 | 1 |
| 1986 GREAT DANE TR | 1077 | 12096 | 05/31/86 | 20,471 | 396 | TRN | 2 | 980 | 1 |
| CONDOR AERIAL TRK | 1079 | 12106 | 09/30/89 | 560,703 | 396 | TRN | 2 | 980 | 1 |
| CABLE PULLER | 1080 | 12117 | 03/30/91 | 45,336 | 396 | TRN | 2 | 980 | 1 |
| K MART 45' VAN TRL | 1081 | 12125 | 06/30/91 | 4,120 | 396 | TRN | 2 | 980 | 1 |
| K MART 45' VAN TRL | 1082 | 12126 | 06/30/91 | 4,120 | 396 | TRN | 2 | 980 | 1 |
| HOLE DIGGER(ON 140 | 1084 | 12135 | 10/31/91 | 135,710 | 396 | TRN | 2 | 980 | 1 |
| LINK BLT TRK CRANE | 1085 | 12138 | 02/28/92 | 292,856 | 396 | TRN | 2 | 980 | 1 |
| CASE EXTENDAHOE | 1087 | 12144 | 02/28/92 | 60,295 | 396 | TRN | 2 | 980 | 1 |
| 92 GMC W/BOOM | 1090 | 12167 | 12/31/92 | 69,341 | 396 | TRN | 2 | 980 | 1 |
| 93 MACK TRUCK | 1093 | 12183 | 01/31/94 | 97,469 | 396 | TRN | 2 | 980 | 1 |
| ALTEC BOOM/ELEVATOR | 1125 | 12211 | 09/30/97 | 171,330 | 396 | TRN | 2 | 980 | 1 |
| Trailer (Reel trailer) | 1604 | 11256 | 04/30/00 | 6,300 | 396 | TRN | 2 | 980 | 1 |
| Total Pwr Operation Equip | | | | 1,951,050 | | | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 398
TRANSCO
As of June 30, 2000



| Description | Item # | Date Acquired | Orig. Book Value | RUS | FCN | County | TAX DIST |
|---|---|---|---|---|---|---|---|
| BEN EMERG TOWER - LN | 629 | 01/01/80 | 113,449 | 398 | TRN | 2 | 980 |
| Total Misc Equip | | | 113,449 | | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 399
TRANSCO
As of June 30, 2000



| Description | Item # | Date Acquired | Orig. Book Value | RUS | FCN | County | TAX DIST |
|---|---|---|---|---|---|---|---|
| BENSON | 761 | 01/01/80 | 60,096 | 399 | AG | 2 | 980 |
| DISPATCH POWER SUPPL | 762 | 01/01/80 | 102,720 | 399 | AG | 2 | 980 |
| Total Other Tangible | | | 162,816 | | | | |

1.1060.100 Compl Constr General Plant

| | | | Totals | Transco Portion |
|---|---|---|---|---|
| | Apache Plant Equipment | | | |
| 796 | ST2&3 MODICON CTRL | 314 | 9,230 | |
| 1163 | Hytorc Wrench Turbine | 314 | 27,805 | |
| 1241 | Performance Monitor Upgrad | 314 | 26,993 | |
| 1406 | Portable Boring Machine (t | 314 | 25,000 | |
| 1407 | Turbine Bolting Heaters (t | 314 | 13,500 | |
| | | | 102,528 | |
| | Structures & Improvements | | | |
| 1137 | BARRIER WALL - WEST YARD | 390 | 28,581 | |
| 748 | FIRE ALARM-BLDGS 200 | 390 | 34,628 | |
| 1136 | FUEL SYSTEM AUTOMATION | 390 | 13,456 | |
| 721 | BLDG 2000 REMODEL | 390 | 13,062 | |
| 720 | BEN CABLE MANAGEMENT | 390 | 10,488 | |
| 1500 | Telecom Equip Touchstone B | 390 | 29,950 | |
| 1405 | Gate Automation North Yard | 390 | 8,512 | |
| 711 | BENSON WHSE LIGHTING | 390 | 1,231 | |
| 713 | CONCR & QUONSET HUTS | 390 | 18,880 | |
| 714 | CONCRETE VEH AREA | 390 | 7,687 | |
| 722 | S GATE & 5000 SECURI | 390 | 29,985 | |
| 712 | STORAGE YARD LITES | 390 | 8,620 | |
| 777 | QUONSET HUT BLDGS | 390 | 39,532 | |
| | | | 244,612 | |
| | Office Furniture, Equipment & Computers | | | |
| 776 | READER PRINTER | 391 | 38,461 | |
| 747 | CORP RECORDS ORGANIZ | 391 | 2,766 | |
| 775 | IS EMEREG BATTERY | 391 | 15,934 | |
| 743 | REORGANIZATION FURNI | 391 | 20,847 | |
| 744 | FURNITURE & EQUIP | 391 | 27,741 | |
| 1276 | Engraver Improvments | 391 | 8,066 | |
| 707 | OFF FURN & AQ | 391 | 291,916 | |
| 745 | BOARD ROOM REMODEL | 391 | 46,934 | |
| 1327 | Library Cntrl Files Additi | 391 | 19,082 | |
| 769 | OFFICE EQ | 391 | 62,674 | |
| 1095 | EPHRAIM PROJECT | 391 | 1,968,748 | |
| 718 | COPIERS | 391 | 3,284 | |
| 1449 | Mail Equipment 1999 | 391 | 8,166 | |
| 1447 | Audio & Visual Equipment 1 | 391 | 18,602 | |
| 1294 | OFFICE FURNITURE 1998 | 391 | 28,170 | |
| 1448 | Collater/Finisher 1999 | 391 | 45,250 | |
| 771 | BAR CODING SOFTWARE | 391 | 50,427 | |
| 723 | COPIERS | 391 | 4,136 | |
| 1452 | Video Editing System 1999 | 391 | 9,996 | |
| 733 | AS400 CONNECTIV SOFT | 391 | 6,285 | |
| 1450 | Platemaker 1999 | 391 | 6,950 | |
| 1588 | 2000 Furniture & Office Eq | 391 | 65,552 | |
| 719 | F3 FORM AUTOMATION | 391 | 25,000 | |

1.1060.100 Compl Constr General Plant

| | | | Totals | Transco Portion |
|---|---|---|---|---|
| 726 | EXERCISE EQ | 391 | 20,484 | |
| 709 | AUDIO VISUAL EQ | 391 | 10,128 | |
| 729 | CONF SPACE SAMPLE EQ | 391 | 4,916 | |
| 715 | OFFICE FURNITURE | 391 | 28,275 | |
| 728 | TABLE TOP FOLDER | 391 | 5,713 | |
| 727 | AS COPIERS | 391 | 9,138 | |
| 1605 | Apache Intranet Server | 391 | 21,933 | |
| 1499 | Furn & Equip Touchstone BI | 391 | 193,031 | |
| 710 | ROLM CBX SPARES | 391 | 5,896 | |
| 731 | COMPUTER UPGRADE | 391 | 350,632 | |
| 734 | PRINTING PRESS PURCH | 391 | 89,670 | |
| 735 | CHECK WRITING SYSTEM | 391 | 17,008 | |
| 732 | PWR GROUNDING & DATA | 391 | 57,897 | |
| 737 | SITE LICENSE CONVER | 391 | 4,524 | |
| 736 | SITE LICENSE CONVERS | 391 | 10,556 | |
| 730 | COPIERS | 391 | 10,134 | |
| 1451 | T-head 1999 | 391 | 8,144 | |
| 1110 | IBM INFO WIN 3476 DISPLAY | 391c | 1,997 | |
| 746 | BEN SSA TOKEN RING | 391c | 12,731 | |
| 741 | 1995 PC PURCHASE | 391c | 103,678 | |
| 740 | 1995 PC PURCHASE | 391c | 8,822 | |
| 717 | AS400 SYS BUYOUT | 391c | 67,725 | |
| 1117 | OFFICE FURNITURE 1996 | 391c | 29,295 | |
| 770 | SOFTWARE | 391c | 203,800 | |
| 1109 | IBM HIGH PERFORM TAPE SUBS | 391c | 62,949 | |
| 782 | AS LAN NETWORK | 391c | 24,313 | |
| 1105 | BACKBONE LAN SWITCHING-GRO | 391c | 13,068 | |
| 1116 | EMSS ELECT MKT SIMULATION | 391c | 53,774 | |
| 1128 | IBM/AS400 6607 DASD UPGRAD | 391c | 36,610 | |
| 716 | COMPUTORS & EQ | 391c | 93,056 | |
| 1138 | PERSONAL COMPUTER 97 BUDGE | 391c | 166,294 | |
| 742 | TOKEN RING (LAN) | 391c | 237,704 | |
| 795 | LOAD FLOW SOFTWARE | 391c | 34,111 | |
| 1277 | EDS Promod Accumen | 391c | 260,000 | |
| 1098 | UPGRADE NETWORK COMMUN INF | 391c | 44,873 | |
| 1099 | INTERNET SERVICES (ISP) | 391c | 33,610 | |
| 786 | PS5379 SOFTWARE | 391c | 13,996 | |
| 807 | BENSON EMS LAN | 391c | 11,572 | |
| 808 | IS COMPUTER BUDG 95 | 391c | 13,715 | |
| 1132 | PC CORPORATE | 391c | 144,432 | |
| 1115 | 1997 FURNITURE PURCHASE | 391c | 10,687 | |
| 798 | COMPUTORS | 391c | 93,628 | |
| 797 | DISC DRIVES | 391c | 277,942 | |
| 1129 | 97 NETWORK SERVICES SYS UP | 391c | 14,775 | |
| 1623 | Computer Sftwre Unicenter | 391c | 144,108 | |
| | | | 5,836,328 | |

1.1060.100 Compl Constr General Plant

| | | | Totals | Transco Portion |
|---|---|---|---|---|
| | Tools & Work Equipment | | | |
| 781 | BEN VEH WASH RACK | 394 | 17,103 | |
| 785 | FW VLV AIR WRENCH | 394 | 2,671 | |
| 783 | B CAN DEPRESSURIZER | 394 | 627 | |
| 790 | ROLL OFF WASTE CONTA | 394 | 5,346 | |
| 784 | DRUM CRUSHER | 394 | 16,745 | |
| 788 | APACHE CABLE MGMT SY | 394 | 108,099 | |
| 792 | HYDRAULIC TORQUE WRE | 394 | 24,075 | |
| 1155 | Freon Recovery Machine | 394 | 4,539 | |
| | | | 179,205 | 43,954 |
| | Laboratory Equipment | | | |
| 787 | NUCLEAR ALLOY TESTER | 395 | 56,343 | |
| 793 | TEST EQ | 395 | 489 | |
| 794 | TEST EQ | 395 | 1,405 | |
| 791 | ROTORPROBE TESTER | 395 | 14,458 | |
| 789 | TRNS LOAD FLOW ANALY | 395 | 13,283 | |
| 779 | TEST EQ | 395 | 4,653 | |
| 772 | DISPATCH RECORDER | 395 | 16,312 | |
| 1114 | MISC TEST EQUIPMENT | 395 | 47,990 | |
| 774 | TEST EQ BEN | 395 | 71,703 | |
| 778 | TEST EQ | 395 | 2,316 | |
| 773 | TEST EQ | 395 | 7,264 | |
| | | | 236,217 | 81,859 |
| | Communications Equipment | | | |
| 1340 | M/W Bicknell Telecom Upgrd | 397 | 12,375 | |
| 1348 | M/W Stewart Telecom Upgrad | 397 | 206 | |
| 1332 | M/W Benson Telecom Upgrade | 397 | 17,226 | |
| 1347 | M/W Tombstone Telecom Upgr | 397 | 206 | |
| 1349 | M/W Kartchner Telecom Upgr | 397 | 551 | |
| 1346 | M/W Morenci Telecom Upgrd | 397 | 14,497 | |
| 1299 | Microwave System Upgrade | 397 | 1,415,186 | |
| 1298 | EMS Unix Network Software | 397 | 13,230 | |
| 1334 | M/W Redtail Telecom Upgrd | 397 | 7,236 | |
| 1333 | M/W Texas Cnyn Telecom Upg | 397 | 24,450 | |
| 1120 | EPS NETWORK FIBER OPTIC EX | 397 | 2,564 | |
| 1344 | M/W Morenci PD Telecom Upg | 397 | 4,559 | |
| 1343 | M/W Pantano Telecom Upgrad | 397 | 16,067 | |
| 1342 | M/W Pistol Hill Telecom Up | 397 | 1,406 | |
| 1341 | M/W Vail Telecom Upgrade 0 | 397 | 51,667 | |
| 1339 | M/W Marana Telecom Upgrade | 397 | 237 | |
| 1336 | M/W Dos Condados Telcom Up | 397 | 17,108 | |
| 1338 | M/W Apache Telecom Upgrade | 397 | 8,865 | |
| 1337 | M/W Guthrie Peak Telcom Up | 397 | 10,846 | |
| 1335 | M/W Willcox Telecom Upgrd | 397 | 70 | |
| 1345 | M/W Greenlee Telecom Upgrd | 397 | 55,758 | |
| 800 | EMS & SOFTWARE | 397 | 6,835 | |

1.1060.100 Compl Constr General Plant

| | | | Totals | Transco Portion |
|---|---|---|---|---|
| 1350 | M/W Telecom Upgrade Spares | 397 | 20,706 | |
| 706 | EMS EQ GATEWAY | 397 | 278,399 | |
| 765 | GCEC REMOTE CONSOLE | 397 | 919 | |
| 799 | EMS & SOFTWARE | 397 | 6,968 | |
| 1097 | EMS REPLACEMENT | 397 | 5,722,992 | |
| 801 | PROCESS CONTROL | 397 | 2,764 | |
| 764 | TEC REMOTE CONSOLE | 397 | 3,875 | |
| 805 | MEC SPARE RTU | 397 | 6,258 | |
| 810 | EMS TEST EQ & TOOLS | 397 | 10,261 | |
| 768 | ANZA REMOTE CONSOLE | 397 | 2,353 | |
| 804 | AS PH LINE | 397 | 3,932 | |
| 806 | ANZA SPARE RTU | 397 | 4,487 | |
| 780 | COMMUNIC TEST EQ | 397 | 2,406 | |
| 766 | DEVC REMOTE CONSOLE | 397 | 4,542 | |
| 763 | SSVEC REMOTE CONSOLE | 397 | 3,287 | |
| 724 | EMS COMPUTORS | 397 | 8,535 | |
| 708 | SYS CONTROL CONSOLE | 397 | 233,791 | |
| 809 | EMS PC ACQUISITIONS | 397 | 8,095 | |
| 1108 | EPS SCADA DEVELOPMENT SYS | 397 | 31,208 | |
| 767 | MEC REMOTE CONSOLE | 397 | 5,129 | |
| 738 | BEN-APACHE RAID5 UPG | 397 | 9,647 | |
| 1106 | EPS PC REPLACEMENT | 397 | 23,393 | |
| 725 | NOVANET CONNECTIVITY | 397 | 4,030 | |
| 1107 | EMS PC NETWORK | 397 | 25,911 | |
| 739 | BEN-APACHE RAID5 UPG | 397 | 9,647 | |
| 802 | EMS TOOLS | 397 | 3,532 | |
| | | | 8,118,213 | 8,118,213 |
| | Total RUS 106 - General Plant | | 14,717,103 | 8,244,026 |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 114
TRANSCO
As of June 30, 2000



| Description | Item Number | Date Acquired | Orig/Book Value | Transco Ownership | RUS | CNTY | TAX DIST |
|---|---|---|---|---|---|---|---|
| Aquisition Adj. | 1 | 02/20/61 | 17,651 | 4,413 | 114 | 2 | 2600 |
| Plnt-Elec Acquist Adj | | | 17,651 | 4,413 | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 301
TRANSCO
As of June 30, 2000



| Description | Item Number | Date Acquired | Orig/Book Value | Transco Ownership | RUS | CNTY | TAX DIST |
|---|---|---|---|---|---|---|---|
| ORGANIZATION | 2 | 02/20/61 | 6,059 | 1,515 | 301 | 2 | 2600 |
| Total Plnt-Organization | | | 6,059 | 1,515 | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 302
TRANSCO
As of June 30, 2000



| Description | Item Number | Date Acquired | Orig/Book Value | Transco Ownership | RUS | CNTY | TAX DIST |
|---|---|---|---|---|---|---|---|
| FRANCHISE | 3 | 02/20/61 | 993 | 248 | 302 | 2 | 2600 |
| Total Franchise & Consent | | | 993 | 248 | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 303
TRANSCO
As of June 30, 2000



| Description | Item Number | Date Acquired | Orig/Book Value | RUS | CNTY | TAX DIST |
|---|---|---|---|---|---|---|
| SPIRIT MTN BLDG DOE | 5 | 12/31/91 | 26,071 | 303 | 0 | 0 |
| ORACLE SUB (SCIP) | 50 | 10/31/90 | 941,686 | 303 | 11 | 200 |
| DSM JT5416 | 4 | 12/31/93 | 216,810 | 303 | 2 | 980 |
| DAVIS DAM DOE INTANG | 49 | 08/31/84 | 969,428 | 303 | 8 | 1579 |
| Plnt-Intangible Plnt | | | 2,153,995 | | | |

**Arizona Electric Power Coop**
Non Generation Assets - RUS 105
TRANSCO
As of June 30, 2000



| Description | Item # | Date Acquired | Orig. Book Value | RUS | FCN | County | TAX DIST |
|---|---|---|---|---|---|---|---|
| LAND ORO VALLEY | 1502 | 12/31/99 | 177,476 | 105 | TRN | 10 | 1011 |
| LAND ORO VALLEY | 1503 | 12/31/99 | 199,738 | 105 | TRN | 10 | 1011 |
| Total Plnt-Elec Hld for Future Use | | | 377,214 | | | | |

**Arizona Electric Power Cooperative, Inc.**
Cap Proj/Budget Purpose REA 107
To Date Expenditures by Project
As of June 30, 2000



| Description | Current Month | Year To Date | Inception To Date |
|---|---|---|---|
| Budget Purpose 2 Capital - Transmission | | | |
| 912973 EMS REPLACEMENT | 0 | (150,000) | 0 |
| 952359 M/W TOWER SAFETY CLIMBERS | 0 | 0 | 17,320 |
| 5000025010 WSCC & IPP Network Gateway | 68 | 405 | 13,400 |
| 5000029010 Microwave Sys Upgrade | (15,115) | (83,627) | (96,261) |
| 5000032010 Sahuarita Substation | 18,087 | 1,939 | (38,454) |
| 5000032011 SAHUARITA TAP, PANT/BICK 230KV | 368 | 7,718 | 68,600 |
| 5000037010 Topock Substation | (451) | (14,603) | 2,034 |
| 5000202010 Thornydale Substation | 14,229 | 545,316 | 591,988 |
| 5000204010 Greenlee Station Battery Repla | 1,828 | 1,977 | 7,722 |
| 5000205010 Morenci-AEPCO Sta Battry Repla | 1,791 | 7,133 | 7,658 |
| 5000209010 Greenlee Tertiary Tap | 0 | 0 | 387 |
| 5000250010 MARANA SUBSTATION UPGRADE | 761,976 | 1,099,461 | 1,102,685 |
| 5000267012 Repl Str 105 Vail/Bick 99 Trns | 0 | (63,291) | 0 |
| 5000267013 Repl Str 113 Vail/Bick 99 Trns | 60 | 354 | 11,709 |
| 5000267014 Repl Str#112 Vail/Bick 99 Trns | 263 | 2,080 | 51,549 |
| 5000268010 Repl Str 278 loc 209 2000 Tran | 68 | 7,313 | 13,401 |
| 5000303010 Reroute Grnlee/Grnlee 345KV Ln | 79,574 | 287,131 | 328,232 |
| 5000320010 Under Freq Load Shed WSCC | (1,204) | 848 | 29,321 |
| 5000322010 Install Str 17a 3pts/Avra Vall | 0 | (7,885) | 0 |
| 5000343010 Three Pts Capacitor Replacemnt | 1,698 | 88,851 | 88,851 |
| 5000344010 Bicknell Capacitor Replacemnt | 270 | 540 | 540 |
| 5000345010 Riviera Capacitor Replacemnt | 0 | 45 | 45 |
| 5000361010 Apache-Butterfield Str #2 | 0 | 2,979 | 2,979 |
| Total Budget Purpose 2 Capital - Transmission | 863,513 | 1,734,682 | 2,203,705 |

**Arizona Electric Power Cooperative, Inc.**
Cap Proj/Budget Purpose REA 107
To Date Expenditures by Project
As of June 30, 2000



| Description | Current Month | Year To Date | Inception To Date |
|---|---|---|---|
| Budget Purpose 3 Capital - Generation | | | |
| 923001 ASH DISPOSAL FACILITY | 0 | (716,997) | 699 |
| 963477 Deep Well #9 Replacement | 0 | (18) | 0 |
| 5000003011 ST2A Mill Liner Replacement | 0 | 343 | 343 |
| 5000003013 ST3B Mill Liner Replacement | 28,350 | 18,000 | 30,192 |
| 5000003014 ST3C Mill Liner Replacement | 28,400 | (39,207) | 30,207 |
| 5000004010 ST2 Clng Twr Drift Eliminator | 210,033 | 216,452 | 216,452 |
| 5000015010 Coal Handling Control Upgrade | 482 | 2,376 | 67,792 |
| 5000016010 Control Equip Room Fire Supr. | 0 | 0 | 1,625 |
| 5000018011 St2 Split Limestone | 0 | (57,860) | (3,210) |
| 5000018012 St3 Split Limestone | (51,844) | (43,602) | 0 |
| 5000018013 ST2 Modulating Bypass Damper | 0 | 129 | 25,378 |
| 5000018014 ST3 Modulating Bypass Damper | 0 | 4,365 | 36,424 |
| 5000018015 ST2 Scrubber Tower Trays | 0 | 0 | 18,993 |
| 5000018016 ST3 Scrubber Tower Trays | 0 | 0 | 19,101 |
| 5000018019 ST2&3 Inhibited Oxidation | 0 | 0 | 7,256 |
| 5000021010 ST2 Ash Handl'g Contrls Upgrad | 1,904 | 2,901 | 28,706 |
| 5000021011 ST3 Ash Handl'g Contrls Upgrad | 1,603 | 3,128 | 24,685 |
| 5000087010 ST2 CONDENSATE PUMP CAPACITY | 351 | 851 | 966 |
| 5000087011 ST3 CONDENSATE PUMP CAPACITY | 201 | 350 | 374 |
| 5000101011 ST3 POWER SYS STABILIZERS | 0 | 0 | 41,074 |
| 5000106010 ST2 CO Monitor | 40 | 237 | 7,850 |
| 5000114010 4A & 4B Belt Fire Protect Upgr | 0 | 0 | 1,675 |
| 5000213010 REAL TIME GAS METERING | 574 | 14,165 | 40,214 |
| 5000214010 POTABLE WATER SYSTEM | 201 | (247,207) | 4,281 |
| 5000259010 ST2 Gen. Protect Relay Upgd | 104 | 20,396 | 20,396 |
| 5000259011 ST3 Gen. Protect Relay Upgd | 260 | 50,829 | 50,829 |
| 5000284010 ST2 High Energy Pipe Sys Upgra | 0 | (279) | 0 |
| 5000284011 ST3 High Energy Pipe Sys Upgra | 443,638 | 363,111 | 449,917 |
| 5000287010 ST2 5kv Cable Tray Install | 9,877 | 99,380 | 140,391 |
| 5000287011 ST3 5kv Cable Tray Install | 13,082 | 63,575 | 148,731 |
| 5000288010 Clg Twr BD Discharge Ditch | 0 | (565) | 0 |

**Arizona Electric Power Cooperative, Inc.**
Cap Proj/Budget Purpose REA 107
To Date Expenditures by Project
As of June 30, 2000



| Description | Current Month | Year To Date | Inception To Date |
|---|---|---|---|
| Budget Purpose 3 Capital - Generation (continued) | | | |
| 5000314010 Thermal Camera | 0 | 60,819 | 60,819 |
| 5000365010 OSS Labor Facility Building | 11,458 | 11,458 | 11,458 |
| Total Budget Purpose 3 Capital - Generation | 698,712 | (172,869) | 1,483,617 |
| Budget Purpose 6 Capital - All Other | | | |
| 5000216010 APACHE INTRANET SERVER | 0 | (21,949) | (350) |
| 5000224010 NETWORK ROUTERS SYS OPS NW | 164 | 967 | 32,025 |
| 5000225010 RTU TEST SETS | 43 | 253 | 8,379 |
| 5000227010 OFFICE FURNITURE 1998 | 0 | 5,300 | 0 |
| 5000228010 SF 6 GAS ANALYZER | 28 | 168 | 5,554 |
| 5000289011 99 Vehicle Repl - TRANSCO | 0 | (518) | 0 |
| 5000290010 1999 Furn & Office Equip | 0 | (65,552) | 0 |
| 5000294010 1999 Reroofing Building | 0 | 0 | 17,703 |
| 5000332010 Direct Access System Implement | 89,371 | 348,376 | 348,376 |
| 5000336010 Upgrade Engraving System | 25,017 | 25,017 | 25,017 |
| 5000337010 Cutter for collator | 0 | 15,727 | 15,727 |
| 5000350010 GENCO Veh Replmnt/Acquis 2000 | (58,932) | 4,905 | 4,905 |
| 5000351010 TRANSCO Veh Rplmnt/Acquis 2000 | (59,138) | 0 | 0 |
| 5000358010 Copier Machine Graphics | 0 | 30,025 | 30,025 |
| Total Budget Purpose 6 Capital - All Other | (3,448) | 342,719 | 487,362 |
| Total Construction Work in Progress | 1,558,777 | 1,904,532 | 4,174,684 |

## SECTION H

## DEEDED LAND, LEASES AND RIGHT OF WAYS

## COCHISE COUNTY

**LEASES:**

ARIZONA STATE LAND DEPARTMENT

1. Dos Cabezas Communication site lease with Arizona State Land Department #03-34107, dated 11-1-95, recorded in docket # 960100656.

2. Texas Canyon Communication site lease with Arizona State Land Department #03-72450, dated 3-7-1994 and recorded in docket #940616215.

**R/W EASEMENTS:**

ARIZONA STATE LAND DEPARTMENT

1. R/W #14-3254 for the Apache to Redtail transmission line, dated 3-1-93 and recorded in docket # 970306358 and any subsequent amendments.

2. R/W #14-5279 for the Apache to Pantano transmission line, dated 2-27-1975 and recorded in docket #860101908 and an amendment dated 7-15-1992 and any subsequent amendments.

3. R/W #18-72418 for the Texas Canyon communication site access road, dated 1-12-99 and recorded in docket # 990308358.

4. R/W #14-3311 for the Apache to Hayden transmission line, dated 5-17-1993 and recorded in docket #940411018 and any subsequent amendments.

5. R/W #14-94618 for the Butterfield to San Rafael transmission line, dated 6-22-1988 and recorded in docket # 890100417 and an amendment dated 2-2-1993 and recorded in docket # 931235188 and any subsequent amendments.

6. R/W #18-102661 for the Dos Cabezas communication site access road, dated 11-1-95 and recorded in docket # 970410690.

BUREAU OF LAND MANAGEMENT

1. R/W Grant #A-032556 for the Apache to Hayden transmission line, dated 7-30-1963 and recorded in Docket #86101916 (also covers Pima, Pinal and Gila Counties) and an amendment dated 10-5-1977 and recorded in Docket #86001913 and any subsequent amendments.

2. R/W Grant #A-032324 for the Apache to Redtail to Dos Condado transmission line, dated 7-23-1963 and recorded in Docket #86001914 (also covers Graham County).

3. R/W Grant #A-22638 for the Butterfield to San Rafael transmission line, dated 2-10-1988 and recorded in Docket #880304524.

PRESCRIPTIVE RIGHT EASEMENTS: Three total, identified by section and county.

1. No document for a portion of land crossed by the Apache to Butterfield 230kv line in section 10, Township 16 South, Range 24 East.
2. No document for a portion of land crossed by the Apache to Butterfield 230kv line in section 15, Township 16 South, Range 24 East.
3. No document for a portion of land crossed by the Butterfield to Pantano 230kv line in section 6, Township 17 South, Range 19 East.

PRIVATE:

All other easements and leases, licenses, permits etc. recorded or not of record granted to Arizona Electric Power Cooperative, Inc.

UNITED STATES FOREST SERVICE:

1. Permit #4041 for an easement for the Apache to Bicknell transmission line dated 11-2-1972 and unrecorded.

## GILA COUNTY

**LEASES:**

UNITED STATES FOREST SERVICE:

1. Permit #4268-01 for a special use permit for the Pinal Peak Communications Site dated 5-26-1992 and unrecorded.

**EASEMENTS:**

PRESCRIPTIVE RIGHT EASEMENTS: One total, identified by section and county.

1. No document for a portion of land crossed by the Apache to Hayden 115kv line in section 13, Township 5 South, Range 15 East.

PRIVATE:

All other easements and leases, licenses, permits etc. recorded or not of record granted to Arizona Electric Power Cooperative, Inc.

## GRAHAM COUNTY

**R/W EASEMENTS:**

ARIZONA STATE LAND DEPARTMENT

1. R/W #14-3254 for the Apache to Redtail transmission line, dated 3-1-93 and with the original recorded in Cochise County and any subsequent amendments.

2. R/W #38979 for the Doc Condado to Greenlee transmission line, dated 10-20-1987 and originally recorded in Greenlee County and any subsequent amendments.

3. R/W #14-760 for the Dos Condado to Romney transmission line, dated 5-28-1989 and originally recorded in Greenlee County and any subsequent amendments.

BUREAU OF LAND MANAGEMENT

1. R/W Grant #A-9015 for the Dos Condado to Morenci to Greenlee transmission line, dated 4-29-1977 and recorded in Book 386, pages 357-363 (also covers Greenlee County).

PRESCRIPTIVE RIGHT EASEMENTS: One total, identified by section and county.

1. No document for a portion of land crossed by the Dos Condado to Romney 69kv line in section 24, Township 8 South, Range 30 East.

PRIVATE:

All other easements and leases, licenses, permits etc. recorded or not of record granted to Arizona Electric Power Cooperative, Inc.

## GREENLEE COUNTY

**DEEDS:**

1. Duncan Substation: A parcel of land in Lot 2 of Section 30, Township 8 South, Range 32

East, together with all improvements thereon, described in certain deed dated July 18, 1978 and recorded in Book 97, page 525.

**R/W EASEMENTS:**

ARIZONA STATE LAND DEPARTMENT

1. R/W #14-38979 for the Dos Condado to Greenlee transmission line, dated 10-20-1987 and recorded in Book 165, pages 60-61 and two amendments, one dated 10-20-1992 and the other dated 12-8-1998 along with any other subsequent amendments.

2. R/W #14-760 for the Dos Condado to Romney transmission line, dated 5-28-1989 and recorded in Book 174, pages 646-653 and any subsequent amendments.

BUREAU OF LAND MANAGEMENT

1. R/W Grant #PHXO-085856 for the Dos Condado to Romney transmission line from BLM dated 2-14-1950 and unrecorded and an assignment to AEPCO dated 12-16-1986 recorded in Book 169 page 238.

2. R/W Grant #AZA-9331 for the Guthrie Peak Communication Site, dated 2-26-1976 and recorded in Book 164 pages 576-578.

3. R/W Grant #A-25181 for the Guthrie Peak Access Road, dated 4-8-1992 and recorded in Book 187 pages 503-508.

PRIVATE:

All other easements and leases, licenses, permits etc. recorded or not of record granted to Arizona Electric Power Cooperative, Inc.

## MOHAVE COUNTY

**LEASES:**

ARIZONA STATE LAND DEPARTMENT

1. Round Valley communication site, special land use permit with Arizona State Land Department #23-99629, dated 5-8-1996, recorded in Book 2977, pages 541-549.

**R/W EASEMENTS:**

ARIZONA STATE LAND DEPARTMENT

1. R/W #72-14908 for the Davis Dam to Riviera transmission line, dated 12-17-1993 and recorded in Book 2345, pages 723-724 and any subsequent amendments.

2. R/W #18-103768 for the Topock Substation access road, dated 6-18-1998 and recorded in Book 3179, pages 430-443 and any subsequent amendments.

BUREAU OF LAND MANAGEMENT

1. R/W Grant #A-14908 for the Davis Dam to Riviera transmission line, dated 5-14-1981 and recorded in Book 967 pages 360-367.

2. R/W Grant #AZA-30307 for the Topock substation and access road, dated 1-28-1998 and recorded in Book 3179 pages 422-429.

3. R/W Grant #AZA-26177 for the Kingman Tap Communication Site, dated 12-16-1991 and recorded in Book 1989 pages 526-531.

4. R/W Grant #A-16574 for the Planet Tap to Bagdad transmission line, dated 3-19-1981 and recorded in Book 1224 pages 265-269 and an amendment dated 5-17-1983 and recorded in Yavapai County in Book 1559, pages 633-640.

5. R/W Grant #AZA-30623 for the Hayden Peak Communication Site, dated 9-25-1998 and recorded in Book 3179 pages 410-421.

6. R/W Grant #AR-018713-A for the Smith Peak Communication Site, dated 8-21-1982 and recorded in Book 1224 pages 270-273.

PRIVATE:

All other easements and leases, licenses, permits etc. recorded or not of record granted to Arizona Electric Power Cooperative, Inc.

## PIMA COUNTY

**DEEDS:**

1. Marana Substation: A parcel of land in the southwest 1/4 of the southwest 1/4 of the northwest 1/4 of Section 26, Township 11 South, Range 10 East, together with all improvements thereon, described in a certain deed dated May 25, 1964 and recorded in book 2269, pages 108-112, excluding approximately 6.85 acres sold to Avra Valley Fire District in 1983. Also, a parcel of land described in a certain deed, dated April 4, 1989 and recorded in Book 8522, pages 1577-1579.

2. Moore Road Tap: A vacant parcel of land in the southeast 1/4 of Section 25, Township 11 South, Range 13, East, described in certain deed, dated January 19, 1989, and recorded in Book 08465, pages 1974-1975.

3. Avra Valley Substation: A parcel of land in the West half of Section 11, Township 13 South, range 10 East, together with all improvements thereon, described in certain deed dated November 21, 1996 and recorded in Book 10433, pages 837-839.

4. Sahuarita Substation: A parcel of land in the Northeast 1/4 of Section 8, Township 17 South, range 14 East, together with all improvements thereon, described in certain deed dated March 22, 1999 and recorded in Book 11015, pages 1783-1785.

**LEASES:**

ARIZONA STATE LAND DEPARTMENT

1. Pistol Hill Communication site lease with Arizona State Land Department #03-34108, dated 11-1-95, recorded in Book 10208, pages 1822-1840.

2. Thornydale Project right of entry with Arizona State Land Department #29-104563.

3. Thornydale Substation site lease with Arizona State Land Department #03-105213 not yet finalized.

**R/W EASEMENTS:**

ARIZONA STATE LAND DEPARTMENT

1. R/W #14-5280 for the Pantano to Kartchner transmission line, dated 2-26-1975 and recorded in Book 7701, pages 1148-1148A and 1149-1149A and an amendment dated 2-5-1993 and recorded in Book 9489, pages 675-680 along with any other subsequent amendments.

2. R/W #14-24966 for the Apache to Pantano transmission line, dated 7-25-1984 and recorded in Book 7710, pages 717-722 and an amendment dated 10-5-1993 recorded in Book 9644, pages 423-427.

3. R/W #14-3311 for the Apache to Hayden transmission line, dated 5-17-1993 and originally recorded in Cochise County and any subsequent amendments.

4. R/W #71-4660 for the Bicknell to Three Points transmission line, dated 10-14-1969 and recorded in Book 4656, pages 143-146 and an amendment dated 3-3-1993 and recorded in Book 9525 pages 1096-1098.

5. R/W #72-4410 for the Three Points to Marana transmission line, dated 2-19-1993 and recorded in Book 9486, pages 1153-1154 and any subsequent amendments.

6. R/W #14-52251 for the Bicknell to Three Points transmission line, dated 10-3-1991 and recorded in Book 9461, pages 661-670 and an amendment dated 5-19-1997 not recorded.

7. R/W #14-52300 for the Three Points to Valencia transmission line, dated 5-28-1993 and recorded in Book 9635, pages 403-412 and an amendment dated 8-3-1994 not recorded.

8. R/W #14-93703 for the Moore Tap to Thornydale transmission line, dated 12-17-1987 and recorded in Book 8251, pages 1403-1406 and any subsequent amendments.

9. R/W #14-101676 for the Vail to Bicknell transmission line, dated 2-10-1996 and recorded in Book 10644, pages 1742-1751 and any subsequent amendments.

10. R/W #18-104626 for the Sahuarita Substation access road, dated 5-6-1999 and recorded in Book 11092, pages 1220-1230 and any subsequent amendments.

11. R/W #18-105207 for the Thornydale transmission line, dated 7-6-2000 and recorded in Book 11375, pages 339-349 and any subsequent amendments.

BUREAU OF LAND MANAGEMENT

1. R/W Grant #A-4410 for the Bicknell to Three Points transmission line, dated 1-29-1971 and recorded in Book 7701 pages 1153-1156.

2. R/W Grant #A-7428/7621 for the Apache to Bicknell transmission line, dated 5-21-1974 and recorded in Book 7701 pages 1150-1152.

3. R/W Grant #AZ-031023 for the Three Points to Marana transmission line, dated 10-5-1961 and recorded in Book 9486 page 1152.

4. R/W Grant #AZA-27284 for the Three Points to Valencia transmission line, dated 12-15-1993 and recorded in Book 9689, pages 930-932.

PRESCRIPTIVE RIGHT EASEMENTS: Eight total, identified by section and county.

1. No document for a portion of land crossed by the Pantano to Bicknell 230kv line in section 34, Township 17 South, Range 17 East.
2. No document for a portion of land crossed by the Pantano to Bicknell 230kv line in section 34, Township 17 South, Range 13 East.
3. No document for a portion of land crossed by the Pantano to Bicknell 230kv line in section 33, Township 17 South, Range 13 East.

4. No document for a portion of land (20' strip adjacent to an existing easement) crossed by the Bicknell to Three Points 115kv line in sections 16, 21, 25, 26 and 27, Township 17 South, Range 12 East.
5. No document for a portion of land crossed by the Three Points to Marana 115kv line in section 34, Township 11 South, Range 10 East.
6. No document for a portion of land crossed by the Three Points to Marana 115kv line in section 35, Township 11 South, Range 10 East.
7. No document for a portion of land crossed by the Three Points to Marana 115kv line in section 26, Township 12 South, Range 10 East.
8. No document for a portion of land crossed by the Three Points to Marana 115kv line on the Tohono O'Odham Reservation in sections 14, 23, 26, Township 14 South, Range 10 East.

PRIVATE:

All other easements and leases, permits etc. recorded or not of record granted to Arizona Electric Power Cooperative, Inc.

## PINAL COUNTY

**R/W EASEMENTS:**

ARIZONA STATE LAND DEPARTMENT

1. R/W #14-3311 for the Apache to Hayden transmission line, dated 5-17-1993 and recorded in docket #2010833-848 and any subsequent amendments.

PRIVATE:

All other easements and leases, permits etc. recorded or not of record granted to Arizona Electric Power Cooperative, Inc.

## SANTA CRUZ

**R/W EASEMENTS:**

ARIZONA STATE LAND DEPARTMENT

1. R/W #14-5281 for the Pantano to Kartchner transmission line, dated 2-26-1975 and recorded in Book 452, pages 482-484 and any subsequent amendments.

PRIVATE:

All other easements and leases, permits etc. recorded or not of record granted to Arizona Electric

Power Cooperative, Inc.

## YAVAPAI COUNTY

**R/W EASEMENTS:**

ARIZONA STATE LAND DEPARTMENT

1. R/W #18-85987 for the Planet Tap to Bagdad transmission line, dated 5-12-1993 and recorded in Yavapai County and any subsequent amendments.

2. R/W #72-16574 for the Planet Tap to Bagdad transmission line, originally granted to the Bureau of Reclamation and not recorded.

BUREAU OF LAND MANAGEMENT

1. R/W Grant #A-16574 for the Planet Tap to Bagdad transmission line, an amendment dated 5-17-1983 and recorded in Yavapai County in Book 1559, pages 633-640.

PRIVATE:

All other easements and leases, permits etc. recorded or not of record granted to Arizona Electric Power Cooperative, Inc.

# Schedule 1 to the Restructuring Agreement

Financial & Other Assets
as of 6/30/2000

| | | |
|---|---|---|
| **Other Property & Investments:** | | |
| RUS Account 123 - Investments in Associated Companies - Patronage Capital | | 83,168 |
| RUS Account 123 - Investments in Associated Companies - CFC Capital Term Certificates | | 1,027,239 |
| RUS Account 123 - Investment in CSP | | 1,000,000 |
| RUS Account 128 - Special Funds | | |
| a). Reid & Priest Restructuring | | 92,602 |
| Total Other Property & Investments | | 2,203,009 |
| **Current & Accrued Assets:** | | |
| RUS Account 131 - General Funds | | 78,495 |
| RUS Account 134 - Special Transmission Spool Deposit | | 14,559 |
| RUS Account 136 - Temporary Investments | | 2,783,547 |
| RUS Account 142 - Accounts Receivable - Transmission Sales | | 3,537,592 |
| RUS Account 141 - Notes Receivable - AIS | | 25,424 |
| RUS Account 143 - Accounts Receivable - Other | | 101,245 |
| RUS Account 154 - Materials & Supplies | | 792,797 |
| RUS Account 165 - Prepayments | | |
| a). Rights of Way | 877,638 | |
| b). Insurance | 7,824 | |
| c). Other | 23,417 | 908,879 |
| Total Current & Accrued Assets | | 8,242,538 |
| **Deferred Debits:** | | |
| RUS Account 181 - Unamortized Debt Discount | | 2,890,382 |
| RUS Accounts 183-186 - Other Deferred Debits | | |
| a). Unamortized Loss on Reaquired Debt | 463,023 | |
| b). Preliminary Surveys & Job Tickets | 252,497 | 715,520 |
| Total Deferred Debits | | 3,605,902 |
| Grand Total Transmission Related Financial & Other Assets | | 14,051,449 |

## Schedule 1 to the Restructuring Agreement:

Regulatory Assets Assigned to Southwest Transmission
as of 6/30/2000

**Regulatory Assets:**

| | | |
|---|---|---|
| 1. Carbon Coal Investment | | $11,747,880 |
| 2. Unamortized Debt Discount | | |
| a). 1993 FFB Repricing | 3,935,175 | |
| b). 1994 FFB Repricing | 4,624,441 | |
| c). 1995 FFB Repricing | 1,271,165 | |
| d). Cooperative Utilities Trust Certificate | 1,888,840 | |
| | 11,719,621 | |
| Less: Southwest Transmission Portion (24.66%) | (2,890,382) | 8,829,239 |
| Total Regulatory Assets Assigned to Southwest Transmission | | $20,577,119 |

## Schedule 1 to the Restructuring Agreement:

Non-Generating Liabilities
as of 6/30/2000

## Non-Generating Liabilities:

| | |
|---|---|
| RUS Account 228 - Accumulated Operating Provision (SFAS 106) | $ 113,322 |
| RUS Account 232 – Accounts Payable | 629,615 |
| RUS Account 236 – Accrued Taxes (property, employee, sales) | 874,229 |
| RUS Account 242 – Other Accrued Liabilities (restructuring, payroll & vacation) | 158,635 |
| RUS Accounts 253 – Deferred Credits (prepaid power-transm.) | 749,608 |
| Total Non-Generating Liabilities | $2,525,509 |

## Schedule 2 to the Restructuring Agreement:

CSP Assets & Liabilities
as of 6/30/2000

**Assets:**

| | | |
|---|---|---|
| RUS Account 123 - Investment in Subsidiary Company (TSE Promotional Products Inc.) | | $ 55,000 |
| RUS Account 128 - Special Funds | | 85,833 |
| RUS Account 134 - Special Deposits (Tucson office) | | 14,883 |
| RUS Account 136 - Net Temporary Investments (to cover SFAS 106, accrued payroll & vacation) | | 2,484,503 |
| RUS Account 143 - Accounts Receivable - Other | | 172,368 |
| RUS Accounts 183-186 - Other Deferred Debits | | |
| 1. Deferred Revenue | (51,966) | |
| 2. Other Deferred Costs | 2,716 | (49,250) |
| Total Assets | | $2,763,337 |

**Liabilities:**

| | |
|---|---|
| RUS Account 228 - Accumulated Operating Provision (SFAS 106) | 953,924 |
| RUS Accounts 236, 242 - Other Current & Accrued Liabilities (accrued lease deposit, payroll & vacation) | 1,542,822 |
| RUS Account 253 - Deferred Credits | 85,833 |
| Total Liabilities | $2,582,579 |
| Total Assets less Liabilities | $ 180,758 |

# Schedule 3 to the Restructuring Agreement

Basis for the Allocation of Debt & Equity
as of 6/30/2000

The debt aquired by TRANSCO is:

| | | |
|---|---|---|
| 1. | Aquisition of fixed assets at Fair Market Value | $66,857,784 |
| 2. | Aquisition of other assets with debt | |
| | a. Financial assets, cash, investments, (incl. a portion of AEPCO's earlier investment in CSP) | $2,579,524 |
| | b. Accounts receivable | $3,638,837 |
| | c. Material inventories | $792,797 |
| | d. Prepayments and other accrued assets | $908,879 |
| | e. Unamortized debt discount + other deferred debits (incl. unamort. loss on reaquired debt + preliminary surveys, & job tickets) | $3,605,902 |
| 3. | Assignment of AEPCO's Regulatory Assets | $20,577,119 |
| 4. | Debt associated with CSP allocation of cash** | $44,580 |
| 5. | Assignment of Positive equity *** | ($1,087,944) |
| | Total Transco Long Term Debt * | $97,917,478 |

*: The FFB Debt % Ratio is 68.55041% - GENCO, 31.44959% - TRANSCO

**: CSP acquires the following assets without an offsetting liability from AEPCO. Since CSP must pay for these assets with cash, the cash is subsequently allocated (like the other assets) from AEPCO to TRANSCO. TRANSCO aquires it's share of the $180,758 with debt.

| | |
|---|---|
| Invest. in assoc. - TSE Promo. | $55,000 |
| Tucson Office deposit | $14,883 |
| Employee receivables | $84,540 |
| Other rec., deferred debits (JT | $26,335 |
| | $180,758 |

& $180,758 X .2466276 (TRANSCO share on basis of Total Utility Plant) = $44,580

***: The equity accounts are split on the basis of utility plant therefore, AEPCO keeps 75.337% and TransCo acquires 24.663%. There are two things to note about the split of equity. The first is that the equity AEPCO ended 6/30/00 with is split only between AEPCO and TRANSCO, not CSP. CSP gets it's equity from the $4 million it is capitalized with. The second thing to note is that there are two "pieces" of equity The first is the patronage capital that AEPCO allocated among it's members in 1974 amounting to $1,843,609. That amount is split first between AEPCO and TRANSCO and then again among the original patrons such that the sum of the patronage capital in AEPCO plus the sum of the patronage capital in TRANSCO totals to the same amount as the original patronage allocated in 1974.

first,

| | AEPCO | TRANSCO | Total |
|---|---|---|---|
| Duncan | $40,010 | $13,098 | $53,108 |
| Graham | $115,296 | $37,744 | $153,040 |
| Mohave | $26,157 | $8,563 | $34,720 |
| Sulphur | $479,911 | $157,106 | $637,017 |
| Trico | $727,550 | $238,174 | $965,724 |
| a. | $1,388,924 | $454,685 | $1,843,609 |

then, split the remaining positive equity, but only between AEPCO & TRANSCO, and no further (ie: at the member level).....

| | AEPCO | TransCo | Total |
|---|---|---|---|
| b. | $1,934,417 | $633,259 | $2,567,676 |
| (a) + (b) = | $3,323,341 | $1,087,944 | $4,411,285 |

Proof: if one adds the two together, $1,843,609 + $2,567,676, the result of $4,411,285 equals the total equity on the 6/30/00 AEPCO balance sheet.

B

# PARTIAL REQUIREMENTS

# CAPACITY AND ENERGY AGREEMENT

**BETWEEN**

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.**

**AND**

**MOHAVE ELECTRIC COOPERATIVE, INC.**

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# PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

## PARTIES

The Parties to this PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT (Agreement) are Mohave Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized under the laws of the State of Arizona (Member), and Arizona Electric Power Cooperative, Inc. (AEPCO), a non-profit corporation as defined and organized under the generation and transmission electric cooperative laws of the State of Arizona. Member and AEPCO are referred to in this Agreement individually as"Party" and collectively as "Parties."

## RECITALS

A. AEPCO and the Member are parties to that certain Wholesale Power Contract, dated as of_____, as amended on_____ (Existing Wholesale Power Contract).

B. AEPCO's membership consists of Class A Members, Class B Members and Class C Members. AEPCO's Class A Members, as of the Effective Date, consist of Anza Electric Cooperative, Inc.; Duncan Valley Electric Cooperative, Inc.; Graham County Electric Cooperative, Inc.; Mohave Electric Cooperative, Inc.; Sulphur Springs Valley Electric Cooperative, Inc.; and Trico Electric Cooperative, Inc., which members are referred to individually and collectively in this Agreement as "Class A Member(s)". The Class B Members of AEPCO, as of the Effective Date, are the City of Mesa and Morenci Water & Electric Company. The sole Class C Member of AEPCO, as of the Effective Date, is the Salt River Project Agricultural Improvement and Power District. The Class A, B and C Members are referred to in this Agreement collectively as "Members". The Class A Members, except Member, are referred to in this Agreement collectively as "All Requirements Members," and individually as an "All Requirements Member."

C. AEPCO's Class A Members, including the Member, are electric cooperative non-profit membership corporations or non-profit corporations conducting business in the States of Arizona, New Mexico and California. Each Class A Member originally joined with the other Class A Members, either to form AEPCO, or to join in AEPCO's operations pursuant to an all-requirements agreement with AEPCO similar to the Existing Wholesale Power Contract. The Parties are executing this Agreement contemporaneously with the execution of a transmission agreement between Southwest Transmission Electric Power Cooperative, Inc., a non-profit corporation organized under the electric power generation and transmission cooperative corporation laws of the State of Arizona (TRANSCO) and Member; and of a Resource integration agreement concerning the pooling and operation of certain Resources.

D. As part of the overall restructuring of its system, AEPCO will transfer its Transmission Business substantially as an entirety to TRANSCO. On or before the Closing Date, AEPCO will transfer its CSP Business substantially as an entirety to Sierra Southwest Electric Power Cooperative Services, Inc. (CSP), a non-profit corporation organized under the electric power generation and transmission cooperative corporation laws of the State of Arizona. Such restructuring of AEPCO will be accomplished pursuant to the provisions of the Restructuring Agreement, dated _____, _____, entered into contemporaneously herewith by and among AEPCO, TRANSCO and CSP (Restructuring Agreement), and the Member Agreement, dated _____, _____, entered into contemporaneously herewith by and among AEPCO, TRANSCO, CSP and the Class A Members (Member Agreement). A copy of the Member Agreement is attached hereto without schedules or exhibits as Attachment A solely for informational purposes and the convenience of the Parties.

E. AEPCO, as of the Closing Date, owns and operates electric generation facilities and assets and rights to electric energy and capacity under various purchase agreements (collectively, the "Existing Resources").

F. AEPCO has obligations for loans which, in whole or in part, financed the construction of generation and transmission facilities, all of which are evidenced by mortgage notes (collectively, the "AEPCO Notes") payable to or guaranteed by the United States of America (Government), acting through the Rural Utilities Service (RUS), as successor to the Rural Electrification Administration, and the National Rural Utilities Cooperative Finance Corporation (CFC), and loans made by, or securities issued to, or obligations undertaken to others, including the trustees and bond holders of the Pollution Control Revenue Refunding Bonds (Pooled Series 1997C ), the Solid Waste Disposal Revenue Bonds (Pooled Series 1994A), and the Central Bank for Cooperatives (collectively, the "Financial Entities"). In the future, AEPCO may refinance such existing loans through new loans which will also be included in the "AEPCO Notes", as used in this Agreement.

G. The AEPCO Notes and certain of the loans made by, or securities issued to, or obligations undertaken to others (collectively, with the AEPCO Notes, the "Secured Obligations") are secured by a certain Consolidated Mortgage and Security Agreement dated as of June 14, 1989 made by and among AEPCO and RUS and CFC as amended and consolidated, or restated from time to time (the "AEPCO Mortgage").

H. This Agreement and the obligations hereunder and payments due to AEPCO under this Agreement are pledged and assigned to secure the Secured Obligations as provided in the AEPCO Mortgage.

I. RUS, CFC and the other holders of the Secured Obligations are relying on this Agreement and the obligations hereunder, and the Existing Wholesale Power Contracts and the obligations thereunder, to ensure the repayment of the Secured Obligations and to fulfill the purposes of the REAct. AEPCO and the Member, by

executing this Agreement, acknowledge such reliance and agree that RUS is a third party beneficiary of this Agreement and that this Agreement also operates for the benefit of RUS.

J. AEPCO and the Member recognize that the Existing Resources and transmission assets initially constructed or subsequently acquired and placed in service by AEPCO have served, on an integrated basis, the full electric requirements of AEPCO's Class A Members, including the Member, and the partial requirements of other wholesale customers of AEPCO. Commencing on the Effective Date, the servicing of the current and future electric loads of AEPCO, CSP and the Member; will be managed pursuant to the Resource Integration Agreement between CSP, AEPCO, TRANSCO and Member; the Transmission Agreement between TRANSCO and Member; certain agreements for transmission service between TRANSCO, the All Requirements Members and AEPCO, pertaining to the electric loads of the All Requirements Members; other arrangements for transmission service between AEPCO and TRANSCO pertaining to the electric loads of other wholesale customers of AEPCO; and arrangements for transmission service between TRANSCO and CSP, pertaining to the electric loads of CSP.

K. The Member has determined that its interests and the interests of its consumers will be best served by purchasing electric energy and capacity from AEPCO pursuant to the terms and conditions of this Agreement.

L. The Member agrees to purchase from AEPCO, and AEPCO agrees to sell to the Member, electric capacity, based upon the Allocated Capacity Percentage (the "ACP") of Member, and associated energy during the term of this Agreement on the terms and conditions herein set forth.

## AGREEMENT

NOW, THEREFORE, in consideration of the premises and the mutual undertakings contained herein, the Parties agree as follows:

1. DEFINITIONS.

All capitalized terms used and not defined herein shall have the respective meanings as set forth in Appendix A, and are defined solely for use with this Agreement, Rate Schedule A, and Schedule B.

1.1 "AEPCO's Member Peak Demand" shall mean the highest thirty (30) minute integrated demand in kW experienced during the billing period of the aggregate demands of all Class A Members purchased pursuant to this Agreement and the Existing Wholesale Power Contracts.

1.2 "AEPCO's Revenue Requirement" shall mean the total revenues, from any source whatsoever, necessary to enable AEPCO, utilizing a twelve month test period to: (i) meet all its anticipated fixed, variable, fuel, and all other costs, obligations and expenses and payments (including all payments on account of Indebtedness of AEPCO); (ii) establish and maintain reasonable financial reserves; and, (iii) add appropriate levels of margins and working capital to satisfy, at a minimum, applicable prescribed annual coverage ratios or any other financial covenants or tests imposed by the Financial Entities, as may exist from time to time.

1.3 "AEPCO's Revenue Requirement From AEPCO Class A Members" shall mean AEPCO's Revenue Requirement less revenues anticipated to be received by AEPCO from all sources other than the AEPCO Class A Members.

1.4 "AEPCO's Revenue Requirement From Partial Requirements Member" shall mean that portion of AEPCO's Revenue Requirement From AEPCO Class A Members allocated to a Partial Requirements Member as developed in accordance with Section 5 herein and Section 3 of Rate Schedule A.

1.5 "Demand Overrun Adjustments" shall have the meaning set forth in Section 2.2 of Rate Schedule A.

1.6 "Fixed Charge" shall mean the charge computed in accordance with Sections 5.2 and 5.3 herein which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

1.7 "Long Term Debt" shall have the meaning given in accordance with Accounting Requirements.

1.8 "MEC AEPCO Load" shall mean, the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within the Member's Distribution Service Area of MEC (or served from line extensions therefrom) for which MEC purchases capacity and energy pursuant to the Partial Requirements Capacity and Energy Agreement, but shall not include MEC Wheeling Load. Such demand and energy requirements are included within MEC Metered kW and MEC Metered kWh. The demand component of MEC AEPCO Load numerically consists of the coincident aggregate, at a specific time, of: (i) MEC Metered kW; less (ii) kW of MEC Wheeling Load; less (iii) kW of Member JMP Load of MEC; less (iv) kW of CSP JMP Load of MEC; less kW of MEC Internal Load. The energy component of MEC AEPCO Load numerically consists of the aggregate during a specific time interval of: (i) MEC Metered kWh; less (ii) kWh of MEC Wheeling Load; less (iii) kWh of Member JMP Load of MEC; less (iv) kWh of CSP JMP Load of MEC; less, (v) kWh of MEC Internal Load.

1.9 "Member Billing Demand" shall mean, as to Member, the demand of Member in kW integrated over the thirty (30) minute period occurring coincident in time with the AEPCO Member Peak Demand purchased by Member from AEPCO pursuant to this

Partial Requirements Capacity and Energy Agreement which consists of the demands of MEC AEPCO Load and MEC AEPCO Sales.

1.10 "Member Billing Energy" shall mean the energy in kWh received by MEC from AEPCO during the billing period pursuant to this Partial Requirements Capacity and Energy Agreement which consists of the energy requirements of MEC AEPCO Load and MEC AEPCO Sales.

1.11 "MEC AEPCO Sales" shall mean the demand and associated energy requirements, including any distribution losses and not including reserves or transmission losses, of those sales of MEC to wholesale buyers or end use loads which are external to Member's Distribution Service Area for which MEC purchases capacity and energy pursuant to the Partial Requirements Capacity and Energy Agreement. The demand and energy requirements of MEC AEPCO Sales shall be metered (or determined) as agreed between MEC and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery.

1.12 "MEC Metered kW" shall mean the demand in kW received at the Delivery Points of MEC as measured and recorded during the billing period by revenue quality meters installed at or used in conjunction with such Delivery Points. During each billing period, MEC Metered kW consists of the integrated demands of: (i) MEC AEPCO Load; (ii) MEC Wheeling Load; (iii) Member JMP Load of MEC; (iv) CSP JMP Load of MEC; and, (v) MEC Internal Load.

1.13 "MEC Metered kWh" shall mean the total energy in kWh delivered to the Delivery Points of MEC during the billing period, as measured and recorded for such billing period by revenue quality meters installed at or used in conjunction with such Delivery Points. During each billing period, MEC Metered kWh consists of the kWh of energy, as measured at the Delivery Points, consumed by: (i) MEC AEPCO Load; (ii) MEC Wheeling Load; (iii) Member JMP Load of MEC; (iv) CSP JMP Load of MEC; and, (v) MEC Internal Load.

1.14 "Power Factor Adjustment" shall have the meaning set forth in Section 2.2 of Rate Schedule A.

1.15 "Proposal and Analysis" shall have the meaning set forth in Section 3.4.3 herein.

1.16 "Required Modification" shall have the meaning set forth in Section 3.3.2 herein.

## 2. PURCHASE, SALE AND PAYMENT OBLIGATIONS.

### 2.1 Purchase and Sale.

2.1.1 AEPCO shall sell to the Member, and Member shall purchase from AEPCO, electric energy and capacity (at rates set forth in Exhibit A-1 to Rate Schedule A) scheduled by the Member or its scheduling agent, up to the

Member's Allocated Capacity (the "AC"), as determined by the ACP of Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A and the available AEPCO Resources as set forth in Appendix B to Exhibit A-5 to Rate Schedule A, for delivery to the Member at the point or points of delivery in accordance with Section 6 of this Agreement.

2.1.2 The Member shall take and pay, or pay for such electric energy and capacity under the terms and conditions set forth in this Agreement at rates and charges established pursuant to Section 5 of this Agreement and Rate Schedule A. The Member's payment obligations associated with its ACP in any AEPCO Resource allocated in accordance with this Agreement shall survive and continue until all of Member's payment obligations for such AEPCO Resource are paid in full to AEPCO notwithstanding the occurrence of any event, or the taking of any action permitted or contemplated by this Agreement, with respect to such AEPCO Resource, including, without limitation, any event or action described in Section 2.6.

2.1.3 AEPCO shall sell to Member and Member shall purchase from AEPCO levels of energy set forth in Schedule B.

2.2 AEPCO Obligation to Provide Electric Service. In the event that Resources of AEPCO in which the Member has been assigned an ACP and AC are unavailable to deliver electric energy and capacity to which the Member is entitled hereunder, AEPCO shall be responsible for obtaining electric energy and capacity from other sources in order to assure that Member's schedule is met.

2.3 No Dedication of Resources. The establishment of an ACP for the Member with respect to an AEPCO Resource or the sale by AEPCO to the Member of electric energy and capacity under this Agreement shall not constitute: (i) a sale, lease, transfer, dedication or conveyance of any ownership interest whatsoever in or to any specific AEPCO Resource nor (ii) an entitlement to the electric energy or capacity from any specific AEPCO Resource. AEPCO shall have the sole and unlimited authority, which it may exercise in its sole discretion, to manage, control and operate all of its Resources consistent with AEPCO's obligations to provide electric energy and capacity to the Member pursuant to this Agreement.

2.4 Power Factor on the Resources of AEPCO. The Member shall maintain Power Factor as close to unity as possible. Member shall pay AEPCO a power factor adjustment in accordance with Rate Schedule A in the event that the Power Factor of the Member is not within the limits set forth therein.

2.5 (Left intentionally blank.)

2.6 Member's Unconditional Obligation to Pay.

2.6.1 The Member shall have an unconditional obligation to make all payments to AEPCO required hereunder at the rates and Fixed Charge and on the terms and conditions set forth herein and in Rate Schedule A. The Member shall make all payments of Fixed Charges and of O&M charges and energy charges for capacity and energy provided for, under this Agreement, including without limitation, rates and Fixed Charges resulting from all Required Modifications and Minor Resource Modifications, as the case may be, in a timely manner whether or not any of the following conditions, as applicable, occur: (i) electric energy and capacity has been or is being provided to the Member hereunder; (ii) AEPCO Resources or any part thereof are completed, delayed, terminated, available, operable, operating, retired, sold, leased, transferred, or otherwise disposed of; (iii) the construction or operation of the AEPCO Resources or any part thereof is suspended, interrupted, interfered with, abrogated, reduced, curtailed or terminated; (iv) AEPCO is able to purchase or otherwise obtain electric energy and capacity from any other source; (v) any similar contract with another Member of AEPCO is invalidated; or (vi) any other contract between the Member, AEPCO, TRANSCO or CSP is invalidated, in any such case for any reason whatsoever and whether or not due to the conduct, acts or omissions of AEPCO. Payments by the Member hereunder, and the obligation to pay, shall be absolute and unconditional and shall not be subject to any reduction, whether by offset, set-off, recoupment or otherwise, and shall not be conditioned upon performance or limited by any Class A Member under any other wholesale power sales, power purchase or power marketing agreements entered into by AEPCO.

2.6.2 This Section 2.6 shall not be construed to release AEPCO from the performance of any of its obligations established in this Agreement or, except to the extent expressly provided in this Agreement, prevent or restrict the Member from bringing suit for enforcement of, or damages arising from, any rights that it may have against AEPCO under this Agreement or under any provision of Law, and to compel AEPCO to pay any damages awarded by a court of competent jurisdiction as awarded in a final judgment.

2.7 Disputed Bill. In the event that Member disagrees with a bill from AEPCO, the Member shall pay the bill in full within ten (10) business days and within five (5) business days after such payment provide AEPCO with written notice that the Member disputes the bill and the reasons for such dispute. AEPCO shall notify Member of its response to such written notice within ten (10) business days thereafter. If AEPCO agrees with Member, it shall amend the bill to reflect the correction within ten (10) business days after AEPCO's agreement and refund the overpayment plus interest from the date paid by the Member to the date of the repayment to the Member at the Contract Rate of Interest. In the event that AEPCO does not agree with the Member, the Authorized Representatives of the Parties shall

attempt to resolve the matter through negotiations. In the event that the Authorized Representatives are unable to reach an agreement within forty (40) days after Member's notice of dispute, the Member may refer the matter to binding arbitration or may seek resolution of such dispute in a court of competent jurisdiction.

3. PLANNING AND RESOURCE ALLOCATIONS AND MODIFICATIONS.

3.1 Resource Planning.

3.1.1 AEPCO shall not be responsible for and Member shall not be charged for: (i) bulk power supply planning, or (ii) any Future Resource procurement services (both services, collectively referred to as "Planning Services") for the Member, except pursuant to separate written agreements for such Planning Services executed by the Member and AEPCO. If the Member contracts separately to obtain Planning Services from AEPCO, it shall be referred to as a "Planning Contract Member".

3.1.2 Unless and until the Member becomes a Planning Contract Member, performing or obtaining Planning Services shall be the sole responsibility of Member and not AEPCO.

3.2 Allocated Capacity Percentage:

3.2.1 Allocated Capacity Percentage (ACP). AEPCO shall at all times maintain the Exhibits to Rate Schedule A which identify all AEPCO Resources, and the ACP and AC allocated to the Member and all other Class A Members with respect to each AEPCO Resource, by month, for the original projected useful life or for the contract term of each AEPCO Resource. AEPCO shall at all times also maintain current Tables and Exhibits to Schedule B. AEPCO shall provide copies of any revised Exhibits and Tables to Member at least fifteen (15) business days before such revisions become effective.

3.2.2 Future Resource. Unless the Parties agree by separate written agreement to establish an ACP for Member in a Future Resource, the Member shall not be charged by AEPCO for any costs directly or indirectly resulting from such Future Resource, and shall have no obligation or responsibility for repayment of the costs or charges of such Future Resource.

3.3 Change of Certain Member Obligations:

3.3.1 Subject to Section 5.6 hereof and Section 3 of Rate Schedule A, the Member's obligations shall be subject to certain changes as follows:

3.3.1.1 Except as provided in Section 3.3.1 below, AEPCO may not, in the case of a modification of a Resource in which Member has an ACP, without the prior written consent of the Member: (i) determine and modify the AC of Member in an Existing Resource; (ii) otherwise add or modify an Exhibit to Rate Schedule A; or (iii) modify any other

provision of this Agreement, each of which might be required as a result of such Resource Modification.

3.3.1.2 AEPCO may, in the case of a Minor Resource Modification, a Required Modification, or a modification made pursuant to Section 3.5 hereof, without the prior written consent of Member determine and modify the AC of Member in an Existing Resource in accordance with this Section 3 and otherwise add or modify Tables and Exhibits to Rate Schedule A and Schedule B as may be required as a result of any such modification.

3.3.1.3 AEPCO may, in the case of a Resource Modification in which Member has elected not to participate, without the prior written consent of the Member, determine and modify the ACP of Member in such Existing Resource and otherwise add or modify Tables and Exhibits to Rate Schedule A and Schedule B as may be required as a result of such Resource Modification to reflect the revised cost responsibility resulting from such Resource Modification.

3.3.2 AEPCO shall undertake from time to time expenditures for Resource Modifications required to comply with any Legal Requirement or as recommended by an engineering analysis that such a proposed modification is necessary for the safe and reliable functioning of the Resource ("Engineering Analysis Requirement"), both as determined by AEPCO ("Required Modification"). AEPCO shall submit to the Members written notification of its decision to undertake, and reasons for, a Required Modification within ten (10) business days after such determination by AEPCO. Member may dispute such determination either as to the requirement for the Required Modification or as to the modification proposed, or both. If the Member disputes only the determination that the Required Modification is a Legal Requirement, or an Engineering Analysis Requirement, the Member may refer such matter to binding arbitration under the Rules of the American Arbitration Association and substantive law within fifteen (15) business days of its receipt of notice of AEPCO's decision to undertake the Required Modification. If the Member disputes that the modification proposed by AEPCO is cost justified, Member shall, within forty-five (45) days, provide a more cost-effective alternative plan to AEPCO. If AEPCO has not accepted Member's proposed alternative plan in writing within forty-five (45) days of its receipt, Member may within fifteen (15) business days refer such matter to binding arbitration as set forth above. In the event Member disputes both the requirement for the Required Modification and the modification proposed, Member shall wait until AEPCO has had a forty-five (45) day opportunity to accept Member's alternative plan before referring such questions to arbitration as provided above. The only issues to be decided by arbitration, unless otherwise agreed by the Parties, shall be: (i) whether the proposed Required Modification was

necessary to comply with a Legal Requirement or Engineering Analysis Requirement, and/or (ii) whether the Member's alternative plan for the proposed Required Modification was the more cost-effective proposal consistent with Prudent Utility Practice. In the event that the decision rendered in such arbitration is that the Required Modification was necessary to comply with a Legal Requirement or Engineering Analysis Requirement, and the proposed Required Modification was the more cost effective alternative consistent with Prudent Utility Practice to comply with such Legal Requirement or Engineering Analysis Requirement, AEPCO may proceed with the Required Modification and modify the AC of the Member. If the arbitration decision is that the proposed Required Modification was not required to comply with a Legal Requirement or Engineering Analysis Requirement or that the proposed Required Modification was not the more cost-effective alternative consistent with Prudent Utility Practice to comply with such Legal Requirement or Engineering Analysis Requirement, the Member shall not be assessed any of the costs in its rates, charges or adjustments directly related to such Required Modification. The arbitration decision undertaken in accordance with this Section 3.3.2 shall be final and binding on the Parties, and non-appealable. The arbitration decision shall assess to the non-prevailing Party all expenses and costs, of whatsoever nature, including reasonable attorneys and consultants fees and the costs of arbitration, incurred by the prevailing Party as a result of the arbitration or caused as a consequence of any delay by AEPCO in complying with the Legal Requirement or Engineering Analysis Requirement (if AEPCO is the prevailing Party), and judgment on the award rendered may be entered in any court having jurisdiction thereof. The assessment to such non-prevailing Party shall be paid within thirty (30) days after such arbitration decision is rendered.

3.4 Resource Modifications.

3.4.1 The Member shall have an unconditional obligation to make all payments to AEPCO in accordance with Rate Schedule A to meet the costs, obligations and expenses associated with a decision of AEPCO to undertake a capital expenditure in accordance with this Section 3.4; unless the provisions of Section 3.4.7 apply to Member.

3.4.2 This Section 3.4.2 shall apply to Minor Resource Modifications and Resource Modifications as follows:

(a) Minor Resource Modifications. AEPCO may, in its sole discretion, undertake, from time to time, expenditures for additions, improvements, repairs or modifications to a Generating Resource or modify or extend the term of a Power Purchase Resource for five (5) years or less which, in either case, shall not: (i) increase the capacity of the AEPCO Resource being modified by greater than ten percent (10%); (ii) result in an increase of greater than five percent (5%) in

AEPCO's Revenue Requirement from AEPCO Class A Members upon the operation of such addition, improvement, repair or modification, or extension, as the case may be; or (iii) extend the term of this Agreement. Any expenditure undertaken by AEPCO under this Section 3.4.2(a) shall be a "Minor Resource Modification".

(b) Resource Modifications. AEPCO may propose to undertake, from time to time, Resource Modifications.

3.4.3 Proposal and Analysis. Except with respect to any Required Modification or Minor Modification, AEPCO shall submit to the Member a document with respect to any proposed Resource Modification ("Proposal and Analysis") containing: (i) the reasons therefor; (ii) the expected benefits and the estimated cost of implementing the proposal, demonstrating a positive benefits-to-costs relationship; (iii) the effect of implementing the proposal on the Member's AC and ACP, energy and cost; and (iv) an analysis of whether the period of AEPCO Indebtedness or the term of this Agreement will be extended to fund such proposed Resource Modification. The Proposal and Analysis shall be submitted to the Member and the time periods referred to in Section 3.4.4 shall have expired prior to the submittal of the proposed Resource Modification which is the subject of the Proposal and Analysis to the AEPCO Board of Directors.

3.4.4 Proposal and Analysis Review.

(a) Member shall notify AEPCO within thirty (30) business days of its receipt of any Proposal and Analysis whether Member consents to the proposed Resource Modification or that Member (i) disagrees with the Proposal and Analysis with the reasons for such disagreement; or (ii) requires additional analysis to more fully understand such Proposal and Analysis.

(b) Upon receipt from Member of a notice of disagreement with any Proposal and Analysis or a request for further analysis, AEPCO shall prepare and submit to Member, within thirty (30) business days thereafter, a response to such disagreement or such request for additional analysis. AEPCO's response shall reflect the costs and benefits of the proposed Resource Modification to all Class A Members and demonstrate an aggregate positive benefit-to-cost ratio to the Class A Members.

(c) If Member believes that the correct benefit-to-cost ratio of such proposed Resource Modification is not positive, then Member shall provide to AEPCO within thirty (30) business days of its receipt of AEPCO's response under Section 3.4.4(b) above a writing: (i) setting forth its analysis of the benefit-to-cost ratio of the proposed Resource

Modification and (ii) proposing any compromise which will, in its judgment, bring the proposed costs and benefits into balance for the Class A Members collectively. Member and AEPCO shall then enter into good faith negotiations to resolve their differences respecting such proposed Resource Modification.

(d) All activities contemplated by this Section 3.4.4 shall be concluded no later than one hundred twenty (120) days after the receipt by Member of any Proposal and Analysis which is the subject of dispute between the Parties. In the event that: (i) negotiations under Section 3.4.4(c) do not resolve the disagreement between the Parties with respect to a proposed Resource Modification; and (ii) the AEPCO Board of Directors approves any such Resource Modification pursuant to Section 3.4.5 hereof, then: (a) the AC of Member; (b) the term of this Agreement; or (c) the rates and Fixed Charge billed to Member may not be modified to provide for the collection of the costs, obligations or expenses for such Resource Modification, and Section 3.4.7 shall apply to Member. The ACP of Member may, however, be modified by AEPCO to maintain the AC of the Member in the Resource at the same level as its AC prior to the Resource Modification.

3.4.5 Project Approval. Any addition of, or modification to, an exhibit to Rate Schedule A as a result of: (a) a Resource Modification which is (i) a Generation Resource; or (ii) an extension of a then-existing Power Purchase Resource, with a new or extended term of greater than five (5) years; or (b) a modification which is not a Required Modification must, in either case, be approved by a majority vote of the AEPCO Board of Directors, including an affirmative vote of at least sixty-six and two-thirds percent (66 2/3%) of the directors representing the Class A Members prior to the AEPCO Board of Directors' authorization of the principal documents necessary to obligate AEPCO to a transaction resulting in such addition or modification to an exhibit to Rate Schedule A. Any such approval obtained pursuant to this Section 3.4.5 shall constitute a "Project Approval".

3.4.6 Member Approval. Following a Project Approval, the addition or modification specified in Section 3.4.5 hereof shall be submitted to Member for its written approval pursuant to this 3.4.6, unless the Member has previously given its requisite consent pursuant to Section 3.4.4. Such written approval of Member shall also constitute authority to make the necessary additions of, or modifications to, Rate Schedule A and Schedule B affecting Member's participation in the Resource Modification. Rate Schedule A and Schedule B shall accordingly be amended, as necessary, to reflect the addition of each Resource Modification. In the event Member consents in writing pursuant to Section 3.4.4 hereof or gives written approval within ten (10) business days after the submittal contemplated in this Section 3.4.6, the

Member shall make all payments required pursuant to Section 3.4.1 with respect to such addition or modification to Rate Schedule A and Schedule B, including without limitation, an extension of the term of this Agreement.

3.4.7 Member Disapproval. In the event that Member elects not to approve any addition or modification specified in Section 3.4.5 in accordance with Section 3.4.4 or Section 3.4.6 hereof, then Member shall notify AEPCO in writing of such election.

3.5 Modification of AC for Reserves and Losses:
In the event of: (i) a change in the reserve requirements which AEPCO is legally required to maintain, or (ii) an engineering study which is commissioned by TRANSCO demonstrates that the transmission loss percentage on the TTS needs to be changed in order to accurately reflect the actual losses on the TTS, AEPCO shall modify the AC of Member to reflect the AC available to Member after such change in reserve requirements or transmission losses. Such modified AC shall be effective as of the first billing period beginning no less than forty-five (45) days after Member has received notice of the modified AC.

4. RESOURCE POOL.

The Member shall include the electric capacity and energy to which it is entitled under this Agreement in the Resource Pool.

5. RATES AND CHARGES.

5.1 Billing and Payment. Electric capacity and energy furnished to Member pursuant to this Agreement shall be billed on a calendar month basis. AEPCO shall prepare monthly bills for electric capacity and energy service and send such bills by electronic transmission, with a copy placed in the U.S. Mail, return receipt requested, to the Member no later than the tenth (10th) business day of the following calendar month. Member shall pay AEPCO the total amount of such bill by the later of (a) the twentieth (20th) business day of the month that the bill is sent or (b) ten (10) business days after receiving the bill by the earlier of (i) electronic transmission or (ii) U.S. Mail. Member shall make payment by electronic wire transfer to a bank selected by AEPCO, or by any other method which provides Collected Funds to AEPCO on or before the payment due date. Amounts not paid by the due date shall be payable with interest accrued at the Contract Rate of Interest. Member shall make all payments to AEPCO that are required pursuant to this Agreement at the rates, Fixed Charge and other adjustments, and on the terms and conditions set forth herein and in Rate Schedule A, as amended from time to time, in accordance with Section 5.5 hereof. All such rates, Fixed Charge, and other such adjustments proposed or implemented by AEPCO shall be in accordance with the requirements of this Section 5, Section 8, Rate Schedule A and its obligations to the Financial Entities.

5.2 Fixed Charge. AEPCO shall charge, and the Member shall pay all fixed costs and expenses based on its ACP through the payment by the Member of an annual Fixed Charge as determined, and set forth in, and due and payable, pursuant to Rate Schedule A.

5.3 O&M Charge. AEPCO shall charge, and the Member shall pay all operations and maintenance costs and expenses based on its Member Billing Demand through payment by the Member of a monthly O&M charge as determined, and set forth in, and due and payable, pursuant to Rate Schedule A, and Schedule B if applicable.

5.4 Energy Charge. Subject to the minimum take obligations set forth in Section 2.4 hereof, AEPCO shall charge, and the Member shall pay, the cost of energy actually delivered to the Member in accordance with Section 6.1 hereof through payment by the Member of a monthly energy charge as determined, and set forth in, and due and payable, pursuant to Rate Schedule A.

5.5 Schedule B Charge. AEPCO shall charge, and the Member shall pay, the charges calculated under Schedule B if applicable.

5.6 Rate and Fixed Charge Design and Revision. At such intervals as AEPCO shall deem appropriate, but in any event not less frequently than once in each calendar year, AEPCO shall review the rates and Fixed Charge for electric energy and capacity provided hereunder and under the Existing Wholesale Power Contracts with AEPCO's All Requirements Members. If such rates or Fixed Charge are to be revised, AEPCO shall cause a notice in writing to be provided to the Member, other Class A Members of AEPCO, and the Administrator which notice shall set forth the proposed revisions of the rates or Fixed Charge with the effective date thereof, and the basis upon which the rates or Fixed Charge is proposed to be adjusted and set. The Member agrees that the rates and Fixed Charge from time to time set by AEPCO in Rate Schedule A shall be substituted for the rates herein provided and agrees to pay for electric energy and capacity provided by AEPCO hereunder after the effective date of any such revised rates and Fixed Charge; provided that no such revised rates or Fixed Charge shall be effective unless approved in writing by the Administrator. AEPCO shall design and set future rates and the Fixed Charge based on Rate Schedule A to produce revenues that shall be sufficient, but only sufficient, with the revenues of AEPCO from all other sources to satisfy all of AEPCO's Revenue Requirement which is developed to provide revenues sufficient to meet all of AEPCO's obligations, including, but not limited to:(i) all of AEPCO's costs, obligations, and expenses; (ii) all payments on account of Indebtedness of AEPCO, including Indebtedness to RUS and others; (iii) the establishment and maintenance of reasonable financial reserves; and (iv) all requirements, including financial covenants and tests contained in the AEPCO Mortgage, AEPCO Loan Contract or in any other indenture, mortgage, security agreement or contract relating to any Indebtedness, the Secured Obligations or any other financial obligations of AEPCO as any of the foregoing may exist from time to time.

5.7 Resource Pool Settlement. Credits and charges from settlements related to the pooled operation of AEPCO Resources, and any other income belonging to AEPCO derived from the sale or use of such AEPCO Resources, shall be reflected in the rates and Fixed Charge charged to the Member in accordance with Rate Schedule A.

5.8 Accounting for Costs. AEPCO shall account to the Member, in accordance with Accounting Requirements, for its direct and indirect costs for AEPCO Resources and for each service that AEPCO provides to the Member.

5.9 Reasonable Rates. The Parties agree that the rates, Fixed Charge, rate methodology, terms and conditions of service established hereunder are just and reasonable under the current circumstances and reflect their determination that any revisions, adjustments or changes to such rates or Fixed Charge established in accordance with this Agreement shall, in the future, be deemed just and reasonable and not unlawfully discriminatory under applicable Law. The rates and Fixed Charge take into account specific benefits achieved by the Parties through this Agreement and not otherwise available to the Parties, and reflect the sharing of those benefits without undue discrimination against any current or future customer or Member of AEPCO.

5.10 Covenant of the Member. The Member covenants and agrees to design, set and maintain its rates and charges at a level sufficient to collect payments for the service of its electric system, and to conduct its business in a manner which shall produce revenues and receipts at least sufficient to enable the Member to pay to AEPCO, when due, all amounts payable by the Member under this Agreement.

5.11 Cost Responsibility. The rates and charges and the Fixed Charge applicable to the Member pursuant to Exhibit A-1 to Rate Schedule A to meet the Revenue Requirement from Partial Requirements Member shall take into account all direct and indirect costs and revenues, including administration and general expenses, margins, revenues from the sale of electric energy, capacity and other services and investment gain and loss, allocated by AEPCO among the Existing Resources. Subject to Section 3.2.2, such rates and charges shall not take into account costs and revenues allocated by AEPCO to any Future Resource.

5.12 Recovery of Revenue Shortfall. AEPCO shall at all times design, set, maintain and collect payments on the basis of rates, a Fixed Charge and other adjustments to fully recover all costs, obligations and expenses, including, but not limited to, the occurrence of any Revenue Shortfall.

## 6. POINTS OF DELIVERY AND GENERAL TERMS AND CONDITIONS OF SERVICE.

6.1 Points of Delivery. Subject to Section 6.2, AEPCO shall furnish the electric capacity and energy purchased by the Member under this Agreement to the Member or the Member's transmission provider or agent for delivery to the Member at: (i) the low side of the step-up transformer at each Generating Resource of AEPCO with respect to electric energy and capacity that is produced by a Generating Resource of AEPCO

that is interconnected with the TTS; and (ii) for a Power Purchase Resource of AEPCO, the interconnection point with the TTS where AEPCO takes title to such electric energy and capacity; or (iii) the interface with the TTS at which capacity is provided and electric energy is delivered to AEPCO from an AEPCO Resource that is not interconnected with the TTS. Title and risk of loss of such electric energy and capacity shall pass from AEPCO to the Member or Member's transmission provider or agent at such points of delivery. As among the Parties hereto, AEPCO shall be deemed to be in exclusive control and responsible for transmission losses and any injury and damage caused by the electric energy and capacity prior to the point of delivery, and the Member shall be deemed to be in exclusive control and responsible for transmission losses and any damage or injury caused by the electric energy and capacity at and from the point of delivery.

6.2 AEPCO and Member Covenants and Member Representations.

6.2.1 AEPCO and the Member shall use their respective best efforts to cause a constant and uninterrupted supply of electric energy and capacity to be delivered and received.

6.2.2 AEPCO covenants and agrees that it will operate, maintain and manage its Resources in accordance with Prudent Utility Practice.

6.2.3 Member covenants and agrees that it will operate, maintain and manage its electric system in accordance with Prudent Utility Practice.

6.2.4 The Member's ACP as set forth in Exhibit A-5 to Rate Schedule A is accepted by the Parties. The Member's ACP was based on certain load forecasts established in the 1996 Power Requirements Study. The Parties agree that such Power Requirements Study is an acceptable basis upon which to establish Member's ACP and to apply such ACP for cost responsibility under this Agreement.

6.2.5 The Parties agree that the rates, Fixed Charge, methodology and principles of cost allocation set forth in this Agreement are just and reasonable.

6.3 Metering for Billing Purposes.

6.3.1 For the purposes of applying billing units to the rates determined pursuant to this Agreement as set forth in Rate Schedule A, Member shall arrange with Member's transmission provider(s) or agent pursuant to Section 6.1 to timely communicate to AEPCO, Member's monthly peak demand and energy consumption from revenue quality metering installed at the Member's Delivery Points. AEPCO shall provide electric energy and capacity to such transmission provider(s) to satisfy the demand and energy losses incurred in transmission of Member's electric energy and capacity hereunder, as such losses are incurred between Member's points of delivery as set forth in Section 6.1 and such locations where Member takes delivery from such transmission provider(s).

6.3.2 Member shall require its transmission provider(s) or agent, pursuant to Section 6.1, to test and calibrate such metering by comparison with accurate standards at intervals of twelve (12) months. Upon the request of AEPCO, Member shall further require such transmission provider(s) or agent to make special meter tests at any time. The costs of all such special tests at AEPCO's request shall be borne by AEPCO; provided, however, that if any special meter test made at AEPCO's request discloses that the meters are recording inaccurately, the Member shall reimburse AEPCO for the cost of such test. Meters registering not more than one percent (1%) above or below nominal shall be deemed to be accurate. The readings from any meter which shall have been disclosed by any test to be inaccurate shall be corrected in accordance with the percentage of inaccuracy found by such test for a period equal to the lesser of: (i) the period of the inaccuracy, if determinable by AEPCO in conjunction with the Member and the transmission provider(s), or (ii) three (3) months previous to the month of such test. If any meter shall fail to register for any period, AEPCO shall render a bill therefor based upon AEPCO's estimate of Member's demand and energy consumption, as applicable.

6.3.3 Member shall notify AEPCO in advance of the time of any special meter test requested by AEPCO so that AEPCO may send a representative to be present at such meter test.

6.3.4 Any corrections in billing resulting from metering inaccuracies shall be made in the next monthly bill. In the event that the Parties are unable to resolve their differences, AEPCO shall render a bill or offer a credit, as the case may be, and the Member shall dispute that bill or credit only pursuant to Section 19 hereof.

7. JOINT MARKETING AGREEMENTS.

AEPCO and the Member acknowledge that CSP and Member may enter into a mutually acceptable joint marketing agreement (Joint Marketing Agreement) in order to facilitate effective competitive retail electric sales of electric energy and capacity in the Member's Distribution Service Area.

8. STRANDED COST RECOVERY.

8.1 Stranded Cost Recovery. In the event the ACC permits the recovery by AEPCO or Member of any Stranded Costs by means of a surcharge, fee, wires charge or any other recovery mechanism charged to or assessed against the Member's distribution customers, the Member shall collect and remit to AEPCO all such funds collected by Member that represent recovery of AEPCO's Stranded Costs, including any such Stranded Costs associated with this Agreement.

8.2 Recovery of Stranded Costs by AEPCO. AEPCO shall diligently and vigorously pursue legal and administrative action to recover all of the Stranded Costs of AEPCO described in Section 8.1. The Member shall join with AEPCO in recovering such Stranded Costs and the Parties will cooperate fully in seeking such recovery.

8.3 Recovery of Stranded Costs by Member. In the case of Stranded Costs not covered by the preceding Section 8.2, if the Member seeks recovery of its Stranded Costs for its electric system on its own, AEPCO shall assist the Member and shall supply the Member with any information in the possession or control of AEPCO at Member's reasonable request.

9. AUTHORIZED REPRESENTATIVES.

Each Party shall designate within thirty (30) business days after the execution of this Agreement, by written notice to the other Party, a representative who is authorized to act on its behalf in implementation of this Agreement and with respect to those matters contained herein which are the functions and responsibilities of the Authorized Representatives, provided that the Authorized Representatives shall have no authority to modify this Agreement. Either Party may, at any time, change the designation of its Authorized Representative by written notice to the other Party.

10. COMMITTEES.

As a means of securing effective cooperation, and of dealing on a prompt and orderly basis with various technical and operating issues that may arise in connection with AEPCO system development or operations under changing conditions, the Parties will establish a standing operating committee charged with certain responsibilities (Operating Committee). The Parties may establish other such committees or work groups as may be determined by the Authorized Representatives. Each Party shall bear its costs related to its participation in the Operating Committee and other such committees or work groups. The responsibility and authority of each committee shall be limited to technical and operating matters in connection with the implementation of this Agreement and shall not extend to other affairs of the Parties.

11. RIGHTS OF ACCESS, RECORDS AND ACCOUNTS.

11.1 Rights of Access. Duly authorized representatives of either Party hereto shall be permitted to enter the premises of the other Party hereto at all reasonable times in order to implement this Agreement.

11.2 Accounting Records. AEPCO shall keep accurate records and accounts in accordance with Accounting Requirements. Promptly after the close of each fiscal year (and not later than 120 days after the end of each fiscal year), AEPCO shall cause such records and accounts of all transactions of AEPCO with respect to such fiscal year to be subject to an annual audit conducted in accordance with Accounting Requirements by a firm of independent certified public accountants experienced in electric utility accounting and possessing a national reputation in accounting and

auditing. AEPCO shall without delay provide a copy of each such annual audit, including all written comments and recommendations of such accountants to the Member and, so long as AEPCO is a borrower thereof, to RUS.

11.3 Access to Books and Records. The Member shall at all times have reasonable access during business hours to examine or audit any and all of the books, records and supporting worksheets and data of AEPCO, as may be appropriate, to determine the accuracy of any charges or payments required to be made by the Member to AEPCO. If such books, records and supporting worksheets and data of AEPCO contain information about another Member of AEPCO, AEPCO shall excise any identification of a specific Member or provide such information to the Member or its independent certified public accountant or other independent representative of the Member under a confidentiality agreement. If, after such examination or audit of AEPCO's records, there exists a dispute as to the accuracy of any charge and the Parties proceed to resolve such dispute under Section 19 hereunder, Section 22.5 hereof shall apply.

11.4 Materiality, Standards, Time Periods. Prior to any audit of AEPCO's records, AEPCO's internal auditor and the Member's auditor shall plan the examination's analytical procedure of the audit and shall agree on a materiality threshold for acceptable individual and accumulated misstatements (both over and under billings) of cumulative billing amounts. For purposes of this Section 11.4, "cumulative" shall mean the billing periods being audited. Any audit of AEPCO's records shall be made in accordance with Generally Accepted Auditing Standards and shall be limited to AEPCO's current and prior three (3) fiscal years.

## 12. REORGANIZATIONS, TRANSFERS AND SALES OF ASSETS BY THE MEMBER.

12.1 Dissolution or Liquidation. The Member shall not dissolve, liquidate or otherwise wind up its affairs without the separate approvals in writing of each of AEPCO and the Administrator while this Agreement remains in effect. In each such case, such approval shall not be unreasonably withheld.

12.2 Permitted Member Transactions. So long as this Agreement remains in effect, Member shall not, nor suffer any effort to, consolidate or merge with any other Person or reorganize or change the form of its business organization from an electric cooperative non-profit membership corporation or sell, transfer, lease or otherwise dispose of all or substantially all of its assets (each, a "Member Transaction") to any Person (or make any agreement therefor), whether in a single transaction or series of transactions, unless:

(a) Such Member Transaction is expressly approved in separate writings by AEPCO and the Administrator; provided that neither AEPCO nor the Administrator will withhold or condition its consent except in cases where to do otherwise would, in the determination of AEPCO or the Administrator, as applicable, result in rate increases for the other Class A Members of AEPCO;

impair the ability of AEPCO to satisfy the Secured Obligations in accordance with their terms; substantially increase AEPCO's capacity and energy sales requirements; or adversely affect system performance in any material manner; or

(b) All of the following conditions are satisfied:

(i) The Transferee shall be an entity organized and existing under the laws of the United States of America or any State or the District of Columbia; and

(ii) No default, breach or event which, with the lapse of time or the giving of notice, or both, could be expected to result in a breach, of this Agreement shall have occurred and be continuing; and

(iii) The Transferee shall execute and deliver to AEPCO an instrument supplemental hereto in form reasonably satisfactory to AEPCO containing an assumption by the Transferee of the performance and observance of every covenant and condition of this Agreement required to be performed or observed by the Member, and accepting and assuming all obligations and liabilities under this Agreement; and

(iv) A firm of independent certified public accountants shall prepare for the two calendar years immediately preceding the Member Transaction a set of pro forma financial statements that assume the consummation of the Member Transaction through the applicable determination period and that are prepared in accordance with Generally Accepted Accounting Principles. Based on such pro forma financial statements, such accountants must certify that:

(A) the Transferee's Debt Service Coverage Ratio is at least a level of 1.25 and Times Interest Earned Ratio is at least a level of 1.50 for each of the two immediately preceding calendar years (assuming such Member Transaction had been consummated at the beginning of such two-year period);

(B) the Transferee's Equity equals at least 32% of its Total Assets after giving effect to such Member Transaction; and

(C) the ratio of the Transferee's Net Utility Plant to its Long-Term Debt is at least a level of 1.0 after giving effect to such Member Transaction.

The specification of conditions in Section 12.2(b) shall not be construed to establish standards under which the Member may effect a Member Transaction. The purpose of such conditions is to establish when approval by AEPCO or the Administrator need not be obtained.

12.3 Service Territory and Electric System. The Member shall not voluntarily convey, transfer, lease, or otherwise dispose of any part of its electric system or assigned service territory or voluntarily transfer or assign to another Person any customer of the Member (each, a "Conveyance") if such Conveyance, considered together with: (i) all prior Conveyances, and (ii) all prior additions (by construction, conveyance, transfer or lease to the Member) to its electric system, assigned service territory or customers, could reasonably be expected to have a material adverse affect on the Member's ability to perform its obligations under this Agreement.

13. ASSIGNMENTS.

13.1 General.

13.1.1 Except as otherwise set forth in this Section 13, this Agreement shall be binding upon and inure to the benefit of the permitted successors and permitted assigns of the Parties. This Agreement may not be assigned by either Party unless prior consent to such assignment is given in writing by (i) the other Party, which consent shall not be unreasonably withheld and (ii) the Administrator, in its sole discretion, if either Party is then a RUS borrower. Any assignment made without a consent required hereunder shall be void and of no force or effect as against the non-consenting Party or RUS, as the case may be.

13.1.2 No sale, assignment, transfer or other disposition permitted by this Agreement shall effect, release or discharge either Party from its rights or obligations under this Agreement, except as may be expressly provided by this Agreement.

13.2 Assignment for Security.

13.2.1 Notwithstanding any other provision of this Agreement, a Party, without the other Party's consent, (but if such assigning Party is a borrower of RUS, then only with the consent of the Administrator) may enter into an Assignment for Security for any obligation secured by any indenture, loan contract, mortgage, financial instrument or similar lien on its system assets. Such Assignment for Security shall be without limitation on the right of the secured party to further assign this Agreement, including, without limitation, the assignment by the Member or AEPCO to create a security interest for the benefit of RUS, or for the benefit of any third party with the consent of the Administrator, if such assigning Party is a borrower of RUS.

13.2.2 The Parties acknowledge that, as a permitted assignee through an Assignment for Security, the Administrator or other secured party, without the approval of the other Party to this Agreement, may: (i) cause this Agreement to be sold, assigned, transferred or otherwise disposed of to a third party pursuant to the terms governing an Assignment for Security; or (ii) sell, assign, transfer or otherwise dispose of this Agreement to a third party (if RUS or

other secured party first acquires this Agreement); provided, however, that in either case the Party who made the Assignment for Security is first in default of its obligations to RUS or other secured party that is secured by such security interest.

13.3 Corporate Reorganization by AEPCO.

13.3.1 Subject to the prior written approval of the Administrator while AEPCO is a RUS borrower, AEPCO may assign any or all of its rights and delegate any or all of its duties under this Agreement in connection with any reorganization, merger or consolidation of AEPCO with another entity in which AEPCO is not the surviving entity.

13.3.2 Subject to the prior written approval of the Administrator while AEPCO is a RUS borrower, AEPCO may, in its sole discretion, at any time and from time to time, retire, sell, transfer, lease, terminate or otherwise dispose of any AEPCO Resource (even though such transaction may reduce or eliminate the electric energy and capacity available to the Member with respect to such Resource), subject to the provisions of Sections 2.1 and 2.2 of this Agreement.

13.4 Receiver or Trustee in Bankruptcy. The Parties intend that the rights and obligations of the Member under this Agreement shall not be affected by a receiver, a trustee in bankruptcy, a mortgagee or an indenture trustee assuming control of the assets or business of AEPCO, and that such receiver, trustee, mortgagee or indenture trustee may exercise all of the rights of, and shall meet all the obligations, including those to the Member, and make all of the determinations provided to be made in this Agreement by the AEPCO Board of Directors or AEPCO, as the case may be.

13.5 Express Rejection of Implied Limitations. The Parties intend that this Agreement shall be assignable by AEPCO in accordance with the provisions of this Section 13 without regard to any other provisions of this Agreement, the nature of the Person to whom this Agreement is assigned, or the issues raised in the case, *In the Matter Of Wabash Valley Power Assn., Inc.*, 72 F.3d 1305 (7th Cir. 1995); provided that the assignee in any assignment (other than an Assignment for Security) shall at the time of such assignment deliver to the Class A Members, including Member, a written assumption of AEPCO's obligations and liabilities pursuant to this Agreement. The Parties agree that this Agreement may be assigned by AEPCO to any Person (including any receiver or trustee in bankruptcy) pursuant to this Section 13 without regard to the fact that: (i) such Person is not a cooperative; (ii) the Board of Directors of such Person, if any, is not chosen by a vote in which the Member participates; or (iii) such Person is not operated on a not-for-profit basis. Further, no other provision of this Agreement shall restrict the assignment of this Agreement by AEPCO pursuant to this Section 13.

14. EVENTS OF DEFAULT AND REMEDIES.

14.1 Payment Default. If the Member fails to make full payment to AEPCO when required to be made under this Agreement, and such failure continues for a period of five (5) business days, AEPCO shall give written notice to the Member. If the Member does not, within ten (10) business days from the date of the receipt of such notice, pay the full outstanding amount then due to AEPCO, together with interest thereon computed at the Contract Rate of Interest, such failure shall constitute a "Payment Default" on the part of the Member. AEPCO shall promptly provide written notice to the other Class A Members of the Payment Default. The amount of any such payment not paid in full when due shall thereafter accrue an interest charge at the Contract Rate of Interest.

14.1.1 Upon a Payment Default, AEPCO may, upon twenty-four (24) hours prior written notice, suspend service to the Member for the period of the continuing Payment Default. AEPCO's right to suspend service shall not be its sole and exclusive remedy, but shall be in addition to all other remedies available to AEPCO at law or in equity. No suspension of service under, or termination of, this Agreement or recovery of additional revenues from other Members of AEPCO shall relieve the Member of its obligations or outstanding liability for any amount owed by it to AEPCO hereunder, which are absolute and unconditional. AEPCO shall make reasonable efforts to mitigate the expense to Member by marketing at commercially reasonable prices the capacity and energy whose delivery to the Member under Section 6.1 hereof has been suspended; provided the Member shall have a continuing obligation to make all payments to AEPCO required to be made pursuant to this Agreement. AEPCO shall credit the obligations of the Member during any suspension of service with the monies actually received by AEPCO from sales of capacity and energy (less any damages attributable to the Payment Default and all costs and expenses of re-marketing such capacity and energy) that would have been available to serve the Member; provided that AEPCO, in absence of gross negligence or willful misconduct, shall not be responsible to Member for failure to otherwise mitigate the consequences of the Member's Payment Default.

14.1.2 AEPCO may terminate this Agreement if a Payment Default shall have occurred and is continuing.

14.1.3 AEPCO shall commence such suits, actions or proceedings, at law or in equity as may be necessary or appropriate to enforce the obligations of the Member under this Agreement.

14.2 AEPCO's Failure to Deliver. As provided for in Section 2.6 and except as provided in Section 22.2 hereof, if AEPCO fails to provide electric energy and capacity as required by Section 2.2 hereof, AEPCO shall promptly provide notice to Member upon learning of a failure to deliver electric energy and capacity services and use its best efforts to restore service to Member. If AEPCO is unwilling to restore or

provide substitute service pursuant to Section 2.2 hereof, AEPCO shall reimburse the Member for the reasonable direct and verifiable costs incurred by Member to obtain and replace such electric energy and capacity that AEPCO was unwilling to restore or provide, but the Member shall not be entitled to terminate this Agreement or to withhold payments required to be made pursuant to this Agreement.

14.3 Performance Default. If either Party fails materially to comply with any of the terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default by the Member or a failure to deliver as set forth in Section 14.2), the non-defaulting Party shall give the defaulting Party written notice of the default (Performance Default). The defaulting Party shall have a period of ten (10) business days after receipt of such notice to cure such Performance Default; provided, however, that in the event the nature of the default is such that it can be cured but cannot reasonably be cured during such ten (10) business day period, the defaulting Party shall not be deemed in default so long as the defaulting Party promptly commences to remedy the default and diligently prosecutes such remedy to completion. In the event that the defaulting Party does not cure such Performance Default as herein provided, the non-defaulting Party, subject to Section 14.4.3, shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement.

14.4 Remedies.

14.4.1 Notwithstanding any provision to the contrary set forth in the AEPCO restructuring, the Parties do not intend that their respective rights and obligations arising under this Agreement as a factual matter shall be deemed special, unique and extraordinary in nature.

14.4.2 Every right, obligation and remedy of a Party may be exercised concurrently, or separately, from time to time, and so often and in such manner as may be deemed expedient by the exercising Party, and the exercise of any such right, obligation and remedy shall not be deemed a waiver of the right to exercise at the same time or thereafter, any other right, obligation or remedy.

14.4.3 No remedy conferred upon or reserved by AEPCO or the Member under this Agreement is intended to be exclusive of any other remedy or remedies available hereunder or now or hereafter existing; provided that no Performance Default by AEPCO shall permit the Member to terminate this Agreement or relieve the Member of its obligation to make payments pursuant to this Agreement, which obligation shall be absolute and unconditional and no default other than a Payment Default shall relieve AEPCO of its obligation to deliver the Member's allocated capacity and associated energy in accordance with Sections 2.2 and 6 hereof.

14.4.4 No waiver by either Party hereto of any one or more defaults by the other Party hereto in the performance of any provision of this Agreement shall be

construed as a waiver of any other default or defaults, whether of a like kind or different nature.

14.4.5 AEPCO and the Member agree for their benefit and that of RUS that: (a) if the Member fails to comply with any provision of this Agreement, AEPCO and the Administrator shall have the right to enforce the obligations of the Member under this Agreement and (b) if AEPCO shall fail to comply with any provision of this Agreement, the Member or the Administrator shall have the right to enforce the obligations of AEPCO under this Agreement. Such enforcement may be through the instituting of all necessary actions at law or suits in equity, including, without limitation, suits for specific performance. Such rights of the Administrator to enforce the provisions of this Agreement are in addition to and shall not limit the rights which RUS shall otherwise have as third party beneficiary of this Agreement or pursuant to the assignment and pledge of this Agreement and the payments required to be made hereunder as provided in the AEPCO Mortgage.

14.4.6 The rights of RUS under this Agreement shall terminate when AEPCO is no longer a borrower of RUS.

15. EFFECTIVENESS AND TERM.

This Agreement is dated as of the date of execution and shall become effective upon the Effective Date and, unless terminated by AEPCO in accordance with Section 14.1.2, shall remain in effect until December 31, 2020, unless extended further pursuant to Sections 3.3 and 3.4 hereof or by the written notice of Member. After December 31, 2020 (or such date to which the term hereof may have been extended), the Parties will enter into negotiations to determine their future relationship, if any, recognizing the past revenue payment which Member has made in support of the AEPCO Resources.

16. AMENDMENTS, CONFLICTS, AND COUNTERPARTS.

16.1 Amendments.

(a) Except as provided in Sections 16.1(b) and (c) below, no amendment to this Agreement shall be effective unless: (i) such amendment is in writing; (ii) executed by both Parties; and (iii) reviewed and approved in writing by the Administrator.

(b) No amendment to the rate-setting methodology of Rate Schedule A governing Existing Resources shall be effective unless: (i) approved by both Parties and by all other Class A Members; and (ii) reviewed and approved in writing by the Administrator.

(c) No amendment to Exhibits A-1, A-3 (as required by Accounting Requirements) or A-5 pursuant to Sections 3.3, 3.4 or 3.5 above to Rate Schedule A or Schedule B or any other Exhibit or schedule hereto shall be

effective unless approved by the AEPCO Board of Directors, and reviewed and approved in writing by the Administrator.

16.2 Entire Agreement. This Agreement constitutes the entire agreement between the Parties relating to the subject matter of this Agreement and supersedes all previous agreements, whether oral or written, including without limitation, the Existing Wholesale Power Contract between AEPCO and Member. A copy of the Member Agreement is attached hereto as Attachment A for the sole limited purpose of providing information involving Member related to the restructuring of AEPCO and is not incorporated into this Agreement by reference thereto. Rate Schedule A and Schedule B are incorporated herein by reference and all amendments thereto approved under Section 16.1 hereof shall be attached hereto and thereby incorporated herein.

16.3 Conflicts.

16.3.1 In the event of any conflict between the provisions of this Agreement and any other agreement between the Parties, the provisions of this Agreement shall govern.

16.3.2 In the event of any conflict between the provisions of Sections 1 through 22, inclusive, of this Agreement and the provisions of Rate Schedule A or of any amendments to Rate Schedule A or any future exhibits, appendices or schedules attached thereto, the provisions of Sections 1 through 22, inclusive, of this Agreement shall govern.

16.4 Counterparts and Facsimile Delivery. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Any Party may deliver an executed copy of this Agreement and an executed copy of any other document contemplated hereby by facsimile transmission to the other Party, so long as subsequently confirmed in the manner set forth in Section 21, and such delivery shall have the same force and effect as any other delivery of a manually signed copy of this Agreement or such other document. Each Party and RUS shall receive and retain one counterpart with original signatures of the Parties and shall provide a copy thereof to the other Party or RUS upon request.

17. SEVERABILITY.

If any part or any provision of this Agreement shall be held invalid or unenforceable by any Governmental Authority having jurisdiction under applicable Law, said part or provision shall be ineffective only to the extent of such invalidity without in any way affecting the remaining parts of said part or provision or the remaining provisions of this Agreement. In the event that such invalidity alters the relationship of the Parties to the significant disadvantage of a Party, the Parties shall attempt to negotiate a modification of the terms of the Agreement in order to reestablish the original balance of benefits, and if such agreement

is not reached, the disadvantaged Party may seek reformation of the Agreement through the dispute resolution process provided in Section 19 herein.

18. GOVERNING LAW.

Except to the extent governed by applicable federal Law, this Agreement shall be governed by, and construed in accordance with, the Laws of the State of Arizona, without giving effect to its conflicts of law principles.

19. DISPUTE RESOLUTION.

19.1 Dispute Resolution Committee. Upon a dispute arising between the Parties, AEPCO and the Member shall each designate one representative to serve on a Dispute Resolution Committee which shall be assigned disputes or matters for resolution by the Authorized Representatives of AEPCO and the Member.

19.2 Mediation. Except as otherwise provided herein, the Parties shall first in good faith seek to resolve any dispute arising hereunder through negotiation. If such dispute cannot be settled through negotiations, or if the Dispute Resolution Committee is unable to resolve a dispute on a matter submitted to it within the time frame established by the Authorized Representatives, the Parties agree to try in good faith to settle the dispute by mediation under the Commercial Mediation Rules of the American Arbitration Association, before resorting to some other dispute resolution procedure; provided that a Party may not invoke mediation unless it has provided the other with written notice of the dispute and has attempted in good faith to resolve such dispute through negotiation. Notwithstanding the foregoing, any Party may seek immediate equitable relief, without attempting to settle a dispute through mediation.

20. MEMBER'S WITHDRAWAL FROM AEPCO.

20.1 Member Withdrawal. If the Member elects to withdraw from membership in AEPCO, the terms of this Agreement shall remain in full force and effect except as provided in the Withdrawal Agreement executed by AEPCO and the Member.

20.2 References. For the purposes of this Agreement, each reference to the "Member" shall mean (i) the withdrawn Member from and after the effective date of the Member's withdrawal from AEPCO in accordance with the Withdrawal Agreement, or (ii) any permitted assignee (other than an assignee pursuant to an Assignment for Security) from and after the effective date of an assignment of this Agreement by the Member as provided in the Withdrawal Agreement. Each reference to a "Member" or to the "Members" of AEPCO shall include any Class A Member or Members (i) which withdraw or have withdrawn from AEPCO as provided above; (ii) whose membership in AEPCO has been suspended or terminated; or (iii) any permitted assignee (other than an assignee pursuant to an Assignment for Security) of such Class A Member or Members, except that any reference to an approval of the Class

A Members shall not include any withdrawn Member or Members or such permitted assignees.

21. NOTICES.

All communications, notices, requests, demands, authorizations, consents, waivers or other modifications provided, permitted or required by this Agreement shall be communicated in writing or by a telecommunications device capable of creating a written record, and any such notice shall become effective: (a) upon personal delivery thereof, including, without limitation, by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by such a telecommunications device, upon transmission thereof, provided such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to either Party hereto at its address set forth below or, in the case of either such Party hereto, at such other address as such Party may from time to time designate by written notice to the other Party hereto.

If to AEPCO:
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
P.O. Box 670
1000 South Highway 80
Benson, Arizona 85602
Attention: Executive Vice President and General Manager
Fax: (520) 586-5576 or 5402

If to Member:
MOHAVE ELECTRIC COOPERATIVE, INC.
P.O. Box 1045
Bullhead City, AZ 86430
Attention:
Fax: 520-763-6094

22. MISCELLANEOUS.

22.1 Indemnification, Mutual Indemnification, Risk of Loss and Insurance Obligations.

(a) Indemnification. The Member shall indemnify and hold AEPCO harmless from and against any and all losses, costs, liabilities, damages and expenses (including without limitation attorneys' fees and expenses through appeal) of any kind incurred or suffered by AEPCO, or any third party, pursuant to, as a result of, or in connection with any resale by the Member of capacity, energy or both except for losses, costs, liabilities, damages and expenses (including without limitation attorneys' fees and expenses through appeal) caused by AEPCO, including increased costs referred to in Section 14.2 hereof, or any third party, as a result of an act or omission that (a) is not Prudent Utility Practice or (b) is a breach of this Agreement.

(b) Mutual Indemnity. Except as otherwise provided in Section 22.1(a) above, Member and AEPCO shall each indemnify and save each other Party and the directors, agents, officers, and employees of each such other Party, harmless from and against any liability, loss, damage, claims, costs, and expenses (including reasonable attorneys' fees and court costs through appeal) incurred or claimed on account of injury to persons (including death) or damage or destruction of property, occasioned by the act or omission of the indemnifying party or its directors, officers, employees, agents or contractors in the performance of this Agreement, except to the extent that such liability, loss, damage, claim, costs, or expense results from the gross negligence or willful misconduct of the indemnified party; provided however, that:

(1) Each Party shall be solely responsible to its own employees and employees of third parties who are contracted to perform work for it, for all claims or benefits due for injuries occurring in the course of their employment or arising out of any workers' compensation law (except for claims for which the action or nonactions of the other Party was a proximate cause of such claims for benefits which are recoverable by the Party's employees from the other Party), and each Party shall indemnify and save the other Party harmless from and against any liability, loss, damage, claims, costs, and expenses (including reasonable attorneys' fees and court costs through appeal) relating to its own employees or employees of third parties who are contracted to perform work for it for such claim or benefit, except for such exception.

(2) To the fullest extent permitted by Law, neither Party shall be liable to the other for any indirect, consequential, multiple or punitive damages.

(c) Risk of Loss. Except as otherwise provided in this Section 22.1 and except for loss, injury, damages, or destruction that result from a breach or default of a Party's duty or obligation as set forth herein, Member and AEPCO shall each bear their own respective risk of loss for any loss, injury, damage, or destruction to their respective property, facilities, equipment and for the replacement or repair of such property.

(d) Insurance Obligations. The Parties agree to obtain and maintain, at a minimum, levels of insurance coverage in accordance with Prudent Utility Practice. The provisions of this Section 22.1 shall not be construed so as to relieve any insurer of its obligation to pay any insurance proceeds in accordance with the terms and conditions of any insurance policy of any Party.

22.2 Force Majeure. No Party shall be considered to be in default in the performance of any of its obligations under this Agreement when a failure of performance shall be

due to a Force Majeure. The Party claiming excused failure of performance shall promptly contact the other Party and, upon the written request of such other Party, shall promptly provide evidence that a Force Majeure has caused failure of performance. Any Party rendered unable to fulfill any obligation by reason of a Force Majeure shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved.

22.3 Other Corporate Documents. Whenever this Agreement authorizes AEPCO to otherwise amend a schedule hereto, to develop and implement policies or to make other decisions or do other acts in its sole discretion, AEPCO shall do so substantially in accordance with the applicable provisions of its duly adopted articles of incorporation, bylaws and corporate policies, and AEPCO shall not do so contrary to this Agreement. Any failure on the part of AEPCO to comply with this Section 22.3 shall not relieve the Member of any obligation under this Agreement which existed prior to such failure to act or act of AEPCO, but the Member shall not otherwise be prevented or limited in asserting any other rights it may have against AEPCO in respect of such failure.

22.4 Information Requirements. AEPCO and the Member shall each furnish to the other promptly upon request any and all information about itself, its financial condition, business and properties which may be necessary or desirable to facilitate any financing undertaken by the requesting Party or for any continuing disclosure obligation incurred by the requesting Party in connection with any such financing. The supplying Party shall be responsible only to the requesting Party for the accuracy and completeness of the information furnished and shall have no responsibility or liability for the manner in which such information is used or its appropriateness for such use. The supplying Party shall have no liability to any third party to which the requesting Party may furnish this information or any excerpt therefrom or summary thereof and shall be entitled to receive appropriate assurances and indemnities from the requesting Party to that effect as a condition to providing such information, provided that no such assurance or indemnity shall relieve the supplying Party of liability to the requesting Party for the accuracy and completeness of the information supplied.

22.5 Confidentiality.

(a) The Parties acknowledge that during the course of this Agreement, the Parties will have access to Confidential Information of AEPCO, the Member, and others. The Parties agree that the Parties or any persons employed by the Parties shall not, during the term of this Agreement or at any time thereafter, use or disclose any such Confidential Information to third parties and that the Parties shall take appropriate measures to protect the Confidential Information and prevent its disclosure. The Parties further agree that while AEPCO shall have access to Member's load and sales forecasts, AEPCO shall not, during the term of this Agreement or at any time thereafter, share or disclose such Member's Confidential Information in the specific with other

due to a Force Majeure. The Party claiming excused failure of performance shall promptly contact the other Party and, upon the written request of such other Party, shall promptly provide evidence that a Force Majeure has caused failure of performance. Any Party rendered unable to fulfill any obligation by reason of a Force Majeure shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved.

22.3 Other Corporate Documents. Whenever this Agreement authorizes AEPCO to otherwise amend a schedule hereto, to develop and implement policies or to make other decisions or do other acts in its sole discretion, AEPCO shall do so substantially in accordance with the applicable provisions of its duly adopted articles of incorporation, bylaws and corporate policies, and AEPCO shall not do so contrary to this Agreement. Any failure on the part of AEPCO to comply with this Section 22.3 shall not relieve the Member of any obligation under this Agreement which existed prior to such failure to act or act of AEPCO, but the Member shall not otherwise be prevented or limited in asserting any other rights it may have against AEPCO in respect of such failure.

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22.5 Confidentiality.

(a) The Parties acknowledge that during the course of this Agreement, the Parties will have access to Confidential Information of AEPCO, the Member, and others. The Parties agree that the Parties or any persons employed by the Parties shall not, during the term of this Agreement or at any time thereafter, use or disclose any such Confidential Information to third parties and that the Parties shall take appropriate measures to protect the Confidential Information and prevent its disclosure. The Parties further agree that while AEPCO shall have access to Member's load and sales forecasts, AEPCO shall not, during the term of this Agreement or at any time thereafter, share or disclose such Member's Confidential Information in the specific with other

Members of AEPCO, but may do so only in the aggregate form, i.e., to include such information in an aggregate total of load or sales forecasts for all of the Class A Members. The Parties further agree not to disclose to any other Person, or otherwise display for any purposes any books, records, worksheet, data, invoice, document, drawing, letter, report, tape or any other media, or any copy or reproduction thereof, belonging to, generated by, or pertaining to the other Party without written authorization from a duly authorized representative of the other Party. Before a Party communicates any Confidential Information to that Party's professional consultants, including, but not limited to, attorneys, accountants, investment bankers, brokers, bankers, technical and rate consultants, and engineers, such Party shall expressly advise such professional consultants in writing that the Confidential Information to be communicated must be kept confidential and shall not be made available to, or communicated to third parties. Such Party shall be responsible for any breach of this Section 22.5(a) by any such professional consultant. Before a Party communicates the Confidential Information to such professional consultants, the Party shall require that such professional consultants furnish a certificate to the Party acknowledging an agreement to comply with the provisions of this Section 22.5(a). Before such professional consultants make available or communicate such Confidential Information to anyone in the employ of such professional consultant, or to the firm to which such professional consultant belongs, such professional consultant shall obtain, and furnish to the Party, a certificate from such employee or firm acknowledging an agreement to comply with the provisions of this Section 22.5(a). This Section 22.5(a) shall not apply to Confidential Information requested of a Party by a Governmental Authority having jurisdiction.

(b) For purposes of this Agreement, "Confidential Information" means any and all information of either Party that is not generally known by others with whom the Party does or plans to compete or do business. Confidential Information includes without limitation such information, whether written or oral, related to: (i) a Party's development, research, testing, system, operations, and production activities; (ii) all products invented, researched, developed, planned, tested, manufactured, sold, licensed, leased, or otherwise distributed or put into use by the Party, together with all services provided or planned by the Party during the term of this Agreement; (iii) the Party's costs, sources of supply, strategic plans, resource plans, and capacity; (iv) the Party's pricing, cost-of-service, methods of allocation; (v) the identity and special needs of the customers, Members and other organizations with whom the Party has business relationships and the nature of those relationships; (vi) the Party's sales contracts and their terms and conditions; and (vii) the Party's marketing studies, surveys, plans and projections. Confidential Information also includes information that the Party receives or has received as confidential belonging to those who do business with it and, except to the

extent disclosed by the Party on a non-confidential basis, any intellectual property.

"Confidential Information" does not include information that is generally available to the public or becomes generally available to the public or information given pursuant to an order of a Governmental Authority of competent jurisdiction, provided that the Party shall promptly advise the other Party of any subpoenas or other process served on the Party requesting information that would otherwise be confidential to enable the other Party to take such action as it determines to be appropriate to protect its rights and interests.

(c) The Parties further agree to enter into written agreements regarding the non-disclosure and the non-use of Confidential Information when requested to do so by other organizations which provide proprietary data requested or obtained by the Party in connection with this Agreement.

22.6 Third Party Beneficiaries. AEPCO and the Member agree that RUS, while either the Member or AEPCO is a borrower of RUS, is a third-party beneficiary of this Agreement. AEPCO and the Member further agree that no other Member of AEPCO nor any other third party, except RUS, is a third-party beneficiary of this Agreement.

22.7 Obligations of RUS. The Parties agree that RUS shall not, merely due to an Assignment for Security, be deemed to assume or be bound to perform the duties of either Party to this Agreement, except to the extent the Administrator shall agree in writing to accept and be bound by such obligations.

22.8 Validity of Agreement. AEPCO and Member acknowledge and agree that the terms and conditions of the Agreement are valid, binding and enforceable as to AEPCO and Member according to its terms.

22.9 Headings. The descriptive headings of the various sections of this Agreement and the Exhibit and Schedules attached hereto have been inserted for convenience of reference only and shall not be construed as to define, expand, or restrict the rights and obligations of the Parties.

22.10 Waiver of Trial by Jury. Any suit, action or proceeding, whether claim, counterclaim or cross-claim, brought or instituted by either Party hereto on or with respect to this Agreement or any event, transaction or occurrence arising out of or in any way connected with this Agreement shall be tried only by a court and not by a jury. **EACH PARTY HEREBY EXPRESSLY WAIVES ANY RIGHT TO A TRIAL BY JURY IN ANY SUCH SUIT, ACTION OR PROCEEDING. THIS WAIVER OF RIGHT TO TRIAL BY JURY IS GIVEN KNOWINGLY AND VOLUNTARILY BY EACH PARTY, AND IS INTENDED TO ENCOMPASS INDIVIDUALLY EACH INSTANCE AND EACH ISSUE AS TO WHICH THE RIGHT TO A TRIAL BY JURY WOULD OTHERWISE ACCRUE. A**

**PARTY MAY FILE A COPY OF THIS PARAGRAPH IN ANY PROCEEDING AS CONCLUSIVE EVIDENCE OF A PARTY'S WAIVER OF TRIAL BY JURY.**

22.11 Attorneys Fees and Legal Expenses. If any arbitration proceeding or action shall be brought to recover any amount under this Agreement, or for, or on account of any breach of, or to enforce or interpret any of the terms, covenants, or conditions of this Agreement, the prevailing Party shall be entitled to recover from the other Party, as part of the prevailing Party's costs, reasonable attorneys' fees, the amount of which shall be fixed by the arbitrators or by the court, and shall be made a part of any award or judgment rendered.

22.12 Venue. The proper venue for any proceeding at law or in equity or under the provisions for arbitration shall be Maricopa County, Arizona, and the Parties waive any right to object to the venue.

22.13 RUS Approval No Waiver. The Parties hereby acknowledge and agree that the approval by the Administrator of this Agreement shall not in any way constitute or be deemed to be a waiver by RUS of any of its rights, or any of AEPCO's obligations under the AEPCO Loan Contract, any AEPCO Note, loan or security agreement between RUS and AEPCO or under applicable RUS regulations. The Parties further agree that, in the event of a conflict between this Agreement and such AEPCO Loan Contract, AEPCO Note, loan or security instrument or applicable RUS regulations in effect on the Effective Date, the terms of such AEPCO Loan Contract, AEPCO Note, loan or security instrument or the applicable regulation in effect on the Effective Date shall prevail.

22.14 Status as Member No Defense. The Member shall not assert as a defense, offset or condition to any of its obligations hereunder any rights, claims or defenses that the Member may have against AEPCO due to or arising out of the Member's status as a Class A Member of AEPCO (including any rights, claims or defenses contained in or arising out of the AEPCO Bylaws or Articles of Incorporation) or any other relationship between the Member and AEPCO other than the relationship established under this Agreement.

IN WITNESS WHEREOF, AEPCO and the Member have caused this Agreement to be executed, attested, and delivered by their respective duly authorized officers as of the ____ day of _____, ____.

ARIZONA ELECTRIC POWER
COOPERATIVE, INC.

By: _____
Name: _____
Title: _____

ATTEST:

_____
Name: _____
Title: _____

MOHAVE ELECTRIC
COOPERATIVE, INC.

_____
_____
By: _____
Name: _____
Title: _____

ATTEST:

_____
Name: _____
Title: _____

# APPENDIX A
# TO THE PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

## DEFINITIONS

# Rate Schedule A

To Partial Requirements
Capacity and Energy Agreement

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## Rate Schedule A

1. **Introduction**

This Rate Schedule A specifies the rates and Fixed Charge and the methodology for developing and administering those rates and the Fixed Charge for capacity and energy sales made by AEPCO to its Partial Requirements Member pursuant to the Partial Requirements Capacity and Energy Agreement (the "Agreement") to which this Rate Schedule A is attached.

Exhibit A-1 to this Rate Schedule A sets forth the rates and Fixed Charge which are currently in effect in accordance with the Agreement. Exhibit A-2 specifies the methodology for calculating the rates and Fixed Charge, utilizing the treatment of expenses and certain revenues or credits depicted in Exhibit A-3 and the calculation of ACP and AC in Exhibit A-5. Exhibit A-4 sets forth a sample of the bill to be presented to Member by AEPCO for services provided pursuant to the Agreement.

This Rate Schedule A applies to AEPCO's Resources in existence as of Closing Date and those in which the Partial Requirements Member obtains an ACP in accordance with the Agreement.

2. **Conditions of Service**

2.1 **Applicability**

The rates, Fixed Charge and methodology for setting such rates, charges and adjustments is set forth in this Rate Schedule A and shall only apply to the Member that has executed a Partial Requirements Capacity and Energy Agreement with AEPCO. Member shall make payment for electric service under this Agreement through the rates and Fixed Charge established by AEPCO in accordance with this Agreement and Rate Schedule A. As a Partial Requirements Member, Member shall remain obligated at all times during the term of this Agreement, including periods in which a Force Majeure has been declared, to pay its Fixed Charge and O&M charge as determined in accordance with this Rate Schedule A.

2.2 **Power Factor and Demand Overrun Adjustments**

If the Power Factor of Member measured at such Member's Delivery Point(s) at the time of Member peak demand is outside a bandwidth of 90% leading to 90% lagging (the bandwidth shall be 95% leading to 95% lagging as of January 1, 2005, provided that a similar change in bandwidth is made effective for all Class A Members), a Power Factor Adjustment shall be separately charged to such Member. The Power Factor Adjustment shall be the product of a power factor adjustment (as set forth below) multiplied by the O&M rate. 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; and |
| mkW | = | Member Metered kW, and |
| mpf | = | measured power factor at the time of Member peak demand, and |
| bpf | = | 0.90 prior to January 1, 2005, and 0.95 thereafter. |

In addition, if the Member Billing Demand for the Partial Requirements Member exceeds its Allocated Capacity, then Partial Requirements Member shall also be separately charged a Demand Overrun Adjustment. Such Demand Overrun Adjustment shall equal the product of the 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 Billing Demand in kW, and
AC = Allocated Capacity of Member, in kW.

The Power Factor Adjustment and the Demand Overrun Adjustment, as set forth at the levels of take established in Schedule B, to the extent applicable, shall be added to the monthly bill for payment by the Member in addition to the rates and Fixed Charge for capacity and energy sales.

2.3 **Stranded Cost Recovery**

AEPCO's Stranded Costs, as may be authorized to be recovered under applicable Law, shall include and currently consist of a Competitive Transition Charge (CTC) and a Regulatory Asset Charge (RAC). The rates and Fixed Charge specified in Exhibit A-1 shall be adjusted to include a stranded cost recovery charge reflecting the recovery of AEPCO's Stranded Costs. Bills rendered under the terms of this Rate Schedule A shall include charges for any Stranded Costs that AEPCO may be authorized to recover under applicable Law and Member is authorized under applicable Law and able to collect. Such Stranded Cost charges shall be separately itemized as specified in Exhibit A-4 hereof. AEPCO's CTC and RAC shall be added to the Member's monthly bill for collection and payment by the Member in addition to the rates and Fixed Charge for capacity and energy sales. The Member shall collect all such funds which it is authorized under applicable Law and able to collect and remit to AEPCO those funds as specified in Section 3.6 hereof. The CTC shall apply only to energy competitively supplied by non-parties to individual customers within the Member's Distribution Service Area, while the RAC shall apply to all energy sold in the Member's Distribution Service Area, or as otherwise ordered by applicable Law. AEPCO's right to recover the RAC may be assigned to TRANSCO pursuant to the Restructuring Agreement.

2.4 **Taxes and/or Assessments**

The rates and Fixed Charge set forth in Exhibit A-1 to Rate Schedule A herein do not include sales taxes, transaction privilege taxes or regulatory assessments or similar governmental impositions which are, or may in the future be, levied on AEPCO by any Governmental Authority having jurisdiction and which are not included in the AEPCO Revenue Requirement used to develop the rates and Fixed Charge. Therefore, bills rendered under the terms of this Rate Schedule A shall include all such federal, state and local sales taxes, transaction privilege taxes, assessments or similar governmental impositions. Such taxes and/or assessments shall be itemized and added to the bill in addition to the rates and Fixed Charge for capacity and energy sales for payment by the Member.

2.5 **Charges**

The monthly charge billed to the Partial Requirements Member in accordance with Section 5.1 of the Agreement and as provided for in applicable provisions of Section 5 of the Agreement, shall consist of the following:

1. the Fixed Charge as set forth in Exhibit A-1 hereof; plus,
2. the O&M charge, which shall be the product of the O&M rate set forth in Exhibit A-1 hereof multiplied by the Member Billing Demand; plus,
3. the energy charge, which shall be the product of the energy rate set forth in Exhibit A-1 hereof multiplied by the Member Billing Energy; plus
4. any Power Factor and Demand Overrun Adjustments pursuant to Section 2.2 hereof; plus,
5. any Stranded Cost recovery pursuant to Section 2.3 hereof, plus
6. all taxes and/or assessments pursuant to Section 2.4 hereof, if any; plus
7. any charges incurred pursuant to Schedule B to this Agreement.

2.6 **Sample Bill**

A form of bill which sets forth for illustrative purposes rates, charges and adjustments to be made by AEPCO to Member pursuant to this Agreement, including this Rate Schedule A is attached as Exhibit A-4 to this Rate Schedule A. Actual billings made by AEPCO to Member pursuant to Section 5.1 of this Agreement shall be substantially in the form of, and contain the information set forth in, such sample bill.

3. **Rate Development**

3.1 **Rate Administration**

The Board of Directors of AEPCO shall review the level of revenues generated by the rates and Fixed Charge set forth in Exhibit A-1 to this Rate Schedule A and revenues generated from other rates and charges to the Class A Members, together with revenues generated from all other sources, to determine their sufficiency to meet AEPCO's Revenue Requirement. In the event that the rates and Fixed Charge as set forth in Exhibit A-1 do not provide revenues sufficient, but only sufficient, to satisfy AEPCO's Revenue Requirements From Partial Requirements Member, the Board of Directors of AEPCO shall establish new rates and a new Fixed Charge, for electric service to the Partial Requirements Member pursuant to the procedures set forth in Section 5.5 of the Agreement and otherwise comply with those provisions pertaining to rates and the Fixed Charge as set forth in Section 5 of the Agreement. Such new rates and Fixed Charge established in conjunction with new rates for the All Requirements Members shall be submitted to the RUS and shall not become effective until approval of RUS is obtained, at which time Exhibit A-1 (and other Exhibits, as may be applicable) to this Rate Schedule A shall be modified to reflect the new rates and Fixed Charge in effect.

3.2 **Development of Cost of Service and Revenue Requirement**

AEPCO rates and the Fixed Charge developed under this Rate Schedule A charged to its Partial Requirements Member and rates and charges to the

other Class A Members shall be based upon AEPCO's Revenue Requirement and cost of service studies utilizing a twelve-month test period ending not more than six months before such cost of service studies are first considered by AEPCO. Accounting data for such test period shall be taken from the books and records of AEPCO.

The test period data for the cost of service studies shall be adjusted to reflect known and measurable changes to expenses and billing determinants that have occurred during the test period and/or are expected to continue to occur after the test period (i.e. normalized for the test period). The cost of service studies may also be normalized for changes that are known and measurable which will occur after the test period (out of period changes).

The fixed, O&M and energy components of AEPCO's Revenue Requirement From Partial Requirements Member shall be developed from fixed, O&M and energy components of AEPCO's Revenue Requirement From AEPCO's Class A Members pursuant to Exhibit A-2 to this Rate Schedule A.

3.3 **Classification of Expenses**

The expenses and revenue credits, included in the cost of service studies shall be classified as fixed, O&M, and/or energy as set forth in Exhibit A-2 and depicted in Exhibit A-3 hereto.

3.4 **Development of Rates and the Fixed Charge**

Once the components of fixed, O&M, and energy for AEPCO's Revenue Requirement From Partial Requirements Member are determined pursuant to Section 3.2 and all expenses are classified pursuant to Section 3.3, the rates and the Fixed Charge to be charged pursuant to the Agreement shall be determined in accordance with Exhibit A-2. The billing determinants for the Fixed Charge shall be the ACP as specified in Section 3.5 below. The billing determinants for the O&M and energy rates shall be as set forth in Sections 5.3 and 5.4 of Exhibit A-2, respectively.

3.5 **Allocated Capacity Percentage (ACP) and Allocated Capacity (AC)**

Appendix A to Exhibit A-5 sets forth the Allocated Capacity Percentages (ACP) that shall be used to develop the Fixed Charge for the Partial Requirements Member. Appendix B to Exhibit A-5 to this Rate Schedule A identifies the AEPCO Existing Resources as well as the Allocated Capacity (AC) for the Partial Requirements Member.

3.6 **Stranded Cost Recovery Charges**

Revenue received by the Partial Requirements Member to recover AEPCO's Stranded Costs as authorized by the ACC shall be remitted and paid to AEPCO as provided for hereunder. Such revenues anticipated to be remitted to AEPCO shall be treated in AEPCO's annual cost of service studies as revenue generated from sources other than the Class A Members and shall be credited as set forth in Exhibit A-2. The Partial Requirements Member shall collect and remit to AEPCO all revenues resulting from the imposition of the RAC on all energy sold in the Member's Distribution Service Area, as authorized by the ACC. The Partial Requirements Member shall collect and remit to AEPCO a portion of the total revenues resulting from the imposition

of the CTC on energy competitively supplied by non-parties to individual customers within the Member's Distribution Service Area. Such portion of the revenues resulting from such imposition of the CTC which shall be remitted to AEPCO shall equal the amount obtained by multiplying the total revenue so collected by the Partial Requirements Member pursuant to such imposition of the CTC by a ratio obtained by dividing the then current O&M component by the sum of the fixed charge component and the O&M component (all as determined pursuant to Exhibit A-2 hereof), or as otherwise required by the ACC.

# EXHIBIT A-1

# TO RATE SCHEDULE A

## Partial Requirements Member

## Rates and Fixed Charge

**EXHIBIT A-1**
**TO RATE SCHEDULE A**

**Partial Requirements Member**
**Rates and Fixed Charge**
**(Effective as of _____)**

| | |
|---|---|
| **Fixed Charge** | |
| Mohave Electric Cooperative, Inc. | [ $769,724 per month,] |
| **O&M Rate** | [ $ 4.96 per kW/month] |
| **Energy Rate** | $0.01608 per kWh used during the billing period. |

**NOTE: THE RATES AND FIXED CHARGE SHALL BE ADJUSTED FURTHER FOR ANY POWER FACTOR ADJUSTMENT, DEMAND OVERRUN ADJUSTMENTS, STRANDED COST RECOVERY, AND TAXES AND/OR ASSESSMENTS, PURSUANT TO SECTIONS 2.2, 2.3, AND 2.4, RESPECTIVELY, AND ANY ADJUSTMENTS RESULTING FROM SCHEDULE B OF THE AGREEMENT.**

# EXHIBIT A-2

# TO RATE SCHEDULE A

## Development of Rates and Fixed Charge

**Exhibit A-2 to Rate Schedule A**
**Development of Rates and Fixed Charge**

1.0 **Introduction**

This Exhibit A-2 specifies the methodology for the development of rates and the Fixed Charge. This methodology shall be applied to AEPCO expenses and revenues described herein which are maintained under the Uniform System of Accounts and classified as (a) fixed, (b) O&M, or (c) energy . All amounts described hereunder and included in such accounts shall be those amounts recorded in AEPCO's financial records for the test period used in the applicable cost of service study from which the rates and Fixed Charge are to be developed. Such amounts when adjusted for appropriate credits and normalized with appropriate adjustments are the AEPCO costs and expenses which shall be used as the basis for the cost of service which determines AEPCO's Revenue Requirement which is the sum of: (i) revenues to be recovered from the Partial Requirements Member through charging the rates applied to its Member Billing Demand and Member Billing Energy and Fixed Charge pursuant to its Partial Requirements Capacity and Energy Agreement, plus (ii) revenues to be recovered from the All Requirements Members through charging rates pursuant to their Existing Wholesale Power Contracts, plus (iii) AEPCO revenues from all other sources.

2.0 **Classification of Expenses and Revenues**

2.1 Classifications

For purposes of this Exhibit A-2 to Rate Schedule A, classifications shall be made of the AEPCO expenses and revenues from sources other than sales to AEPCO Class A Members and maintained and identified using the Uniform System of Accounts, for the purpose of identifying such expenses as either: (a) fixed (F), (b) Operations and Maintenance ("O&M") (O), or(c) energy (E), as follows;

*(The account numbers refer to accounts maintained by AEPCO under the Uniform System of Accounts in its financial records.)*

Amounts in Accounts 500 through 554, with the exception of Accounts 501 and 547, shall each be classified as Production-O (consisting of operations and maintenance expenses related to steam and other power generation).

Amounts in Accounts 501 and 547 shall be separated and classified either as: Fuel-F (consisting of O&M and amortization expenses relating to the Carbon Coal Company investment and gas transportation reservation charges), or as Fuel-E (consisting of remaining Accounts 501 and 547 Expenses).

Amounts in Accounts 555 shall be separated and classified as: Purchased Power - F (capacity or demand charges), Purchased Power-O (O&M related charges), or as Purchased Power - E (energy charges).

Amounts in Accounts 556 and 557 shall be classified as: Other Power Supply-O (System Control, dispatching and O&M charges).

Amounts in Account 565 shall be separated and classified as: Wheeling Expense-O (consisting of firm wheeling charges), or as and Wheeling Expense-E (consisting of non-firm wheeling charges).

Amounts in Accounts 901-916, which consist of consumer accounts, customer accounts and sales expense, shall be classified as Customer-O.

Based on the respective ratios of labor expenses in (a) Steam Power Generation (Accounts 500-507 and 510-514) and Other Power Production (Accounts 546-554) and (b) Other Power Supply (Accounts 556 and 557), compared to the sum of all such labor expenses, the amounts in Accounts 920-923 and 927-932 shall each be separated and classified as either: (a) Administrative & General I-O, or as (b) Administrative & General I-E.

Based on the portions of Production Plant (Accounts 300-316) and General Plant (Accounts 389-399) respectively associated with (a) fixed, (b) O&M, and (c) energy, compared to the sum of such expenses, the amounts in Account 924 shall be respectively separated and classified as either: (a) Administrative & General II-F, (b) Administrative & General II-O, or as (c) Administrative & General II-E.

Based on the respective ratios of labor expenses in (a) Steam Power Generation (Accounts 500-507 and 510-514) and Other Power Production (Accounts 546-554), (b) Other Power Supply (Accounts 556 and 557), (c) Sales Expense (Accounts 911-916) and (d) Administrative and General (Accounts 920-923 and 927-932), compared to the sum of such labor expenses, the amounts in Accounts 925 and 926 shall each be separated and classified as either: (a) Administrative & General III-O, or as (b) Administrative & General III-E.

The revenue amounts in Accounts 447-456 shall be first aggregated into credits and then separated based upon the following [calculus] and classified as either: (a) Credits-F, (b) Credits-O, or as (c) Credits-E. The portion of such credits corresponding to the product resulting from the multiplying: (a) AEPCO average system energy cost of producing electricity, by: (b) AEPCO's kWh sales to other than AEPCO's Class A Members shall be classified as Credits-E. The remainder of such credits shall be classified as Credits-F and Credits-O based upon a pro rata dollar division of such credits based upon the amount of expenses assigned to the fixed and O&M categories compared to the sum of such expenses.

Margins shall be classified and assigned to the fixed category.

2.2 **Depiction**

The expense and revenue accounts, their classification into fixed, O&M and energy, and the adjustments specified in this Exhibit A-2 are depicted in tabular form in Exhibit A-3.

3.0 Fixed Capacity and O&M Component.

3.1 Purpose and Elements

The purpose of this Section 3.1 and Sections 3.2 and 3.3 hereof is to set forth the methodology for the development of the rates and Fixed Charge attributable to electric service under the Partial Requirements Capacity and Energy Agreement. The fixed capacity component and the O&M component shall be used to calculate and determine the Fixed Charge as provided in Section 5.2 hereof, and the O&M rate as provided in Section 5.3 hereof.

3.2 **Fixed Capacity Component**

The fixed capacity component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as fixed, as applicable pursuant to Section 2 hereof:

Account 403 (Depreciation & Amortization Expense),
Account 408 (Ad Valorem Taxes),
Accounts 427-428 (Interest on Long Term Debt, Interest Charged to Construct, Other Interest Expense, and Other Deductions),
Account 501 (Fuel-F only),
Account 547 (Fuel-F only)
Account 555 (Purchased Power - F only)
Account 924 (Administrative & General II-F only), and
Margin in an amount sufficient to assure AEPCO of, at a minimum, a reasonable level of working capital and maintenance of annual coverage ratios, or any other financial covenants or tests prescribed or imposed by RUS or any other applicable Financial Entities,
Less Accounts 447-456 (Credits-F only, including recovery of

AEPCO's Competitive Transition Charge from the All Requirements Members to be allocated to fixed costs in Account 451, or its successor account in the ratio obtained by dividing the fixed component of the revenue requirement by the sum of such fixed component plus the O&M component of the revenue requirement).

3.3 **O&M Component**

The O&M component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as O&M, as applicable pursuant to Section 2 hereof:

Accounts 500-554, except for Accounts 501 and 547 (Production-O only),
Account 555 (Purchased Power-O only)
Accounts 556 and 557 ( Other Power Supply-O only),
Account 565 (Wheeling Expense-O only),
Accounts 901-916 (Customer-O only),
Accounts 920-923 (Administrative & General I-O only), 924

(Administrative & General II-O only), 925-926 (Administrative & General III-O only), and 927-932 (Administrative & General I-O only),

Less Accounts 447-456 (Credits-O only, including recovery of AEPCO's Competitive Transition Charge from both Partial Requirements Members and the All Requirements Members to be allocated to O&M costs in Account 451, or its successor account in the ratio set forth in Section 3.6 of this Rate Schedule A.)

4.0 **Energy Component**.

The energy component shall be the sum of either the amounts in the following accounts, or the portion of such amounts classified as energy, as applicable, pursuant to Section 2 hereof:

Accounts 501 and 547 (Fuel-E only),
Accounts 555 (Purchased Power-E only),
Account 565 (Wheeling Power-E only), and
Accounts 920-923 (Administrative & General I-E only), 924 (Administrative & General II-E only), 925-926 (Administrative & General III-E only), and 927-932 (Administrative & General I-E only),

Less Accounts 447-456 (Credits-E only, including recovery of AEPCO's Competitive Transition Charge to be recorded in Account 451, or its successor account).

(PT. What portion of recovery of CTC's will be allocated to Fixed Charge, O&M and energy?)

5.0 **Partial Requirements Member Rates and Fixed Charge.**

5.1 **Elements**

The rates and Fixed Charge for electric service under the Agreement to the Partial Requirements Member shall consist of (a) the Fixed Charge, composed of an appropriate allocated fixed capacity component, including a margin, (b) an O&M rate, and (c) an energy rate.

5.2 **Fixed Charge**

The monthly Fixed Charge for the Partial Requirements Member, stated in dollars, shall equal: (a) the expenses less revenue credits used to determine the current fixed capacity component in Section 3.2 of this Exhibit A-2, and shall include prior period losses (negative equity) resulting from deficiencies or shortfalls incurred up to the Closing Date from failures of Members to meet their portion of AEPCO's Revenue Requirement, (b) multiplied by the ACP for the Partial Requirements Member, and (c) divided by twelve (12) to convert to a monthly charge.

5.3 **O&M Rate**

The O&M rate for the Partial Requirement Member shall equal the O&M component comprised of the expenses, less revenue credits as calculated in Section 3.3 of this Exhibit A-2, divided by the aggregate test year demand

billing units (stated in kW) developed in the cost of service study for the Class A Members. With respect to Partial Requirements Member, such demand billing units shall consist of the annualized Member Billing Demand of the test period, adjusted for known and measurable changes.

5.4 **Energy Rate**

The energy rate for the Partial Requirements Member shall equal the energy component comprised of the expenses, less revenue credits as calculated in Section 4.0 of this Exhibit A-2, divided by the aggregate test year energy billing units (stated in kWh) developed in the cost of service study for the Class A Members. With respect to Partial Requirements Member, such energy billing units shall consist of the annualized Member Billing Energy of the test period, adjusted for known and measurable changes.

6.0 **Revenue Shortfalls**

Any deficiencies or shortfalls in collections of AEPCO's Revenue Requirement From Partial Requirements Member will be recovered through appropriate adjustments to: (a) the O&M rate, or (b) the margin included in the Fixed Charge for the Partial Requirements Member. An adjustment will be made to the O&M rate to the extent such deficiencies or shortfalls are attributable to the collection of revenues for operations and maintenance expenses. An adjustment will be made to the margin included in the Fixed Charge for all other such deficiencies or shortfalls. Such deficiencies or shortfalls may also be recovered through a combination of appropriate adjustments to the O&M rate or the margins.

7.0 **No Adjustment for Transmission Losses.**

The billing determinants included in the cost of service study and used to develop and implement the rates and Fixed Charge shall be those metered at the Delivery Points after transmission losses. Consequently, AEPCO's Revenue Requirement developed as a result of such cost of service study, reflects the costs of generating or acquiring sufficient capacity and energy to cover transmission losses. Therefore, the rates developed as set forth herein implicitly encompass recovery of the costs associated with transmission losses and there is no need for a separate adjustment for transmission losses.

# EXHIBIT A-3

# TO RATE SCHEDULE A

## Classification of Expenses

Exhibit A-3 to Rate Schedule A
Classification of Expenses

| Uniform System Account No. | Description | Fixed Expenses (F) | O&M Expenses (O) | Energy Expenses (E) |
|---|---|---|---|---|
| | **Production and Other Power Supply** | | | |
| | **Steam Power Generation:** | | | |
| | **Operation:** | | | |
| 500 | Operation Supervision & Engineering | | X | |
| 501 | Fuel | X[1] | | X[1] |
| 502 | Steam Expenses | | X | |
| 505 | Electric Expenses | | X | |
| 506 | Miscellaneous Steam Power Expenses | | X | |
| 507 | Rents | | X | |
| | | | | |
| | **Maintenance:** | | | |
| 510 | Supervision & Engineering | | X | |
| 511 | Structures | | X | |
| 512 | Boiler Plant | | X | |
| 513 | Electric Plant | | X | |
| 514 | Miscellaneous Steam Plant | | X | |
| | | | | |
| | **Other Power Generation:** | | | |
| | **Operation:** | | | |
| 546 | Operation Supervision & Engineering | | X | |
| 547 | Fuel | X[1] | | X[1] |
| 548 | Generation Expenses | | X | |
| 549 | Miscellaneous Other Power Generation | | X | |
| 550 | Rents | | X | |

[1]All fuel related costs are assigned to the energy classification, except for Carbon Coal Company O&M expense and amortization of investment and gas transportation reservation charges which are assigned to the fixed classification because they do not pertain to fuel commodity costs.

| Uniform System Account No. | Description | Fixed Expenses (F) | O&M Expenses (O) | Energy Expenses (E) |
|---|---|---|---|---|
| | | | | |
| | **Maintenance:** | | | |
| 551 | Supervision & Engineering | | X | |
| 552 | Structures | | X | |
| 553 | Generating and Electric Equipment | | X | |
| 554 | Miscellaneous Other Power Generation | | X | |
| | | | | |
| | **Other Power Supply Expenses:** | | | |
| 555 | Purchased Power | X[2] | X[2] | X[2] |
| 556 | System Control & Load Dispatching | | X | |
| 557 | Other Expenses | | X | |
| | | | | |
| 565 | **Wheeling Expense** | | X[3] | X[3] |
| | | | | |
| 901-905 | **Consumer Accounts** | | X | |
| | | | | |
| 906-910 | **Customer Service & Information** | | X | |
| | | | | |
| 911-916 | **Sales Expense** | | X | |
| | | | | |
| | **Administrative & General:** | | | |
| 920 | Salaries | | X[4] | X[4] |

[2]Purchased power, capacity or demand charges are assigned to the fixed classification, any O&M charges to the O&M classification and energy charges and interchange expenses are assigned to the energy classification.

[3]Firm wheeling charges are assigned to the O&M classification and non-firm wheeling charges are assigned to the energy classification.

[4]Administrative and general expenses are assigned to the O&M and energy classifications based upon the distribution of production and other power supply labor expenses to the O&M and energy classifications.

| Uniform System Account No. | Description | Fixed Expenses (F) | O&M Expenses (O) | Energy Expenses (E) |
|---|---|---|---|---|
| 921 | Office Supplies & Expenses | | X[4] | X[4] |
| 922 | A&G Expenses Transferred Credit | | X[4] | X[4] |
| 923 | Outside Services | | X[4] | X[4] |
| 924 | Property Insurance | X[5] | X[5] | X[5] |
| 925 | Injuries & Damages | | X[6] | X[6] |
| 926 | Employee Pensions & Benefits | | X[6] | X[6] |
| 927 | Franchise Requirements | | X[4] | X[4] |
| 928 | Regulatory Commission Expenses | | X[4] | X[4] |
| 929 | Duplicate Charges Credit | | X[4] | X[4] |
| 930 | Miscellaneous General Expense | | X[4] | X[4] |
| 931 | Rents | | X[4] | X[4] |
| 932 | Maintenance of General Plant | | X[4] | X[4] |
| | | | | |
| 403 | **Depreciation & Amortization Expense** | X | | |
| | | | | |
| 408 | **Ad Valorem Taxes** | X | | |
| | | | | |
| | **Interest & Other Deductions:** | | | |
| 427 | Interest on Long Term Debt | X | | |
| 427 | Interest Charged to Construction | X | | |
| 427 | Other Interest Expense | X | | |
| 428 | Other Deductions | X | | |
| | | | | |

[5]Assigned to the fixed, O&M and energy classifications based upon the distribution of production and general plant between classifications.

[6]Assigned to the O&M and energy classifications based upon the distribution of total labor expenses to the O&M and energy classifications.

| Uniform System Account No. | Description | Fixed Expenses (F) | O&M Expenses (O) | Energy Expenses (E) |
|---|---|---|---|---|
| 447-456 | **Operating Revenues from Other Sources - Credit** | X[7] | X[7] | X[7] |
| | | | | |
| | **Margin Component** | X | | |
| | | | | |

[7]Revenue from sources other than AEPCO's Class A Members is assigned to the energy classification on the basis of AEPCO average cost of energy multiplied by kWh sales from such other sources. The remainder of such revenue including recovery of AEPCO's Stranded Costs is assigned to the fixed and O&M classifications on a pro-rata basis as set forth in Section 3.6 of this Rate Schedule A and Exhibit A-2, Sections 3.2 and 3.3 hereof, as applicable.

# EXHIBIT A-4

# SAMPLE BILL

# EXHIBIT A-4 TO RATE SCHEDULE A
# SAMPLE BILL

**INVOICE**

TO: **Mohave Electric Cooperative, Inc.**
**Post Office Box 1045**
**Bullhead City, Arizona 86430**

**ATTN: Robert E. Broz, General Manager**

**DATE: August 3, 2000**

**July, 2000**

| | |
|---|---|
| Schedule A Demand Charges | $1,481,601.18 |
| Schedule A Energy Charges | $969,476.48 |
| Stranded Cost Recovery | |
| Competitive Transition Charge (CTC) | $0.00 |
| Schedule B Charges | $83,354.86 |
| Integrated Resource Pool | $0.00 |
| ACC Gross Operating Revenue Assessment | $3,294.76 |
| SUBTOTAL DUE AEPCO | $2,537,727.28 |
| Less: Power Prepayment Program (see p A-4-4) | $0.00 |
| PLEASE PAY THIS AMOUNT | $2,537,727.28 |

Bills are due and payable at the AEPCO office August 18, 2000.

Payments received by AEPCO after August 18, 2000 shall accrue interest at the Contract Rate Of Interest

**MRT NOTE: The worksheet attachments for Resource Integration Agreement Merchant Sales and Merchant Purchases are not yet completed.**
**Regulatory Asset Surcharge, transmission and ancillary services will be billed by TRANSCO.**

**SAMPLE BILL**

**MOHAVE ELECTRIC COOPERATIVE, INC.**
**P.O. BOX 1045**
**BULLHEAD CITY, ARIZONA 86430**

**BILLING PERIOD: July, 2000**

**DATE: August 3, 2000** **DATE DUE: August 18, 2000**

| DESCRIPTION | | | | | CREDITS | CHARGES |
|---|---|---|---|---|---|---|
| **SCHEDULE A DEMAND CHARGES** | | | | | | |
| ALLOCATED CAPACITY (see A-4-5) FIXED CHARGE: | 122,800 | kW @ | $846,172.82 | | | $846,172.82 |
| MEMBER BILLING DEMAND (see A-4-5) @ O&M RATE: | 126,817 | kW @ | $4.789 | /kW | | 607,326.61 |
| POWER FACTOR CONTRIBUTION (see A-4-3): | 88 | kW @ | $4.789 | /kW | | 421.98 |
| AC DEMAND OVERRUN (see A-4-5): | 3.271% | X | $846,172.82 | | | 27,679.77 |
| CHEMSTAR LOAD CONTROL ADJUSTMENT: | 0 | kW @ | $0.000 | | 0.00 | |
| DEMAND SUBTOTAL | | | | | | $1,481,601.18 |
| **SCHEDULE A ENERGY CHARGES** | | | | | | |
| MEMBER BILLING ENERGY (Metered p A-4-3 less Schd B Overruns): | 64,502,760 | kWh @ | $0.015030 | /kWh | | 969,476.48 |
| FUEL ADJUSTMENT: | 64,502,760 | kWh @ | $0.000000 | /kWh | | 0.00 |
| ENERGY SUBTOTAL | | | | | | $969,476.48 |
| **SCHEDULE B CHARGES** | | | | | | |
| Highest DEMAND OVERRUN (see pp A-4-6): | 4,896 | kW @ | $14.663 | /kW | | 71,790.05 |
| MINIMUM DEMAND for O&M (see p A-4-5): | 0 | kW @ | $4.789 | /kW | | 0.00 |
| ENERGY Overruns (see pp A-4-8-1 et al): *** | 419,356 | kWh @ | $0.026354 | /kWh | | 11,051.67 |
| ENERGY Minimums (see pp A-4-9-1 et al): *** | 34,141 | kWh @ | $0.015030 | /kWh | | 513.14 |
| SCHEDULE B SUBTOTAL | | | | | | $83,354.86 |
| **STRANDED COST RECOVERY:** | | | | | | |
| COMPETITIVE TRANSITION CHARGE (CTC) MEC Wheeling, Member JMP, CSP JMP Loads | 0 | kWh @ | $0.009100 | /kWh | | 0.00 |
| FIXED CHARGE PORTION RETAINED: | $0.00 | @ | 67.87% | | 0.00 | |
| *STRANDED COST SUBTOTAL* | | | | | | $0.00 |
| ACC GROSS OPERATING REVENUE ASSESSMENT | $2,534,432.52 | X | 0.130% | | | $3,294.76 |
| **TOTAL PARTIAL REQUIREMENTS COST** | | | | | | **$2,537,727.28** |
| **INTEGRATED RESOURCE POOL:** | | | | | | |
| PURCHASES (see attached) | 0 | kWh @ | $0.000000 | /kWh | | 0.00 |
| SALES (see attached) | 0 | kWh @ | $0.000000 | /kWh | 0.00 | |
| | | SUBTOTAL | | | | $0.00 |
| ACC GROSS OPERATING REVENUE ASSESSMENT | $0.00 | X | 0.130% | | | 0.00 |
| | | **SUBTOTAL** | | | **$0.00** | **$2,537,727.28** |
| **TOTAL AMOUNT DUE** | | | | | | **$2,537,727.28** |

COST OF POWER $0.039343 /kWH

***** MRT NOTE: These records of hourly amounts will be summarized on one page of daily totals for the month.**

# SAMPLE BILL

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.**

**IN ACCOUNT WITH:** **MOHAVE ELECTRIC COOPERATIVE, INC.**
**P.O. BOX 1045**
**BULLHEAD CITY, ARIZONA 86430**

**DATE: August 3, 2000**

**BILLING PERIOD: July, 2000**

MEC Metered Load (In MDSA) & Sales (Out MDSA)

| DELIVERY POINT METERING | PRESENT READING | PREVIOUS READING | DIFF. | MULT. | KWH | KW | LOSS ADJUST FACTOR | KWH | KW |
|---|---|---|---|---|---|---|---|---|---|
| BIG BEND | 288011 | 205302 | 82709 | 100 | 8,270,900 | 17,400 | | | |
| MEDLIN | 698017 | 486387 | 211630 | 100 | 21,163,000 | 44,800 | | | |
| WILLOW VALLEY / SWAN | 174124 | 66519 | 107605 | 100 | 10,760,500 | 23,000 | | | |
| RIVIERA FROM DAVIS | 139 | 0 | 139 | 100 | (13,900) | 0 | | | |
| RIVIERA TO AIRPORT | 204 | 0 | 204 | 100 | 20,400 | 0 | | | |
| RIVIERA TOTAL | | | | | | | | 40,200,900 | 85,200 |
| BILL WILLIAMS | 488900 | 125192 | 363708 | 1 | 363,708 | 690 | 1.014 | 368,800 | 700 |
| BULLHEAD / DAVIS | 0 | 0 | 0 | 10 | 0 | 0 | 1.012 | 0 | 0 |
| KINGMAN TAP | 843968 | 654085 | 189883 | 10 | | | | 1,898,830 | 4,040 |
| CYPRUS WELLFIELD | 395031 | 88317 | 306714 | 10 | 3,067,140 | 4,160 | 1.006 | 3,085,543 | 4,185 |
| ROUND VALLEY | 1404538 | 969600 | 434938 | 10 | | | | 4,349,380 | 3,460 |
| AIRPORT FROM DAVIS | 321 | 240 | 81 | 28000 | | | | 2,268,000 | 11,032 |
| TOPOCK | 206406 | 121716 | 84690 | 100 | | | | 8,469,000 | 18,200 |
| METER ADJUSTMENTS (See p A-4-4) | | | | | | | | 3,161,663 | |
| | | | | | METERED SUBTOTAL | | | 63,802,116 | 126,817 |
| **LESS LOADS SERVED UNDER OTHER AGREEMENTS:** | | | | | | | | | |
| MEC WHEELING LOAD | | | | | | | | 0 | 0 |
| MEC INTERNAL LOAD | | | | | | | | 160,000 | 0 |
| MEMBER JMP LOAD of MEC | | | | | | | | 0 | 0 |
| CSP JMP LOAD of MEC | | | | | | | | 0 | 0 |
| | | | | | OTHER LOADS SUBTOTAL | | | 160,000 | 0 |
| PLUS SCHEDULED MEMBER AEPCO SALES | | | | | | | | 1,280,000 | |
| **TOTAL BILLING DEMAND & TOTAL ENERGY** | | | | | | | | 64,922,116 | 126,817 |

POWER FACTOR ADJUSTMENT: $\left[\frac{\text{KW}}{\text{POWER FACTOR}}\right] \times .9$

| | METERED KW | POWER FACTOR | ADJUSTED KW | POWER FACTOR ADJUSTMENT |
|---|---|---|---|---|
| RIVIERA TOTAL | 83,400 | 0.95 | 0 | 0 |
| BILL WILLIAMS | 698 | 0.87 | 722 | 24 |
| BULLHEAD / DAVIS | 0 | 1.00 | 0 | 0 |
| KINGMAN TAP | 4,000 | 0.96 | 0 | 0 |
| CYPRUS WELLFIELD | 4,180 | 0.91 | 0 | 0 |
| ROUND VALLEY | 5,700 | 0.89 | 5764 | 64 |
| AIRPORT FROM DAVIS | 11,172 | 0.98 | 0 | 0 |
| TOPOCK | 18,000 | 0.97 | 0 | 0 |
| TOTAL POWER FACTOR MEC PEAK | 127,150 | 0.95 | 6,486 | 88 |
| TOTAL POWER FACTOR coincident | 126,782 | 0.95 | 0 | 0 |

AEPCO PEAK ON 07/01/00 AT 17:00 HOURS

LOAD FACTOR 68.61% BASED ON ACTUAL KWH & KW USED.

MEC NC PEAK OF 127,185 KW ON 07/01/00 18:00 HOURS

# SAMPLE BILL

MOHAVE ELECTRIC COOPERATIVE, INC.

METER ADJUSTMENT SHEET

JULY 2000

| | | | | | KWH | KW |
|---|---|---|---|---|---|---|
| BIG BEND -Yearly Calibration | | | | | (3,654) | |
| MEDLIN -Yearly Calibration | | | | | 4,613 | |
| W. V. / SWAN -Yearly Calibration & Replace analog cards | | | | | 2,204 | |
| ERA FROM DAVIS -Yrly Cal,Replace memory chip,out of service when working on WV Swan | | | | | (20,400) | |
| ERA TO AIRPORT -Yrly Cal, Replace memory chip, out of service when working on WV Swan | | | | | 13,900 | |
| Meter zeroed by Western 7/13 | | | | | | |
| AIRPORT FROM DAVIS | 113 | 0 | 113 | 28000 | 3,164,000 | |
| AIRPORT FROM DAVIS -Meter Adj | | | | | 1,000 | |
| TOTAL | | | | | 3,161,663 | 0 |

# SAMPLE BILL

MOHAVE ELECTRIC COOPERATIVE, INC.

Power Prepayment Program Worksheet

**BILLING PERIOD: July, 2000**

| Prepayment Date | Estimated Due Date | Estim # Days | Prepayment Amount | Interest Rate | Daily Accrued Interest | Actual Due Date | Actual # of Days | Total Prepayment + Interest |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | $0.00 |
| | | | | | | | | $0.00 |
| TOTAL | | | | | | | | $0.00 |

**SAMPLE BILL**
MOHAVE ELECTRIC COOPERATIVE, INC
RATE SCHEDULE A
DEMAND DATA WORKSHEET - BILLING PERIOD - JULY 2000

| DATE | "1999" Day of Week | A<br>MEC Metered kW Demand @ AEPCO Peak | B<br>MEC AEPCO Sales Metered or Scheduled @ AEPCO Pk | C = A + B<br>Total @ AEPCO Peak | D<br>Resource Schedules for MEC Wheeling & Member JMP, and CSP JMP Loads @ AEPCO Pk | E = C - D<br>Load for AEPCO & Member Resources @ AEPCO Peak | F<br>Member Resource Schedule for MEC Internal Loads @ AEPCO Pk | G = E - F<br>AEPCO Resource Used @ AEPCO Peak (Member Billing Demand) | H = G - AC<br>If G > AC, Schedule A Demand Overrun of AC @ AEPCO Peak | If MR sched>0 and if G < Profile Capacity<br>Demand for Minimum O&M Charge of Section 7.2.4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MW | MW | MW | MW | MW | MW | MW | MW | MW |
| 1 | Th | 126.817 | 0.000 | 126.817 | 0.000 | 126.817 | 0.000 | 126.817 | 4.017 | 0.000 |
| 2 | F | 123.700 | 0.000 | 123.700 | 0.000 | 123.700 | 0.000 | 123.700 | 0.900 | 0.000 |
| 3 | S | 110.300 | 0.000 | 110.300 | 0.000 | 110.300 | 0.000 | 110.300 | 0.000 | 0.000 |
| 4 | Su | 117.200 | 0.000 | 117.200 | 0.000 | 117.200 | 0.000 | 117.200 | 0.000 | 0.000 |
| 5 | M | 122.800 | 0.000 | 122.800 | 0.000 | 122.800 | 0.000 | 122.800 | 0.000 | 0.000 |
| 6 | T | 115.500 | 0.000 | 115.500 | 0.000 | 115.500 | 0.000 | 115.500 | 0.000 | 0.000 |
| 7 | W | 112.700 | 0.000 | 112.700 | 0.000 | 112.700 | 0.000 | 112.700 | 0.000 | 0.000 |
| 8 | Th | 107.600 | 0.000 | 107.600 | 0.000 | 107.600 | 0.000 | 107.600 | 0.000 | 0.000 |
| 9 | F | 111.100 | 0.000 | 111.100 | 0.000 | 111.100 | 0.000 | 111.100 | 0.000 | 0.000 |
| 9 | S | 120.500 | 0.000 | 120.500 | 0.000 | 120.500 | 0.000 | 120.500 | 0.000 | 0.000 |
| [illegible] | Su | 104.700 | 0.000 | 104.700 | 0.000 | 104.700 | 0.000 | 104.700 | 0.000 | 0.000 |
| 12 | M | 83.900 | 0.000 | 83.900 | 0.000 | 83.900 | 0.000 | 83.900 | 0.000 | 0.000 |
| 13 | T | 99.500 | 0.000 | 99.500 | 0.000 | 99.500 | 0.000 | 99.500 | 0.000 | 0.000 |
| 14 | W | 112.300 | 0.000 | 112.300 | 0.000 | 112.300 | 0.000 | 112.300 | 0.000 | 0.000 |
| 15 | Th | 112.000 | 5.000 | 117.000 | 0.000 | 117.000 | 0.000 | 117.000 | 0.000 | 0.000 |
| 16 | F | 112.700 | 5.000 | 117.700 | 0.000 | 117.700 | 0.000 | 117.700 | 0.000 | 0.000 |
| 17 | S | 109.300 | 5.000 | 114.300 | 0.000 | 114.300 | 0.000 | 114.300 | 0.000 | 0.000 |
| 18 | Su | 108.300 | 5.000 | 113.300 | 0.000 | 113.300 | 0.000 | 113.300 | 0.000 | 0.000 |
| 19 | M | 110.400 | 5.000 | 115.400 | 0.000 | 115.400 | 0.000 | 115.400 | 0.000 | 0.000 |
| 20 | T | 114.700 | 5.000 | 119.700 | 0.000 | 119.700 | 0.000 | 119.700 | 0.000 | 0.000 |
| 21 | W | 115.700 | 5.000 | 120.700 | 0.000 | 120.700 | 0.000 | 120.700 | 0.000 | 0.000 |
| 22 | Th | 114.200 | 5.000 | 119.200 | 0.000 | 119.200 | 10.000 | 109.200 | 0.000 | 10.000 |
| 23 | F | 110.900 | 5.000 | 115.900 | 0.000 | 115.900 | 0.000 | 115.900 | 0.000 | 0.000 |
| 24 | S | 118.200 | 5.000 | 123.200 | 0.000 | 123.200 | 0.000 | 123.200 | 0.400 | 0.000 |
| 25 | Su | 119.100 | 5.000 | 124.100 | 0.000 | 124.100 | 0.000 | 124.100 | 1.300 | 0.000 |
| 26 | M | 122.500 | 0.000 | 122.500 | 0.000 | 122.500 | 0.000 | 122.500 | 0.000 | 0.000 |
| 27 | T | 86.800 | 5.000 | 91.800 | 0.000 | 91.800 | 0.000 | 91.800 | 0.000 | 0.000 |
| 28 | W | 103.700 | 5.000 | 108.700 | 0.000 | 108.700 | 0.000 | 108.700 | 0.000 | 0.000 |
| 29 | Th | 103.100 | 5.000 | 108.100 | 0.000 | 108.100 | 0.000 | 108.100 | 0.000 | 0.000 |
| 30 | F | 116.100 | 5.000 | 121.100 | 0.000 | 121.100 | 0.000 | 121.100 | 0.000 | 0.000 |
| 31 | S | 121.600 | 5.000 | 126.600 | 0.000 | 126.600 | 0.000 | 126.600 | 3.800 | 0.000 |
| | | | | | | | | | Maximum Value | Minimum Value |
| Maximums | | 126.817 | 5.000 | 126.817 | 0.000 | 126.817 | 10.000 | 126.817 | 4.017 | 0.000 |

**MEC ALLOCATED CAPACITY (MW)** **122.800** **0** A

**Schedule A Demand Overrun = highest over AC at Peak (MW & %)** **4.017**
**3.271%**

**MEC AEPCO Profile Capacity = Min O&M Capacity with MR sched (MW)** **122.800**
**Schedule B Capacity Available (AC less Profile Capacity) (MW)** **0**

NOTE A: Minimum demand for O&M is billed only to extent Sched A Billing Demand is caused to be less than MEC AEPCO Profile Capacity by Member scheduling its Member Resources instead of using its AC.

**SAMPLE BILL**
MOHAVE ELECTRIC COOPERATIVE, INC
SCHEDULE B
DEMAND DATA WORKSHEET - BILLING PERIOD - JULY 2000

| DAY | *1999* Day of Week | A<br>MEC Metered kW - Demand @ MEC Peak<br>MW | B<br>MEC AEPCO Sales Metered or Scheduled @ MEC Peak<br>MW | C = A + B<br>Total @ MEC Peak<br>MW | D<br>Resource Schedules for MEC Wheeling Load, Member JMP and CSP JMP Loads of MEC @ MEC Peak<br>MW | E = C - D<br>Load for AEPCO & Member Revenues @ MEC Peak<br>MW | F<br>Member Resource Schedule for MEC Internal Loads @ MEC Peak<br>MW | G = E - F<br>AEPCO Resource Used @ MEC Peak (Schedule B Demand)<br>MW | H = G - AC<br>IF G > AC, Schedule B Demand Overrun of AC @ MEC Peak<br>MW |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Th | 127.150 | 0.000 | 127.150 | 0.000 | 127.150 | 0.000 | 127.150 | 4.350 |
| 2 | F | 123.756 | 0.000 | 123.756 | 0.000 | 123.756 | 0.000 | 123.756 | 0.956 |
| 3 | S | 117.942 | 0.000 | 117.942 | 0.000 | 117.942 | 0.000 | 117.942 | 0.000 |
| 4 | Su | 119.010 | 0.000 | 119.010 | 0.000 | 119.010 | 0.000 | 119.010 | 0.000 |
| 5 | M | 126.006 | 0.000 | 126.006 | 0.000 | 126.006 | 0.000 | 126.006 | 3.206 |
| 6 | T | 125.936 | 0.000 | 125.936 | 0.000 | 125.936 | 0.000 | 125.936 | 3.136 |
| 7 | W | 114.808 | 0.000 | 114.808 | 0.000 | 114.808 | 0.000 | 114.808 | 0.000 |
| 8 | Th | 108.080 | 0.000 | 108.080 | 0.000 | 108.080 | 0.000 | 108.080 | 0.000 |
| 9 | F | 117.264 | 0.000 | 117.264 | 0.000 | 117.264 | 0.000 | 117.264 | 0.000 |
| 10 | S | 123.184 | 0.000 | 123.184 | 0.000 | 123.184 | 0.000 | 123.184 | 0.384 |
| [illegible] | Su | 104.742 | 0.000 | 104.742 | 0.000 | 104.742 | 0.000 | 104.742 | 0.000 |
| 12 | M | 85.304 | 0.000 | 85.304 | 0.000 | 85.304 | 0.000 | 85.304 | 0.000 |
| 13 | T | 100.086 | 0.000 | 100.086 | 0.000 | 100.086 | 0.000 | 100.086 | 0.000 |
| 14 | W | 112.496 | 0.000 | 112.496 | 0.000 | 112.496 | 0.000 | 112.496 | 0.000 |
| 15 | Th | 112.494 | 5.000 | 117.494 | 0.000 | 117.494 | 0.000 | 117.494 | 0.000 |
| 16 | F | 113.356 | 5.000 | 118.356 | 0.000 | 118.356 | 0.000 | 118.356 | 0.000 |
| 17 | S | 112.084 | 5.000 | 117.084 | 0.000 | 117.084 | 0.000 | 117.084 | 0.000 |
| 18 | Su | 110.660 | 5.000 | 115.660 | 0.000 | 115.660 | 0.000 | 115.660 | 0.000 |
| 19 | M | 115.676 | 5.000 | 120.676 | 0.000 | 120.676 | 0.000 | 120.676 | 0.000 |
| 20 | T | 115.380 | 5.000 | 120.380 | 0.000 | 120.380 | 0.000 | 120.380 | 0.000 |
| 21 | W | 115.880 | 5.000 | 120.880 | 0.000 | 120.880 | 0.000 | 120.880 | 0.000 |
| 22 | Th | 119.964 | 5.000 | 124.964 | 0.000 | 124.964 | 10.000 | 114.964 | 0.000 |
| 23 | F | 117.594 | 5.000 | 122.594 | 0.000 | 122.594 | 0.000 | 122.594 | 0.000 |
| 24 | S | 120.238 | 5.000 | 125.238 | 0.000 | 125.238 | 0.000 | 125.238 | 2.438 |
| 25 | Su | 119.576 | 5.000 | 124.576 | 0.000 | 124.576 | 0.000 | 124.576 | 1.776 |
| 26 | M | 122.700 | 0.000 | 122.700 | 0.000 | 122.700 | 0.000 | 122.700 | 0.000 |
| 27 | T | 90.242 | 5.000 | 95.242 | 0.000 | 95.242 | 0.000 | 95.242 | 0.000 |
| 28 | W | 104.126 | 5.000 | 109.126 | 0.000 | 109.126 | 0.000 | 109.126 | 0.000 |
| 29 | Th | 104.966 | 5.000 | 109.966 | 0.000 | 109.966 | 0.000 | 109.966 | 0.000 |
| 30 | F | 116.964 | 5.000 | 121.964 | 0.000 | 121.964 | 0.000 | 121.964 | 0.000 |
| 31 | S | 122.696 | 5.000 | 127.696 | 0.000 | 127.696 | 0.000 | 127.696 | 4.896 |
| | | | | | | | | | Maximum Value |
| | | 127.150 | 5.000 | 127.696 | 0.000 | 127.696 | 10.000 | 127.696 | 4.896 |
| | | | | | | | | **Allocated Capacity (MW)** | **122.800** |
| | | | | | | | | **Schedule B Demand Overrun = greater of Sched A Overrun or Sched B Demand Overrun (MW & %)** | **4.896** |
| | | | | | | | | | **3.987%** |

NOTE: PAGES A-4-8-1 to A-4-8-31 Compute Energy Charges for Schedule B ENERGY PROFILE Overruns of each day of the Billing Period.
NOTE: PAGES A-4-9-1 through A-4-9-31 Compute Energy Charges for Schedule B Minimum Energy of each day of the Billing Period.

**SAMPLE BILL -SCHEDULE B**
MOHAVE ELECTRIC COOPERATIVE, INC
MAXIMUM AND MINIMUM BASE CAPACITY SUMMARY
*DAYS OF BILLING PERIOD JULY 2000*

| | A | B | C | D = A + B + C | | E | F | G | H = E + F + G |
|---|---|---|---|---|---|---|---|---|---|
| HOUR ENDING | MEC Share of AEPCO Maximum Coal Capacity (see Table B-4) | MEC Share of AEPCO Must-Run Hydro Capacity (see Table B-3-1) | MEC Share of PacifiCorp Purchase Capacity (see Table B-3-2) | MEC Share of AEPCO Maximum Base Capacity | | MEC Share of AEPCO Minimum Coal Capacity (see Table B-2) | MEC Share of AEPCO Must-Run Hydro Capacity (see Table B-3-1) | MEC Share of PacifiCorp Purchase Capacity (see Table B-3-2) | MEC share of AEPCO Minimum Base Capacity |
| | MW | MW | MW | MW | | MW | MW | MW | MW |
| 1 | 51.70 | 4.66 | 0.00 | 56.36 | (A) | 42.30 | 4.66 | 0.00 | 46.96 |
| 2 | 51.70 | 4.66 | 0.00 | 56.36 | | 42.30 | 4.66 | 0.00 | 46.96 |
| 3 | 51.70 | 4.66 | 0.00 | 56.36 | | 42.30 | 4.66 | 0.00 | 46.96 |
| 4 | 51.70 | 4.66 | 0.00 | 56.36 | | 42.30 | 4.66 | 0.00 | 46.96 |
| 5 | 51.70 | 4.66 | 0.00 | 56.36 | | 42.30 | 4.66 | 0.00 | 46.96 |
| 6 | 51.70 | 4.66 | 0.00 | 56.36 | | 42.30 | 4.66 | 0.00 | 46.96 |
| 7 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 8 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 9 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 10 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 11 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 12 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 13 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 14 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 15 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 16 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 17 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 18 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 19 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 20 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 21 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 22 | 51.70 | 11.69 | 17.50 | 80.89 | | 42.30 | 11.69 | 17.50 | 71.49 |
| 23 | 51.70 | 4.66 | 0.00 | 56.36 | | 42.30 | 4.66 | 0.00 | 46.96 |
| 24 | 51.70 | 4.66 | 0.00 | 56.36 | | 42.30 | 4.66 | 0.00 | 46.96 |
| TOTAL | 1,240.80 | 224.37 | 280.00 | 1,745.17 | | 1,015.20 | 224.37 | 280.00 | 1,519.57 |

(A) SUNDAY AND HOLIDAY IS ALL OFF-PEAK AND WOULD HAVE THESE VALUES FOR MIN AND MAX BASE CAPACITY FOR 24 HOURS

DATE= 7/1

**SAMPLE BILL - SCHEDULE B**

MOHAVE ELECTRIC COOPERATIVE, INC

OVERRUN ENERGY ADJUSTMENT SUMMARY FOR DAY 1 OF BILLING PERIOD - JULY 1999 LOAD, JULY 2000 AC

MEC LOAD over Allocated Capacity at AEPCO PEAK HOUR and Another HOUR - DAY 1

| DOW = Th | A | | B | C | D | E= A-B-C+D | F | G =(F - E)> 0 | I | | H = G * I |
|---|---|---|---|---|---|---|---|---|---|---|---|
| HOUR ENDING | MEC Metered kWh - Energy MWH | | Energy Received for MEC Wheeling Load, Member JMP & CSP JMP Loads MWH | Energy from Member Resource for MEC Internal Loads MWH | Energy Schedule for MEC AEPCO Sale MWH | TOTAL Energy from AEPCO Resources Supplied to MEC MWH | MEC AEPCO Profile Energy Available (Exh 3, Table B-6, Day 13) MWH | Schedule B Overrun Energy MWH | *greater of Rate Schedule A or* HIGHEST Resource COST $/MWH | | Schedule B Overrun Energy Charge $ |
| 1 | 73.58 | D | 0.00 | 0.00 | 0.00 | 73.58 | 73.40 | 0.18 | 30.88 | A | $5.65 |
| 2 | 68.76 | D | 0.00 | 0.00 | 0.00 | 68.76 | 68.80 | 0.00 | 30.88 | A | $0.00 |
| 3 | 64.36 | D | 0.00 | 0.00 | 0.00 | 64.36 | 65.10 | 0.00 | 30.88 | A | $0.00 |
| 4 | 61.46 | D | 0.00 | 0.00 | 0.00 | 61.46 | 62.10 | 0.00 | 30.88 | A | $0.00 |
| 5 | 60.19 | D | 0.00 | 0.00 | 0.00 | 60.19 | 60.60 | 0.00 | 30.88 | A | $0.00 |
| 6 | 59.25 | D | 0.00 | 0.00 | 0.00 | 59.25 | 60.20 | 0.00 | 30.88 | A | $0.00 |
| 7 | 62.16 | D | 0.00 | 0.00 | 0.00 | 62.16 | 80.80 | 0.00 | 28.39 | A | $0.00 |
| 8 | 70.17 | D | 0.00 | 0.00 | 0.00 | 70.17 | 80.80 | 0.00 | 27.67 | A | $0.00 |
| 9 | 80.16 | D | 0.00 | 0.00 | 0.00 | 80.16 | 80.80 | 0.00 | 26.60 | A | $0.00 |
| 10 | 90.47 | D | 0.00 | 0.00 | 0.00 | 90.47 | 89.00 | 1.47 | 26.46 | A | $38.84 |
| 11 | 99.49 | D | 0.00 | 0.00 | 0.00 | 99.49 | 98.40 | 1.09 | 26.43 | A | $28.81 |
| 12 | 106.38 | D | 0.00 | 0.00 | 0.00 | 106.38 | 106.90 | 0.00 | 61.75 | B | $0.00 |
| 13 | 113.62 | D | 0.00 | 0.00 | 0.00 | 113.62 | 114.20 | 0.00 | 61.75 | B | $0.00 |
| 14 | 119.52 | D | 0.00 | 0.00 | 0.00 | 119.52 | 118.80 | 0.72 | 34.24 | C | $24.72 |
| 15 | 122.44 | D | 0.00 | 0.00 | 0.00 | 122.44 | 120.40 | 2.04 | 34.24 | C | $69.99 |
| 16 | 124.90 | D | 0.00 | 0.00 | 0.00 | 124.90 | 122.80 | 2.10 | 34.24 | C | $72.04 |
| 17 | 126.64 | D | 0.00 | 0.00 | 0.00 | 126.64 | 122.40 | 4.24 | 34.24 | C | $145.11 |
| 18 | 126.39 | D | 0.00 | 0.00 | 0.00 | 126.39 | 120.00 | 6.39 | 34.24 | C | $218.90 |
| 19 | 124.78 | D | 0.00 | 0.00 | 0.00 | 124.78 | 119.60 | 5.18 | 32.22 | B | $166.90 |
| 20 | 118.55 | D | 0.00 | 0.00 | 0.00 | 118.55 | 114.60 | 3.95 | 32.74 | B | $129.45 |
| 21 | 113.08 | D | 0.00 | 0.00 | 0.00 | 113.08 | 110.30 | 2.78 | 35.52 | B | $98.64 |
| 22 | 104.33 | D | 0.00 | 0.00 | 0.00 | 104.33 | 101.80 | 2.53 | 38.99 | B | $98.72 |
| 23 | 93.70 | D | 0.00 | 0.00 | 0.00 | 93.70 | 91.40 | 2.30 | 26.60 | A | $61.18 |
| 24 | 84.13 | D | 0.00 | 0.00 | 0.00 | 84.13 | 82.40 | 1.73 | 28.39 | A | $49.11 |
| TOTAL | 2,268.53 | | 0.000 | | 0.00 | 2,268.53 | 2,265.60 | 36.715 | | | $1,208.07 |
| | | | | | | | | | Overrun $/MWh | | 32.904 |

A CC ON LINE
B GT #3 ON LINE
C GT #2 ON LINE
D Should be adjusted for losses at 3 locations

**MRT NOTE: SIMILAR WORKSHEETS WOULD BE PREPARED FOR ALL DAYS OF EACH MONTH**

DATE=7/26

**SAMPLE BILL - SCHEDULE B**
MOHAVE ELECTRIC COOPERATIVE, INC
OVERRUN ENERGY ADJUSTMENT SUMMARY FOR DAY 26 - JULY 1999 LOAD, JULY 2000 AC
TYPICAL MONDAY SCHEDULE A ENERGY AVAILABLE VERSUS DAY 26 OF JULY 1999

| DOW=M | A | | B | C | D | E= A-B-C+D | F | G = F - E > 0 | | I | H = G * I |
|---|---|---|---|---|---|---|---|---|---|---|---|
| HOUR ENDING | MEC Metered kWh - Energy MWH | | Energy Received for MEC Wheeling Load, Member JMP & CSP JMP Loads MWH | Energy from Member Resource for MEC Internal Loads MWH | Energy Schedule for MEC AEPCO Sale MWH | TOTAL Energy from AEPCO Resources Supplied to MEC MWH | MEC AEPCO Profile Energy Available (Exh 3, Table B-6, Day 13) MWH | Schedule B Overrun Energy MWH | *greater of Rate Schedule A or* HIGHEST Resource COST $/MWH | | Schedule B Overrun Energy Charge $ |
| 1 | 74.07 | D | 0.00 | 0.00 | 0.00 | 74.07 | 66.20 | 7.87 | 28.27 | A | $222.60 |
| 2 | 69.59 | D | 0.00 | 0.00 | 0.00 | 69.59 | 62.20 | 7.39 | 28.27 | A | $208.80 |
| 3 | 66.37 | D | 0.00 | 0.00 | 0.00 | 66.37 | 59.10 | 7.27 | 28.27 | A | $205.41 |
| 4 | 63.18 | D | 0.00 | 0.00 | 0.00 | 63.18 | 56.80 | 6.38 | 28.27 | A | $180.31 |
| 5 | 61.37 | D | 0.00 | 0.00 | 0.00 | 61.37 | 56.30 | 5.07 | 28.27 | A | $143.44 |
| 6 | 60.73 | D | 0.00 | 0.00 | 0.00 | 60.73 | 56.30 | 4.43 | 28.27 | A | $125.15 |
| 7 | 63.17 | D | 0.00 | 0.00 | 0.00 | 63.17 | 80.80 | 0.00 | 28.27 | A | $0.00 |
| 8 | 71.41 | D | 0.00 | 0.00 | 0.00 | 71.41 | 80.80 | 0.00 | 28.27 | A | $0.00 |
| 9 | 80.65 | D | 0.00 | 0.00 | 0.00 | 80.65 | 80.80 | 0.00 | 25.33 | A | $0.00 |
| 10 | 89.58 | D | 0.00 | 0.00 | 0.00 | 89.58 | 80.80 | 8.78 | 24.54 | A | $215.53 |
| 11 | 97.59 | D | 0.00 | 0.00 | 0.00 | 97.59 | 87.50 | 10.09 | 24.17 | A | $243.78 |
| 12 | 105.50 | D | 0.00 | 0.00 | 0.00 | 105.50 | 94.50 | 11.00 | 24.24 | A | $266.52 |
| 13 | 111.58 | D | 0.00 | 0.00 | 0.00 | 111.58 | 100.30 | 11.28 | 24.36 | A | $274.71 |
| 14 | 116.18 | D | 0.00 | 0.00 | 0.00 | 116.18 | 104.90 | 11.28 | 24.36 | A | $274.68 |
| 15 | 119.84 | D | 0.00 | 0.00 | 0.00 | 119.84 | 108.20 | 11.64 | 24.24 | A | $282.23 |
| 16 | 122.31 | D | 0.00 | 0.00 | 0.00 | 122.31 | 110.50 | 11.81 | 24.23 | A | $286.18 |
| 17 | 128.00 | D | 0.00 | 0.00 | 0.00 | 128.00 | 111.20 | 16.80 | 24.17 | A | $406.06 |
| 18 | 122.00 | D | 0.00 | 0.00 | 0.00 | 122.00 | 109.60 | 12.40 | 24.54 | A | $304.37 |
| 19 | 118.30 | D | 0.00 | 0.00 | 0.00 | 118.30 | 106.20 | 12.10 | 25.33 | A | $306.59 |
| 20 | 110.04 | D | 0.00 | 0.00 | 0.00 | 110.04 | 100.70 | 9.34 | 25.33 | A | $236.51 |
| 21 | 106.01 | D | 0.00 | 0.00 | 0.00 | 106.01 | 96.40 | 9.61 | 25.99 | A | $249.76 |
| 22 | 97.23 | D | 0.00 | 0.00 | 0.00 | 97.23 | 89.00 | 8.23 | 26.97 | A | $221.86 |
| 23 | 86.46 | D | 0.00 | 0.00 | 0.00 | 86.46 | 80.10 | 6.36 | 25.99 | A | $165.27 |
| 24 | 78.04 | D | 0.00 | 0.00 | 0.00 | 78.04 | 72.50 | 5.54 | 28.27 | A | $156.67 |
| TOTAL | 2,219.19 | | 0.00 | | 0.00 | 2,219.19 | 2,051.70 | 194.657 | | | $4,976.43 |
| | | | | | | | | | Overrun $/MWh | | 25.565 |

A CC ON LINE
B GT #3 ON LINE
C GT #2 ON LINE
D Should be adjusted for losses at 3 locations

Date=7/31

**SAMPLE BILL - SCHEDULE B**
MOHAVE ELECTRIC COOPERATIVE, INC
OVERRUN ENERGY ADJUSTMENT SUMMARY FOR DAY 31 - JULY 1999 LOAD, JULY 2000 AC
TYPICAL SATURDAY WITH MEC PEAK HOUR SALE - JULY 31

| DOW = S | A | | B | C | D | E= A-B-C+D | F | G = F - E > 0 | I | | H = G * I |
|---|---|---|---|---|---|---|---|---|---|---|---|
| HOUR ENDING | MEC Metered kWh - Energy MWH | | Energy Received for MEC Wheeling Load, Member JMP & CSP JMP Loads MWH | Energy from Member Resource for MEC Internal Loads MWH | Energy Schedule for MEC AEPCO Sale MWH | TOTAL Energy from AEPCO Resources Supplied to MEC MWH | MEC AEPCO Profile Energy Available (Exh 3, Table B-6, Day 13) MWH | Schedule B Overrun Energy MWH | *greater of Rate Schedule A or* HIGHEST Resource COST $/MWH | | Schedule B Overrun Energy Charge $ |
| 1 | 71.11 | D | 0.00 | 0.00 | 0.00 | 71.11 | 68.10 | 3.01 | 22.17 | A | $66.82 |
| 2 | 66.01 | D | 0.00 | 0.00 | 0.00 | 66.01 | 63.60 | 2.41 | 20.33 | A | $48.95 |
| 3 | 63.00 | D | 0.00 | 0.00 | 0.00 | 63.00 | 60.00 | 3.00 | 20.33 | A | $61.01 |
| 4 | 60.43 | D | 0.00 | 0.00 | 0.00 | 60.43 | 57.40 | 3.03 | 20.33 | A | $61.58 |
| 5 | 59.39 | D | 0.00 | 0.00 | 0.00 | 59.39 | 56.30 | 3.09 | 20.33 | A | $62.90 |
| 6 | 58.52 | D | 0.00 | 0.00 | 0.00 | 58.52 | 56.30 | 2.22 | 20.33 | A | $45.11 |
| 7 | 58.96 | D | 0.00 | 0.00 | 5.00 | 63.96 | 80.80 | 0.00 | 20.33 | A | $0.00 |
| 8 | 65.40 | D | 0.00 | 0.00 | 5.00 | 70.40 | 80.80 | 0.00 | 20.33 | A | $0.00 |
| 9 | 74.52 | D | 0.00 | 0.00 | 5.00 | 79.52 | 80.80 | 0.00 | 20.33 | A | $0.00 |
| 10 | 84.93 | D | 0.00 | 0.00 | 5.00 | 89.93 | 80.80 | 9.13 | 20.33 | A | $185.55 |
| 11 | 94.69 | D | 0.00 | 0.00 | 5.00 | 99.69 | 89.10 | 10.59 | 23.92 | A | $253.38 |
| 12 | 102.94 | D | 0.00 | 0.00 | 5.00 | 107.94 | 96.30 | 11.64 | 26.14 | A | $304.37 |
| 13 | 109.59 | D | 0.00 | 0.00 | 5.00 | 114.59 | 102.00 | 12.59 | 27.01 | A | $340.16 |
| 14 | 114.98 | D | 0.00 | 0.00 | 5.00 | 119.98 | 106.50 | 13.48 | 27.01 | A | $364.09 |
| 15 | 118.93 | D | 0.00 | 0.00 | 5.00 | 123.93 | 109.40 | 14.53 | 27.01 | A | $392.46 |
| 16 | 121.45 | D | 0.00 | 0.00 | 5.00 | 126.45 | 111.80 | 14.65 | 27.01 | A | $395.78 |
| 17 | 122.54 | D | 0.00 | 0.00 | 5.00 | 127.54 | 112.40 | 15.14 | 27.01 | A | $408.90 |
| 18 | 121.73 | D | 0.00 | 0.00 | 5.00 | 126.73 | 111.50 | 15.23 | 27.01 | A | $411.25 |
| 19 | 118.09 | D | 0.00 | 0.00 | 5.00 | 123.09 | 108.20 | 14.89 | 27.01 | A | $402.29 |
| 20 | 110.45 | D | 0.00 | 0.00 | 5.00 | 115.45 | 102.10 | 13.35 | 27.01 | A | $360.66 |
| 21 | 103.94 | D | 0.00 | 0.00 | 5.00 | 108.94 | 97.50 | 11.44 | 27.01 | A | $308.91 |
| 22 | 94.53 | D | 0.00 | 0.00 | 5.00 | 99.53 | 89.90 | 9.63 | 27.01 | A | $259.97 |
| 23 | 84.90 | D | 0.00 | 0.00 | 0.00 | 84.90 | 81.80 | 3.10 | 27.01 | A | $83.70 |
| 24 | 76.13 | D | 0.00 | 0.00 | 0.00 | 76.13 | 74.30 | 1.83 | 27.01 | A | $49.29 |
| TOTAL | 2,157.16 | | 0.00 | | 80.00 | 2,237.16 | 2,077.70 | 187.984 | | | $4,867.17 |
| | | | | | | | | | Overrun $/MWh | | 25.891 |

A CC ON LINE
C GT #3 ON LINE
B GT #2 ON LINE
D Should be adjusted for losses at 3 locations

**MRT NOTE: SIMILAR WORKSHEETS WOULD BE PREPARED FOR ALL DAYS OF EACH MONTH**

Date=7/22

**SAMPLE BILL - SCHEDULE B**

MOHAVE ELECTRIC COOPERATIVE, INC

MINIMUM ENERGY ADJUSTMENT SUMMARY FOR DAY 22 PERIOD - JULY 1999 LOAD, JULY 2000 AC

MEC SUPPLIES ENERGY FOR PART OF LOAD ON DAY 22

| dow = Th | A | | B | C | D | E= A-B-C+D | F | G Min C,F-E | H | I = G - H | J | K = I * J |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HOUR ENDING | MEC Metered kWh - Energy | | Energy Received for MEC Wheeling Load, Member JMP & CSP JMP Loads | Energy from Member Resource for Member Internal Loads | Energy Schedule for MEC Member AEPCO Sales | Energy from AC Supplied to MEC | MEC share of Minimum Base Capacity (see A-4-7) | "If MR > 0" Energy Below MEC Share of AEPCO Minimum Base Capacity | Energy from G sold to Others @ rate >= Schedule A E-rate | Energy not sold from MEC Share of Minimum Base Capacity | Schedule A Energy Rate less price to others, if less than Schedule A E-rate | Schedule B Minimum Energy Charge |
| | MWH | | MWH | MWH | MWH | MWH | MWH | MWH | MWH | MWH | $/MWH | $ |
| 1 | 65.47 | D | 0.00 | 0.00 | 0.00 | 65.47 | 46.96 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 2 | 60.81 | D | 0.00 | 0.00 | 0.00 | 60.81 | 46.96 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 3 | 57.26 | D | 0.00 | 0.00 | 0.00 | 57.26 | 46.96 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 4 | 54.04 | D | 0.00 | 0.00 | 0.00 | 54.04 | 46.96 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 5 | 52.40 | D | 0.00 | 0.00 | 0.00 | 52.40 | 46.96 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 6 | 51.99 | D | 0.00 | 0.00 | 0.00 | 51.99 | 46.96 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 7 | 54.39 | D | 0.00 | 10.00 | 0.00 | 44.39 | 71.49 | 10.00 | 0.00 | 10.00 | 15.03 | $150.30 |
| 8 | 61.36 | D | 0.00 | 10.00 | 0.00 | 51.36 | 71.49 | 10.00 | 0.00 | 10.00 | 15.03 | $150.30 |
| [illegible] | 69.45 | D | 0.00 | 10.00 | 0.00 | 59.45 | 71.49 | 10.00 | 0.00 | 10.00 | 15.03 | $150.30 |
| [illegible] | 77.35 | D | 0.00 | 10.00 | 0.00 | 67.35 | 71.49 | 4.14 | 0.00 | 4.14 | 15.03 | $62.24 |
| [illegible] | 86.50 | D | 0.00 | 10.00 | 0.00 | 76.50 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 12 | 95.72 | D | 0.00 | 10.00 | 0.00 | 85.72 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 13 | 102.73 | D | 0.00 | 10.00 | 0.00 | 92.73 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 14 | 108.93 | D | 0.00 | 10.00 | 0.00 | 98.93 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 15 | 113.70 | D | 0.00 | 10.00 | 0.00 | 103.70 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 16 | 117.47 | D | 0.00 | 10.00 | 0.00 | 107.47 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 17 | 119.70 | D | 0.00 | 10.00 | 0.00 | 109.70 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 18 | 118.90 | D | 0.00 | 10.00 | 0.00 | 108.90 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 19 | 114.80 | D | 0.00 | 10.00 | 0.00 | 104.80 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 20 | 108.24 | D | 0.00 | 10.00 | 0.00 | 98.24 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 21 | 102.39 | D | 0.00 | 10.00 | 0.00 | 92.39 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 22 | 92.86 | D | 0.00 | 10.00 | 0.00 | 82.86 | 71.49 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 23 | 83.25 | D | 0.00 | 0.00 | 0.00 | 83.25 | 46.96 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| 24 | 74.95 | D | 0.00 | 0.00 | 0.00 | 74.95 | 46.96 | 0.00 | 0.00 | 0.00 | 15.03 | $0.00 |
| TOTAL | 2,044.66 | | 0.00 | 160.00 | 0.00 | 1,884.66 | 1,519.57 | 34.14 | 0.00 | 34.14 | | $513.14 |
| | | | | | | | | | | | Minimum $/MW | 15.030 |

D *Should be adjusted for losses at 3 locations*

**MRT NOTE: SIMILAR WORKSHEETS WOULD BE PREPARED FOR ALL DAYS OF EACH MONTH**

# Exhibit A-5 to Rate Schedule A
# Allocated Capacity Percentages (ACP)
# and Allocated Capacity (AC)

**Exhibit A-5 to Rate Schedule A**
**Allocated Capacity Percentages (ACP)**
**and Allocated Capacity (AC)**

ACP and AC DETERMINATION

An Allocated Capacity Percentage (ACP) has been developed for all Class A Members based on load forecasts from the 1996 Power Requirements Study (1996 PRS). The ACP is used to calculate the Allocated Capacity (AC) for the Partial Requirements Member. AEPCO, all AEPCO Class A Members, and RUS have approved the use of the 1996 PRS for planning purposes. The specific use of the 1996 PRS and forecast year 2000 were chosen as the basis for calculating the ACP because: (i) the annual coincident peak of AEPCO best matched the Existing Resources in forecast year 2000, and (ii) after forecast year 2000, AEPCO was projected to need additional Resources. The calculation used in determining the ACP is summarized in Appendix A to this Exhibit A-5. The ACP calculation utilizes the forecasted year 2000 monthly coincident peaks of the Class A Members, which are obtained by multiplying: (a) each Member's forecasted monthly non-coincident peak as identified in the 1996 PRS, by (b) a historical five-year average coincident factor. The resulting twelve monthly coincident peaks were summed both for each Class A Member and for all Class A Members. The ACP for each Class A Member represents the percentage quotient of (a) the sum of the monthly coincident peaks for that Class A Member divided by (b) the sum of the monthly coincident peaks for all Class A Members.

The ACP of the Partial Requirements Member is used to apportion AEPCO's Resources (after reductions for existing Power Sales Resources, associated losses and reserves) to determine the AC for the Partial Requirements Member. The AC for the Partial Requirements Member is calculated by: (1) determining the capacity (in MW) of the Existing Resources; (2) subtracting the Power Sales Resources as of the Closing Date, or as subsequently approved by the Partial Requirements Member, to determine adjusted capacity; (3) reducing the adjusted capacity for losses and reserves attributable to Power Sales to determine net AEPCO capacity attributable to the Class A Members; (4) multiplying such net capacity attributable to the Class A Members by the ACP of the Partial Requirements Member; and (5) reducing the resulting product for reserves and losses for the Partial Requirements Member.

The calculation of the AC of MEC through 2018 is depicted within Appendix B to this Exhibit A-5. As later power requirements studies become available, the AC of MEC for 2019, 2020 or until any later termination of the Agreement shall be calculated as set forth above, based on the ACP of the Partial Requirements Member.

## Appendix A to Exhibit A-5

## Schedule of Allocated Capacity Percentages

The schedule and calculation of the Allocated Capacity Percentages (ACP) is shown below:

| | | Allocated Capacity Percentage | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 1996 PRS Coincident Peak Demand Forecast - MW | | | | | | |
| *Ln.* | Year 2000 | Anza | Duncan | Graham | Mohave | Sulphur | Trico | Total |
| | | *Col. 1* | *2* | *3* | *4* | *5* | *6* | *7* |
| *1* | January | 6.0 | 3.2 | 15.9 | 70.5 | 80.8 | 57.1 | 233.5 |
| *2* | February | 5.6 | 2.9 | 15.1 | 62.7 | 76.9 | 48.7 | 211.9 |
| *3* | March | 5.8 | 2.9 | 15.7 | 60.4 | 70.9 | 44.2 | 199.9 |
| *4* | April | 4.8 | 2.8 | 15.8 | 64.4 | 66.8 | 44.0 | 198.7 |
| *5* | May | 5.2 | 3.1 | 19.5 | 80.2 | 77.3 | 44.4 | 229.7 |
| *6* | June | 6.6 | 3.8 | 25.0 | 105.4 | 87.3 | 49.3 | 277.4 |
| *7* | July | 6.7 | 4.3 | 26.3 | 127.0 | 92.6 | 67.4 | 324.4 |
| *8* | August | 8.0 | 4.4 | 25.0 | 130.5 | 88.7 | 69.0 | 325.6 |
| *9* | September | 7.7 | 3.8 | 22.3 | 120.8 | 85.1 | 60.9 | 300.7 |
| *10* | October | 6.5 | 3.2 | 16.8 | 106.5 | 78.0 | 52.7 | 263.7 |
| *11* | November | 5.7 | 3.0 | 16.1 | 79.5 | 77.0 | 49.1 | 230.4 |
| *12* | December | 5.8 | 3.4 | 16.2 | 76.4 | 79.2 | 51.4 | 232.4 |
| *13* | Annual Total | 74.6 | 40.8 | 229.8 | 1084.3 | 960.6 | 638.1 | 3028.2 |
| | *14* **Allocated Capacity %** | **2.5%** | **1.3%** | **7.6%** | **35.8%** | **31.7%** | **21.1%** | 100.0% |

**Notes:** Line 13 = sum of lines 1 through 12
Line 14, Col. 1 = Line 13, Col. 1 / Line 13, Col. 7
Line 14, Col. 2 = Line 13, Col. 2 / Line 13, Col. 7
Line 14, Col. 3 = Line 13, Col. 3 / Line 13, Col. 7
Line 14, Col. 4 = Line 13, Col. 4 / Line 13, Col. 7
Line 14, Col. 5 = Line 13, Col. 5 / Line 13, Col. 7
Line 14, Col. 6 = Line 13, Col. 6 / Line 13, Col. 7

**Appendix B to Exhibit A-5**
**Schedule of Allocated Capacity**

(SEE ATTACHED PAGES ___ THROUGH ___)

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2000

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 21.0 | 57.0 | 57.0 | 57.0 | 30.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 |
| SLCA - IP | ** Note 1 ** | 1.7 | 1.7 | 1.5 | 7.4 | 7.5 | 7.8 | 8.9 | 8.3 | 7.3 | 1.5 | 1.5 | 1.7 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **606.1** | **606.1** | **611.3** | **617.2** | **638.3** | **674.6** | **675.7** | **675.1** | **647.1** | **605.9** | **605.9** | **606.1** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| Cyprus Contingent | | 1.8 | 2.1 | 2.1 | 2.3 | 2.2 | 2.1 | 1.6 | 1.6 | 1.6 | 1.8 | 2.1 | 2.1 |
| Morenci Water & Electric Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Total Other Firm Loads | | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 |
| Total Other Contingent Loads | | 19.3 | 19.6 | 19.6 | 19.8 | 19.7 | 19.6 | 19.1 | 19.1 | 19.1 | 19.3 | 19.6 | 19.6 |
| **Power Sales Resources** | | **247.3** | **247.6** | **247.6** | **247.8** | **247.7** | **247.6** | **247.1** | **247.1** | **247.1** | **247.3** | **247.6** | **247.6** |
| **Adjusted Capacity** | | **358.8** | **358.5** | **363.7** | **369.4** | **390.6** | **427.0** | **428.6** | **428.0** | **400.0** | **358.6** | **358.3** | **358.5** |
| Power Sales Losses 2.97% | | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 |
| Power Sales Reserves 12.0% | | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 |
| **Net Class A Capacity** | | **324.7** | **324.3** | **329.6** | **335.3** | **356.5** | **392.9** | **394.4** | **393.9** | **365.9** | **324.5** | **324.2** | **324.4** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 116.2 | 116.1 | 118.0 | 120.0 | 127.6 | 140.7 | 141.2 | 141.0 | 131.0 | 116.2 | 116.1 | 116.1 |
| Mohave Reserves @ 12% | | 12.1 | 12.1 | 12.3 | 12.5 | 13.3 | 14.7 | 14.7 | 14.7 | 13.7 | 12.1 | 12.1 | 12.1 |
| Mohave Losses @ 2.97% | | 3.0 | 3.0 | 3.0 | 3.1 | 3.3 | 3.6 | 3.6 | 3.6 | 3.4 | 3.0 | 3.0 | 3.0 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **101.1** | **101.0** | **102.6** | **104.4** | **111.0** | **122.3** | **122.8** | **122.7** | **113.9** | **101.0** | **101.0** | **101.0** |
| Mohave Electric 1999 PRS NC Peak | | 62.8 | 54.6 | 53.3 | 65.7 | 79.1 | 113.5 | 138.2 | 139.2 | 117.4 | 73.2 | 52.4 | 67.7 |
| **All Requirements (AR) Capacity** | | **208.5** | **208.2** | **211.6** | **215.3** | **228.8** | **252.2** | **253.2** | **252.9** | **234.9** | **208.3** | **208.1** | **208.3** |
| AR Losses 2.97% Based on ARCP | | 4.9 | 4.8 | 4.2 | 4.2 | 4.9 | 5.6 | 6.3 | 6.1 | 5.6 | 4.9 | 4.4 | 5.0 |
| AR Reserves 12.0% Based on ARCP | | 19.8 | 19.3 | 17.1 | 16.9 | 19.7 | 22.8 | 25.5 | 24.7 | 22.8 | 19.7 | 17.7 | 20.2 |
| **AR Losses & Reserves Based on ARCP** | | **24.7** | **24.0** | **21.4** | **21.0** | **24.5** | **28.5** | **31.8** | **30.8** | **28.5** | **24.5** | **22.1** | **25.2** |
| **Net All Requirements Capacity** | | **183.8** | **184.2** | **190.2** | **194.2** | **204.3** | **223.8** | **221.4** | **222.1** | **206.4** | **183.8** | **186.0** | **183.0** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 5.5 | 5.6 | 5.0 | 5.1 | 5.3 | 6.3 | 7.9 | 8.3 | 7.1 | 5.1 | 5.7 | 6.4 |
| Duncan Valley Electric Cooperative | | 3.6 | 3.6 | 3.2 | 3.2 | 3.7 | 4.5 | 4.7 | 4.3 | 4.1 | 3.4 | 3.5 | 3.8 |
| Graham County Electric Cooperative | | 14.9 | 14.9 | 14.0 | 14.9 | 19.9 | 23.9 | 30.4 | 25.2 | 23.0 | 19.9 | 15.1 | 15.8 |
| Sulphur Springs Valley Electric | | 85.0 | 83.5 | 73.9 | 70.8 | 83.0 | 93.5 | 98.5 | 95.3 | 90.7 | 76.3 | 76.9 | 86.2 |
| Trico Electric Cooperative | | 55.9 | 53.0 | 46.6 | 46.5 | 52.0 | 62.0 | 71.0 | 72.7 | 65.3 | 59.2 | 46.6 | 56.5 |
| **AR Coincidental Peak (ARCP)** | | **164.9** | **160.6** | **142.8** | **140.5** | **163.8** | **190.2** | **212.5** | **205.8** | **190.1** | **163.8** | **147.7** | **168.6** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2001

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 35.0 | 35.0 | 5.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 66.0 | 66.0 | 66.0 | 66.0 | 66.0 | 90.0 | 90.0 | 90.0 | 90.0 | 90.0 | 90.0 | 90.0 |
| SLCA - IP | ** Note 1 ** | 1.7 | 1.7 | 1.5 | 7.4 | 7.5 | 7.8 | 8.9 | 8.3 | 7.3 | 1.5 | 1.5 | 1.7 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **606.1** | **606.1** | **611.3** | **617.2** | **617.3** | **641.6** | **677.7** | **677.1** | **646.1** | **629.9** | **629.9** | **630.1** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| Cyprus Contingent | | 1.8 | 2.1 | 2.1 | 2.3 | 2.2 | 2.1 | 1.6 | 1.6 | 1.6 | 1.8 | 2.1 | 2.1 |
| Morenci Water & Electric Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Total Other Firm Loads | | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 | 228.0 |
| Total Other Contingent Loads | | 19.3 | 19.6 | 19.6 | 19.8 | 19.7 | 19.6 | 19.1 | 19.1 | 19.1 | 19.3 | 19.6 | 19.6 |
| **Power Sales Resources** | | **247.3** | **247.6** | **247.6** | **247.8** | **247.7** | **247.6** | **247.1** | **247.1** | **247.1** | **247.3** | **247.6** | **247.6** |
| **Adjusted Capacity** | | **358.8** | **358.5** | **363.7** | **369.4** | **369.6** | **394.0** | **430.6** | **430.0** | **399.0** | **382.6** | **382.3** | **382.5** |
| Power Sales Losses 2.97% | | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 | 6.8 |
| Power Sales Reserves 12.0% | | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 | 27.4 |
| **Net Class A Capacity** | | **324.7** | **324.3** | **329.6** | **335.3** | **335.5** | **359.9** | **396.4** | **395.9** | **364.9** | **348.5** | **348.2** | **348.4** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 116.2 | 116.1 | 118.0 | 120.0 | 120.1 | 128.8 | 141.9 | 141.7 | 130.6 | 124.8 | 124.7 | 124.7 |
| Mohave Reserves @ 12% | | 12.1 | 12.1 | 12.3 | 12.5 | 12.5 | 13.4 | 14.8 | 14.8 | 13.6 | 13.0 | 13.0 | 13.0 |
| Mohave Losses @ 2.97% | | 3.0 | 3.0 | 3.0 | 3.1 | 3.1 | 3.3 | 3.7 | 3.7 | 3.4 | 3.2 | 3.2 | 3.2 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **101.1** | **101.0** | **102.6** | **104.4** | **104.5** | **112.1** | **123.4** | **123.3** | **113.6** | **108.5** | **108.4** | **108.5** |
| Mohave Electric 1999 PRS NC Peak | | 62.9 | 53.3 | 51.3 | 63.6 | 80.3 | 115.0 | 141.1 | 142.5 | 118.6 | 73.1 | 51.0 | 67.6 |
| **All Requirements (AR) Capacity** | | **208.5** | **208.2** | **211.6** | **215.3** | **215.4** | **231.1** | **254.5** | **254.2** | **234.2** | **223.7** | **223.5** | **223.7** |
| AR Losses 2.97% Based on ARCP | | 5.1 | 5.0 | 4.4 | 4.3 | 5.1 | 5.9 | 6.5 | 6.3 | 5.8 | 5.0 | 4.6 | 5.2 |
| AR Reserves 12.0% Based on ARCP | | 20.5 | 20.1 | 17.8 | 17.5 | 20.5 | 23.7 | 26.3 | 25.5 | 23.6 | 20.4 | 18.6 | 21.1 |
| **AR Losses & Reserves Based on ARCP** | | **25.6** | **25.1** | **22.2** | **21.8** | **25.5** | **29.6** | **32.8** | **31.8** | **29.4** | **25.4** | **23.2** | **26.3** |
| **Net All Requirements Capacity** | | **182.9** | **183.1** | **189.4** | **193.5** | **189.8** | **201.5** | **221.7** | **222.4** | **204.9** | **198.3** | **200.4** | **197.3** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 5.7 | 5.7 | 5.0 | 5.2 | 5.4 | 6.3 | 7.8 | 8.3 | 7.2 | 5.3 | 5.8 | 6.4 |
| Duncan Valley Electric Cooperative | | 3.7 | 4.2 | 3.3 | 3.2 | 3.8 | 4.6 | 4.7 | 4.3 | 4.1 | 3.5 | 3.7 | 3.9 |
| Graham County Electric Cooperative | | 15.1 | 15.4 | 14.4 | 15.2 | 20.2 | 24.2 | 30.7 | 25.5 | 23.2 | 20.1 | 15.7 | 16.3 |
| Sulphur Springs Valley Electric | | 86.8 | 85.3 | 75.5 | 72.4 | 85.0 | 95.9 | 101.2 | 97.6 | 92.7 | 77.9 | 78.6 | 88.2 |
| Trico Electric Cooperative | | 59.5 | 57.1 | 50.1 | 49.7 | 56.1 | 66.5 | 74.9 | 76.5 | 69.1 | 63.2 | 51.0 | 61.0 |
| **AR Coincidental Peak (ARCP)** | | **170.8** | **167.7** | **148.3** | **145.7** | **170.5** | **197.5** | **219.4** | **212.3** | **196.4** | **169.9** | **154.8** | **175.9** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2002

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 15.0 | 15.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 90.0 | 90.0 | 90.0 | 90.0 | 90.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| SLCA - IP | ** Note 1 ** | 1.7 | 1.7 | 1.5 | 7.4 | 7.5 | 7.8 | 8.9 | 8.3 | 7.3 | 1.5 | 1.5 | 1.7 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | 630.1 | 630.1 | 635.3 | 641.2 | 641.3 | 564.6 | 580.7 | 580.1 | 564.1 | 552.9 | 552.9 | 553.1 |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | 240.5 | 240.5 | 240.5 | 240.5 | 240.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 |
| **Adjusted Capacity** | | 389.6 | 389.6 | 394.8 | 400.7 | 400.8 | 424.1 | 440.2 | 439.6 | 423.6 | 412.4 | 412.4 | 412.6 |
| Power Sales Losses 2.97% | | 6.6 | 6.6 | 6.6 | 6.6 | 6.6 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 |
| Power Sales Reserves 12.0% | | 26.8 | 26.8 | 26.8 | 26.8 | 26.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 |
| **Net Class A Capacity** | | 356.2 | 356.2 | 361.5 | 367.4 | 367.4 | 405.7 | 421.7 | 421.2 | 405.2 | 394.0 | 394.0 | 394.2 |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 127.5 | 127.5 | 129.4 | 131.5 | 131.5 | 145.2 | 151.0 | 150.8 | 145.1 | 141.1 | 141.1 | 141.1 |
| Mohave Reserves @ 12% | | 13.3 | 13.3 | 13.5 | 13.7 | 13.7 | 15.2 | 15.8 | 15.7 | 15.1 | 14.7 | 14.7 | 14.7 |
| Mohave Losses @ 2.97% | | 3.3 | 3.3 | 3.3 | 3.4 | 3.4 | 3.8 | 3.9 | 3.9 | 3.7 | 3.6 | 3.6 | 3.6 |
| **Partial Requirements Allocated Capacity (Mohave)** | | 110.9 | 110.9 | 112.6 | 114.4 | 114.4 | 126.3 | 131.3 | 131.2 | 126.2 | 122.7 | 122.7 | 122.7 |
| Mohave Electric 1999 PRS NC Peak | | 63.7 | 52.8 | 50.1 | 62.4 | 82.0 | 116.9 | 144.3 | 146.0 | 120.3 | 73.6 | 50.5 | 68.1 |
| **All Requirements (AR) Capacity** | | 228.7 | 228.7 | 232.1 | 235.8 | 235.9 | 260.5 | 270.8 | 270.4 | 260.1 | 253.0 | 253.0 | 253.1 |
| AR Losses 2.97% Based on ARCP | | 5.3 | 5.2 | 4.6 | 4.5 | 5.3 | 6.1 | 6.7 | 6.5 | 6.0 | 5.2 | 4.8 | 5.4 |
| AR Reserves 12.0% Based on ARCP | | 21.2 | 20.9 | 18.5 | 18.1 | 21.3 | 24.7 | 27.3 | 26.3 | 24.3 | 21.1 | 19.4 | 22.0 |
| **AR Losses & Reserves Based on ARCP** | | 26.5 | 26.0 | 23.0 | 22.6 | 26.6 | 30.8 | 34.0 | 32.8 | 30.3 | 26.3 | 24.1 | 27.4 |
| **Net All Requirements Capacity** | | 202.2 | 202.6 | 209.0 | 213.2 | 209.3 | 229.7 | 236.8 | 237.6 | 229.8 | 226.6 | 228.8 | 225.7 |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 5.8 | 5.8 | 5.2 | 5.3 | 5.5 | 6.4 | 8.0 | 8.5 | 7.4 | 5.4 | 6.0 | 6.6 |
| Duncan Valley Electric Cooperative | | 3.8 | 4.1 | 3.4 | 3.3 | 3.9 | 4.7 | 4.8 | 4.4 | 4.1 | 3.6 | 3.8 | 4.0 |
| Graham County Electric Cooperative | | 15.3 | 15.9 | 14.7 | 15.5 | 20.5 | 24.8 | 31.1 | 25.9 | 23.5 | 20.3 | 16.2 | 16.9 |
| Sulphur Springs Valley Electric | | 88.8 | 87.1 | 77.1 | 74.0 | 87.0 | 98.4 | 103.9 | 99.9 | 94.7 | 79.5 | 80.3 | 90.2 |
| Trico Electric Cooperative | | 63.3 | 61.0 | 53.6 | 53.2 | 60.4 | 71.3 | 79.4 | 80.6 | 72.9 | 67.1 | 55.0 | 65.4 |
| **AR Coincidental Peak (ARCP)** | | 176.9 | 173.9 | 153.9 | 151.2 | 177.4 | 205.6 | 227.2 | 219.3 | 202.6 | 175.9 | 161.3 | 183.1 |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2003

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 25.0 | 25.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| SLCA - IP | ** Note 1 ** | 1.7 | 1.7 | 1.5 | 7.4 | 7.5 | 7.8 | 8.9 | 8.3 | 7.3 | 1.5 | 1.5 | 1.7 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **553.1** | **553.1** | **558.3** | **564.2** | **564.3** | **564.6** | **590.7** | **590.1** | **564.1** | **552.9** | **552.9** | **553.1** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** |
| **Adjusted Capacity** | | **412.6** | **412.6** | **417.8** | **423.7** | **423.8** | **424.1** | **450.2** | **449.6** | **423.6** | **412.4** | **412.4** | **412.6** |
| Power Sales Losses 2.97% | | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 |
| Power Sales Reserves 12.0% | | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 |
| **Net Class A Capacity** | | **394.2** | **394.2** | **399.4** | **405.3** | **405.4** | **405.7** | **431.7** | **431.2** | **405.2** | **394.0** | **394.0** | **394.2** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 141.1 | 141.1 | 143.0 | 145.1 | 145.1 | 145.2 | 154.6 | 154.4 | 145.1 | 141.1 | 141.1 | 141.1 |
| Mohave Reserves @ 12% | | 14.7 | 14.7 | 14.9 | 15.1 | 15.1 | 15.2 | 16.1 | 16.1 | 15.1 | 14.7 | 14.7 | 14.7 |
| Mohave Losses @ 2.97% | | 3.6 | 3.6 | 3.7 | 3.7 | 3.7 | 3.8 | 4.0 | 4.0 | 3.7 | 3.6 | 3.6 | 3.6 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **122.8** | **122.7** | **124.4** | **126.2** | **126.2** | **126.3** | **134.4** | **134.3** | **126.2** | **122.7** | **122.7** | **122.7** |
| Mohave Electric 1999 PRS NC Peak | | 64.4 | 52.6 | 49.3 | 61.6 | 83.5 | 118.7 | 147.2 | 149.2 | 122.0 | 74.3 | 50.2 | 68.8 |
| **All Requirements (AR) Capacity** | | **253.1** | **253.0** | **256.4** | **260.2** | **260.3** | **260.5** | **277.2** | **276.9** | **260.1** | **253.0** | **253.0** | **253.1** |
| AR Losses 2.97% Based on ARCP | | 5.4 | 5.3 | 4.7 | 4.6 | 5.5 | 6.3 | 7.0 | 6.7 | 6.2 | 5.4 | 5.0 | 5.6 |
| AR Reserves 12.0% Based on ARCP | | 22.0 | 21.6 | 19.1 | 18.8 | 22.1 | 25.6 | 28.2 | 27.2 | 25.1 | 21.8 | 20.1 | 22.8 |
| **AR Losses & Reserves Based on ARCP** | | **27.4** | **26.9** | **23.9** | **23.4** | **27.5** | **32.0** | **35.2** | **33.9** | **31.3** | **27.2** | **25.1** | **28.5** |
| **Net All Requirements Capacity** | | **225.7** | **226.1** | **232.6** | **236.8** | **232.7** | **228.5** | **242.0** | **242.9** | **228.8** | **225.7** | **227.9** | **224.6** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 5.9 | 5.9 | 5.2 | 5.4 | 5.6 | 6.5 | 8.0 | 8.5 | 7.5 | 5.5 | 6.1 | 6.7 |
| Duncan Valley Electric Cooperative | | 3.8 | 4.1 | 3.4 | 3.3 | 4.0 | 4.8 | 4.9 | 4.4 | 4.1 | 3.7 | 3.9 | 4.1 |
| Graham County Electric Cooperative | | 15.4 | 16.3 | 15.0 | 15.8 | 20.9 | 25.4 | 31.5 | 26.2 | 23.8 | 20.6 | 16.7 | 17.4 |
| Sulphur Springs Valley Electric | | 90.6 | 88.8 | 78.7 | 75.5 | 89.1 | 100.8 | 106.6 | 102.2 | 96.7 | 81.2 | 82.1 | 92.3 |
| Trico Electric Cooperative | | 67.3 | 65.0 | 57.0 | 56.5 | 64.4 | 76.0 | 84.1 | 85.2 | 76.9 | 71.0 | 58.7 | 69.8 |
| **AR Coincidental Peak (ARCP)** | | **183.1** | **180.0** | **159.5** | **156.5** | **184.0** | **213.5** | **235.0** | **226.5** | **209.1** | **181.9** | **167.5** | **190.2** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2004

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| SLCA - IP | ** Note 1 ** | 1.7 | 1.7 | 1.5 | 7.4 | 7.5 | 7.8 | 8.9 | 8.3 | 7.3 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **553.1** | **553.1** | **558.3** | **564.2** | **564.3** | **564.6** | **565.7** | **565.1** | **564.1** | **552.8** | **552.8** | **553.0** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** |
| **Adjusted Capacity** | | **412.6** | **412.6** | **417.8** | **423.7** | **423.8** | **424.1** | **425.2** | **424.6** | **423.6** | **412.3** | **412.3** | **412.5** |
| Power Sales Losses 2.97% | | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 |
| Power Sales Reserves 12.0% | | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 |
| **Net Class A Capacity** | | **394.2** | **394.2** | **399.4** | **405.3** | **405.4** | **405.7** | **406.7** | **406.2** | **405.2** | **393.9** | **393.9** | **394.1** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 141.1 | 141.1 | 143.0 | 145.1 | 145.1 | 145.2 | 145.6 | 145.4 | 145.1 | 141.0 | 141.0 | 141.1 |
| Mohave Reserves @ 12% | | 14.7 | 14.7 | 14.9 | 15.1 | 15.1 | 15.2 | 15.2 | 15.2 | 15.1 | 14.7 | 14.7 | 14.7 |
| Mohave Losses @ 2.97% | | 3.6 | 3.6 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.8 | 3.7 | 3.6 | 3.6 | 3.6 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **122.8** | **122.7** | **124.4** | **126.2** | **126.2** | **126.3** | **126.7** | **126.5** | **126.2** | **122.7** | **122.7** | **122.7** |
| Mohave Electric 1999 PRS NC Peak | | 65.3 | 52.6 | 48.8 | 61.0 | 85.0 | 120.5 | 149.8 | 152.2 | 123.7 | 75.0 | 50.1 | 69.5 |
| **All Requirements (AR) Capacity** | | **253.1** | **253.0** | **256.4** | **260.2** | **260.3** | **260.5** | **261.1** | **260.8** | **260.1** | **252.9** | **252.9** | **253.0** |
| AR Losses 2.97% Based on ARCP | | 5.6 | 5.5 | 4.9 | 4.8 | 5.7 | 6.6 | 7.2 | 6.9 | 6.4 | 5.6 | 5.2 | 5.9 |
| AR Reserves 12.0% Based on ARCP | | 22.7 | 22.4 | 19.8 | 19.4 | 22.8 | 26.5 | 29.2 | 28.1 | 25.9 | 22.5 | 20.8 | 23.7 |
| **AR Losses & Reserves Based on ARCP** | | **28.4** | **27.9** | **24.7** | **24.2** | **28.5** | **33.1** | **36.4** | **35.0** | **32.3** | **28.1** | **26.0** | **29.5** |
| **Net All Requirements Capacity** | | **224.7** | **225.2** | **231.7** | **236.0** | **231.8** | **227.4** | **224.7** | **225.8** | **227.9** | **224.8** | **226.9** | **223.5** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.0 | 6.0 | 5.3 | 5.5 | 5.7 | 6.6 | 8.0 | 8.6 | 7.6 | 5.6 | 6.2 | 6.8 |
| Duncan Valley Electric Cooperative | | 3.9 | 4.1 | 3.5 | 3.4 | 4.1 | 4.9 | 4.9 | 4.5 | 4.1 | 3.7 | 4.0 | 4.1 |
| Graham County Electric Cooperative | | 15.6 | 16.7 | 15.4 | 16.0 | 21.0 | 25.7 | 31.8 | 26.5 | 24.1 | 20.8 | 17.4 | 17.8 |
| Sulphur Springs Valley Electric | | 92.5 | 90.6 | 80.3 | 77.1 | 91.2 | 103.4 | 109.4 | 104.6 | 98.7 | 82.9 | 83.9 | 94.4 |
| Trico Electric Cooperative | | 71.4 | 69.0 | 60.5 | 59.8 | 68.3 | 80.6 | 88.9 | 89.8 | 81.0 | 74.8 | 62.1 | 74.0 |
| **AR Coincidental Peak (ARCP)** | | **189.5** | **186.3** | **165.0** | **161.8** | **190.4** | **221.2** | **243.1** | **233.9** | **215.6** | **187.9** | **173.6** | **197.2** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2005

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **553.0** | **553.0** | **558.2** | **563.7** | **563.8** | **564.1** | **565.0** | **564.6** | **563.6** | **552.8** | **552.8** | **553.0** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** |
| **Adjusted Capacity** | | **412.5** | **412.5** | **417.7** | **423.2** | **423.3** | **423.6** | **424.5** | **424.1** | **423.1** | **412.3** | **412.3** | **412.5** |
| Power Sales Losses 2.97% | | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 |
| Power Sales Reserves 12.0% | | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 |
| **Class A Capacity** | | **394.1** | **394.0** | **399.3** | **404.8** | **404.9** | **405.2** | **406.1** | **405.7** | **404.7** | **393.9** | **393.9** | **394.1** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 141.1 | 141.1 | 143.0 | 144.9 | 144.9 | 145.1 | 145.4 | 145.2 | 144.9 | 141.0 | 141.0 | 141.1 |
| Mohave Reserves @ 12% | | 14.7 | 14.7 | 14.9 | 15.1 | 15.1 | 15.1 | 15.2 | 15.2 | 15.1 | 14.7 | 14.7 | 14.7 |
| Mohave Losses @ 2.97% | | 3.6 | 3.6 | 3.7 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.7 | 3.6 | 3.6 | 3.6 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **122.7** | **122.7** | **124.3** | **126.1** | **126.1** | **126.2** | **126.5** | **126.3** | **126.0** | **122.7** | **122.7** | **122.7** |
| Mohave Electric 1999 PRS NC Peak | | 66.7 | 53.2 | 49.0 | 61.2 | 86.9 | 122.6 | 152.8 | 155.4 | 125.8 | 76.4 | 50.7 | 70.8 |
| **All Requirements (AR) Capacity** | | **253.0** | **253.0** | **256.4** | **259.9** | **259.9** | **260.1** | **260.7** | **260.4** | **259.8** | **252.9** | **252.9** | **253.0** |
| AR Losses 2.97% Based on ARCP | | 5.8 | 5.7 | 5.1 | 5.0 | 5.9 | 6.8 | 7.5 | 7.2 | 6.6 | 5.8 | 5.3 | 6.1 |
| AR Reserves 12.0% Based on ARCP | | 23.5 | 23.1 | 20.5 | 20.1 | 23.6 | 27.5 | 30.2 | 29.0 | 26.7 | 23.3 | 21.6 | 24.5 |
| **AR Losses & Reserves Based on ARCP** | | **29.4** | **28.8** | **25.6** | **25.0** | **29.5** | **34.3** | **37.7** | **36.2** | **33.3** | **29.1** | **26.9** | **30.6** |
| **Net All Requirements Capacity** | | **223.7** | **224.1** | **230.8** | **234.9** | **230.4** | **225.8** | **223.1** | **224.2** | **226.5** | **223.8** | **226.0** | **222.4** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.2 | 6.1 | 5.5 | 5.7 | 5.8 | 6.7 | 8.1 | 8.8 | 7.8 | 5.8 | 6.4 | 6.9 |
| Duncan Valley Electric Cooperative | | 4.0 | 4.0 | 3.6 | 3.4 | 4.2 | 4.9 | 5.0 | 4.5 | 4.2 | 3.8 | 4.1 | 4.2 |
| Graham County Electric Cooperative | | 15.8 | 17.0 | 15.6 | 16.2 | 21.3 | 26.0 | 32.2 | 26.8 | 24.4 | 21.1 | 17.7 | 18.2 |
| Sulphur Springs Valley Electric | | 94.6 | 92.5 | 82.1 | 78.7 | 93.5 | 106.0 | 112.4 | 107.1 | 100.9 | 84.7 | 85.8 | 96.6 |
| Trico Electric Cooperative | | 75.5 | 73.0 | 64.0 | 63.1 | 72.2 | 85.2 | 93.8 | 94.6 | 85.2 | 78.8 | 65.8 | 78.4 |
| **AR Coincidental Peak (ARCP)** | | **198.1** | **192.6** | **170.7** | **167.2** | **197.0** | **229.0** | **251.6** | **241.8** | **222.4** | **194.1** | **179.8** | **204.2** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2006

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | 553.0 | 553.0 | 558.2 | 563.7 | 563.8 | 564.1 | 565.0 | 564.6 | 563.6 | 552.8 | 552.8 | 553.0 |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 |
| **Adjusted Capacity** | | 412.5 | 412.5 | 417.7 | 423.2 | 423.3 | 423.6 | 424.5 | 424.1 | 423.1 | 412.3 | 412.3 | 412.5 |
| Power Sales Losses 2.97% | | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 |
| Power Sales Reserves 12.0% | | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 |
| **Net Class A Capacity** | | 394.1 | 394.0 | 399.3 | 404.8 | 404.9 | 405.2 | 406.1 | 405.7 | 404.7 | 393.9 | 393.9 | 394.1 |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 141.1 | 141.1 | 143.0 | 144.9 | 144.9 | 145.1 | 145.4 | 145.2 | 144.9 | 141.0 | 141.0 | 141.1 |
| Mohave Reserves @ 12% | | 14.7 | 14.7 | 14.9 | 15.1 | 15.1 | 15.1 | 15.2 | 15.2 | 15.1 | 14.7 | 14.7 | 14.7 |
| Mohave Losses @ 2.97% | | 3.6 | 3.6 | 3.7 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.7 | 3.6 | 3.6 | 3.6 |
| **Partial Requirements Allocated Capacity (Mohave)** | | 122.7 | 122.7 | 124.3 | 126.1 | 126.1 | 126.2 | 126.5 | 126.3 | 126.0 | 122.7 | 122.7 | 122.7 |
| Mohave Electric 1999 PRS NC Peak | | 68.1 | 54.0 | 49.4 | 61.6 | 88.8 | 124.7 | 155.5 | 158.4 | 127.9 | 77.8 | 51.5 | 72.1 |
| **All Requirements (AR) Capacity** | | 253.0 | 253.0 | 256.4 | 259.9 | 259.9 | 260.1 | 260.7 | 260.4 | 259.8 | 252.9 | 252.9 | 253.0 |
| AR Losses 2.97% Based on ARCP | | 6.0 | 5.9 | 5.2 | 5.1 | 6.1 | 7.0 | 7.7 | 7.4 | 6.8 | 5.9 | 5.5 | 6.3 |
| AR Reserves 12.0% Based on ARCP | | 24.3 | 23.9 | 21.2 | 20.7 | 24.5 | 28.4 | 31.2 | 30.0 | 27.5 | 24.0 | 22.3 | 25.4 |
| **AR Losses & Reserves Based on ARCP** | | 30.3 | 29.8 | 26.4 | 25.9 | 30.5 | 35.5 | 38.9 | 37.4 | 34.3 | 30.0 | 27.8 | 31.6 |
| **Net All Requirements Capacity** | | 222.7 | 223.2 | 229.9 | 234.0 | 229.4 | 224.6 | 221.8 | 223.0 | 225.5 | 222.9 | 225.1 | 221.4 |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.3 | 6.2 | 5.5 | 5.8 | 5.9 | 6.8 | 8.2 | 8.9 | 7.9 | 5.9 | 6.5 | 7.0 |
| Duncan Valley Electric Cooperative | | 4.0 | 4.1 | 3.6 | 3.5 | 4.2 | 5.0 | 5.0 | 4.5 | 4.2 | 3.7 | 3.9 | 4.2 |
| Graham County Electric Cooperative | | 16.0 | 17.3 | 15.9 | 16.5 | 21.6 | 26.5 | 32.6 | 27.1 | 24.7 | 21.3 | 18.1 | 18.6 |
| Sulphur Springs Valley Electric | | 96.6 | 94.4 | 83.9 | 80.4 | 95.9 | 108.8 | 115.4 | 109.6 | 103.1 | 86.6 | 87.8 | 98.8 |
| Trico Electric Cooperative | | 79.8 | 77.0 | 67.6 | 66.6 | 76.3 | 89.9 | 98.8 | 99.5 | 89.5 | 82.8 | 69.4 | 82.7 |
| **AR Coincidental Peak (ARCP)** | | 202.7 | 199.0 | 176.5 | 172.7 | 203.8 | 237.0 | 260.1 | 249.7 | 229.4 | 200.3 | 185.7 | 211.3 |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2007

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **553.0** | **553.0** | **558.2** | **563.7** | **563.8** | **564.1** | **565.0** | **564.6** | **563.6** | **552.8** | **552.8** | **553.0** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** | **140.5** |
| **Adjusted Capacity** | | **412.5** | **412.5** | **417.7** | **423.2** | **423.3** | **423.6** | **424.5** | **424.1** | **423.1** | **412.3** | **412.3** | **412.5** |
| Power Sales Losses 2.97% | | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 |
| Power Sales Reserves 12.0% | | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 |
| **Net Class A Capacity** | | **394.1** | **394.0** | **399.3** | **404.8** | **404.9** | **405.2** | **406.1** | **405.7** | **404.7** | **393.9** | **393.9** | **394.1** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 141.1 | 141.1 | 143.0 | 144.9 | 144.9 | 145.1 | 145.4 | 145.2 | 144.9 | 141.0 | 141.0 | 141.1 |
| Mohave Reserves @ 12% | | 14.7 | 14.7 | 14.9 | 15.1 | 15.1 | 15.1 | 15.2 | 15.2 | 15.1 | 14.7 | 14.7 | 14.7 |
| Mohave Losses @ 2.97% | | 3.6 | 3.6 | 3.7 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.7 | 3.6 | 3.6 | 3.6 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **122.7** | **122.7** | **124.3** | **126.1** | **126.1** | **126.2** | **126.5** | **126.3** | **126.0** | **122.7** | **122.7** | **122.7** |
| Mohave Electric 1999 PRS NC Peak | | 70.5 | 55.9 | 51.0 | 63.1 | 91.6 | 127.7 | 159.2 | 162.3 | 131.0 | 80.2 | 53.4 | 74.4 |
| **All Requirements (AR) Capacity** | | **253.0** | **253.0** | **256.4** | **259.9** | **259.9** | **260.1** | **260.7** | **260.4** | **259.8** | **252.9** | **252.9** | **253.0** |
| AR Losses 2.97% Based on ARCP | | 6.2 | 6.1 | 5.4 | 5.3 | 6.2 | 7.3 | 8.0 | 7.7 | 7.0 | 6.1 | 5.7 | 6.5 |
| AR Reserves 12.0% Based on ARCP | | 25.1 | 24.7 | 21.9 | 21.4 | 25.2 | 29.3 | 32.2 | 30.9 | 28.4 | 24.8 | 23.0 | 26.2 |
| **AR Losses & Reserves Based on ARCP** | | **31.4** | **30.8** | **27.3** | **26.7** | **31.5** | **36.6** | **40.2** | **38.6** | **35.4** | **30.9** | **28.7** | **32.7** |
| **Net All Requirements Capacity** | | **221.7** | **222.2** | **229.1** | **233.2** | **228.4** | **223.5** | **220.5** | **221.9** | **224.4** | **221.9** | **224.2** | **220.3** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.4 | 6.3 | 5.6 | 5.8 | 6.0 | 6.9 | 8.3 | 9.0 | 8.0 | 6.0 | 6.6 | 7.1 |
| Duncan Valley Electric Cooperative | | 4.1 | 4.1 | 3.6 | 3.5 | 4.0 | 4.7 | 4.9 | 4.5 | 4.3 | 3.8 | 4.0 | 4.2 |
| Graham County Electric Cooperative | | 16.2 | 17.6 | 16.2 | 16.8 | 21.9 | 26.8 | 33.0 | 27.4 | 25.0 | 21.6 | 18.5 | 19.0 |
| Sulphur Springs Valley Electric | | 98.8 | 96.4 | 85.8 | 82.1 | 98.3 | 111.5 | 118.4 | 112.2 | 105.3 | 88.5 | 89.8 | 101.0 |
| Trico Electric Cooperative | | 84.0 | 81.1 | 71.2 | 70.1 | 80.3 | 94.6 | 103.9 | 104.5 | 93.8 | 86.9 | 72.9 | 86.9 |
| **AR Coincidental Peak (ARCP)** | | **209.4** | **205.5** | **182.3** | **178.3** | **210.4** | **244.6** | **268.5** | **257.6** | **236.4** | **206.7** | **191.7** | **218.3** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2008

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | 553.0 | 553.0 | 558.2 | 563.7 | 563.8 | 564.1 | 565.0 | 564.6 | 563.6 | 552.8 | 552.8 | 553.0 |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 | 140.5 |
| **Adjusted Capacity** | | 412.5 | 412.5 | 417.7 | 423.2 | 423.3 | 423.6 | 424.5 | 424.1 | 423.1 | 412.3 | 412.3 | 412.5 |
| Power Sales Losses 2.97% | | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 |
| Power Sales Reserves 12.0% | | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 |
| **Net Class A Capacity** | | 394.1 | 394.0 | 399.3 | 404.8 | 404.9 | 405.2 | 406.1 | 405.7 | 404.7 | 393.9 | 393.9 | 394.1 |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 141.1 | 141.1 | 143.0 | 144.9 | 144.9 | 145.1 | 145.4 | 145.2 | 144.9 | 141.0 | 141.0 | 141.1 |
| Mohave Reserves @ 12% | | 14.7 | 14.7 | 14.9 | 15.1 | 15.1 | 15.1 | 15.2 | 15.2 | 15.1 | 14.7 | 14.7 | 14.7 |
| Mohave Losses @ 2.97% | | 3.6 | 3.6 | 3.7 | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.7 | 3.6 | 3.6 | 3.6 |
| **Partial Requirements Allocated Capacity (Mohave)** | | 122.7 | 122.7 | 124.3 | 126.1 | 126.1 | 126.2 | 126.5 | 126.3 | 126.0 | 122.7 | 122.7 | 122.7 |
| Mohave Electric 1999 PRS NC Peak | | 73.5 | 58.4 | 53.2 | 65.4 | 95.0 | 131.2 | 163.3 | 166.6 | 134.7 | 83.3 | 55.9 | 77.4 |
| **All Requirements (AR) Capacity** | | 253.0 | 253.0 | 256.4 | 259.9 | 259.9 | 260.1 | 260.7 | 260.4 | 259.8 | 252.9 | 252.9 | 253.0 |
| AR Losses 2.97% Based on ARCP | | 6.4 | 6.3 | 5.6 | 5.5 | 6.5 | 7.5 | 8.2 | 7.9 | 7.2 | 6.3 | 5.9 | 6.7 |
| AR Reserves 12.0% Based on ARCP | | 25.9 | 25.4 | 22.6 | 22.1 | 26.1 | 30.3 | 33.3 | 31.9 | 29.2 | 25.6 | 23.7 | 27.0 |
| **AR Losses & Reserves Based on ARCP** | | 32.4 | 31.7 | 28.2 | 27.5 | 32.5 | 37.8 | 41.5 | 39.8 | 36.5 | 31.9 | 29.6 | 33.7 |
| **Net All Requirements Capacity** | | 220.6 | 221.2 | 228.2 | 232.4 | 227.4 | 222.3 | 219.2 | 220.6 | 223.4 | 221.0 | 223.3 | 219.3 |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.5 | 6.4 | 5.7 | 5.9 | 6.1 | 7.0 | 8.4 | 9.1 | 8.2 | 6.1 | 6.7 | 7.3 |
| Duncan Valley Electric Cooperative | | 4.1 | 4.1 | 3.7 | 3.6 | 4.1 | 4.8 | 5.0 | 4.6 | 4.3 | 3.8 | 4.0 | 4.3 |
| Graham County Electric Cooperative | | 16.4 | 17.9 | 16.4 | 17.1 | 22.2 | 27.2 | 33.4 | 27.8 | 25.3 | 21.8 | 18.8 | 19.3 |
| Sulphur Springs Valley Electric | | 100.9 | 98.4 | 87.7 | 83.8 | 100.7 | 114.3 | 121.5 | 114.7 | 107.5 | 90.4 | 91.9 | 103.4 |
| Trico Electric Cooperative | | 88.3 | 85.2 | 74.7 | 73.5 | 84.2 | 99.3 | 109.0 | 109.5 | 98.2 | 91.0 | 76.3 | 91.1 |
| **AR Coincidental Peak (ARCP)** | | 216.2 | 212.0 | 188.2 | 183.9 | 217.3 | 252.6 | 277.3 | 265.7 | 243.5 | 213.1 | 197.7 | 225.4 |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2009

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** |
| **Adjusted Capacity** | | **414.5** | **414.5** | **419.7** | **425.2** | **425.3** | **425.6** | **426.5** | **426.1** | **425.1** | **414.3** | **414.3** | **414.5** |
| Power Sales Losses 2.97% | | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 |
| Power Sales Reserves 12.0% | | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| **Class A Capacity** | | **398.3** | **398.3** | **403.6** | **409.1** | **409.1** | **409.4** | **410.4** | **409.9** | **408.9** | **398.1** | **398.2** | **398.3** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 142.6 | 142.6 | 144.5 | 146.4 | 146.5 | 146.6 | 146.9 | 146.7 | 146.4 | 142.5 | 142.5 | 142.6 |
| Mohave Reserves @ 12% | | 14.9 | 14.9 | 15.1 | 15.3 | 15.3 | 15.3 | 15.3 | 15.3 | 15.3 | 14.9 | 14.9 | 14.9 |
| Mohave Losses @ 2.97% | | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 3.7 | 3.7 | 3.7 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **124.0** | **124.0** | **125.7** | **127.4** | **127.4** | **127.5** | **127.8** | **127.6** | **127.3** | **124.0** | **124.0** | **124.0** |
| Mohave Electric 1999 PRS NC Peak | | 76.1 | 60.6 | 55.2 | 67.3 | 97.8 | 134.2 | 166.9 | 170.5 | 137.9 | 86.0 | 58.2 | 79.9 |
| **All Requirements (AR) Capacity** | | **255.7** | **255.7** | **259.1** | **262.6** | **262.6** | **262.8** | **263.5** | **263.2** | **262.5** | **255.6** | **255.6** | **255.7** |
| AR Losses 2.97% Based on ARCP | | 6.7 | 6.5 | 5.8 | 5.6 | 6.7 | 7.7 | 8.5 | 8.1 | 7.4 | 6.5 | 6.1 | 6.9 |
| AR Reserves 12.0% Based on ARCP | | 27.1 | 26.2 | 23.3 | 22.7 | 26.9 | 31.2 | 34.3 | 32.8 | 30.1 | 26.4 | 24.5 | 27.9 |
| **AR Losses & Reserves Based on ARCP** | | **33.8** | **32.7** | **29.0** | **28.4** | **33.6** | **39.0** | **42.8** | **41.0** | **37.5** | **32.9** | **30.5** | **34.8** |
| **Net All Requirements Capacity** | | **221.9** | **223.0** | **230.0** | **234.2** | **229.1** | **223.9** | **220.7** | **222.2** | **225.0** | **222.7** | **225.1** | **220.9** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.6 | 6.5 | 5.8 | 6.0 | 6.1 | 7.0 | 8.5 | 9.2 | 8.3 | 6.2 | 6.8 | 7.3 |
| Duncan Valley Electric Cooperative | | 4.2 | 4.2 | 3.7 | 3.6 | 4.2 | 4.8 | 5.1 | 4.6 | 4.4 | 3.9 | 4.1 | 4.4 |
| Graham County Electric Cooperative | | 19.3 | 18.2 | 16.7 | 17.3 | 22.5 | 27.5 | 33.8 | 28.1 | 25.6 | 22.1 | 19.1 | 19.7 |
| Sulphur Springs Valley Electric | | 103.2 | 100.5 | 89.6 | 85.6 | 103.1 | 116.9 | 124.3 | 117.3 | 109.8 | 92.4 | 94.0 | 105.7 |
| Trico Electric Cooperative | | 92.5 | 89.2 | 78.3 | 77.0 | 88.2 | 104.0 | 114.0 | 114.6 | 102.7 | 95.1 | 79.8 | 95.3 |
| **AR Coincidental Peak (ARCP)** | | **225.7** | **218.6** | **194.1** | **189.6** | **224.2** | **260.3** | **285.6** | **273.7** | **250.7** | **219.7** | **203.8** | **232.4** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2010

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 | 108.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** | **125.5** |
| **Adjusted Capacity** | | **414.5** | **414.5** | **419.7** | **425.2** | **425.3** | **425.6** | **426.5** | **426.1** | **425.1** | **414.3** | **414.3** | **414.5** |
| Power Sales Losses 2.97% | | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 |
| Power Sales Reserves 12.0% | | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 | 13.0 |
| **Net Class A Capacity** | | **398.3** | **398.3** | **403.6** | **409.1** | **409.1** | **409.4** | **410.4** | **409.9** | **408.9** | **398.1** | **398.2** | **398.3** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 142.6 | 142.6 | 144.5 | 146.4 | 146.5 | 146.6 | 146.9 | 146.7 | 146.4 | 142.5 | 142.5 | 142.6 |
| Mohave Reserves @ 12% | | 14.9 | 14.9 | 15.1 | 15.3 | 15.3 | 15.3 | 15.3 | 15.3 | 15.3 | 14.9 | 14.9 | 14.9 |
| Mohave Losses @ 2.97% | | 3.7 | 3.7 | 3.7 | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 3.7 | 3.7 | 3.7 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **124.0** | **124.0** | **125.7** | **127.4** | **127.4** | **127.5** | **127.8** | **127.6** | **127.3** | **124.0** | **124.0** | **124.0** |
| Mohave Electric 1999 PRS NC Peak | | 78.7 | 62.9 | 57.3 | 69.4 | 100.7 | 137.3 | 170.4 | 174.2 | 141.2 | 88.7 | 60.5 | 82.5 |
| **All Requirements (AR) Capacity** | | **255.7** | **255.7** | **259.1** | **262.6** | **262.6** | **262.8** | **263.5** | **263.2** | **262.5** | **255.6** | **255.6** | **255.7** |
| AR Losses 2.97% Based on ARCP | | 6.9 | 6.7 | 5.9 | 5.8 | 6.9 | 8.0 | 8.7 | 8.4 | 7.7 | 6.7 | 6.2 | 7.1 |
| AR Reserves 12.0% Based on ARCP | | 27.9 | 27.0 | 24.0 | 23.4 | 27.7 | 32.2 | 35.3 | 33.8 | 31.0 | 27.2 | 25.2 | 28.7 |
| **AR Losses & Reserves Based on ARCP** | | **34.8** | **33.7** | **29.9** | **29.2** | **34.6** | **40.2** | **44.0** | **42.2** | **38.6** | **33.9** | **31.4** | **35.9** |
| **Net All Requirements Capacity** | | **220.9** | **222.0** | **229.2** | **233.4** | **228.0** | **222.7** | **219.4** | **220.9** | **223.9** | **221.7** | **224.2** | **219.9** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.7 | 6.6 | 5.9 | 6.1 | 6.2 | 7.2 | 8.6 | 9.3 | 8.4 | 6.2 | 6.9 | 7.4 |
| Duncan Valley Electric Cooperative | | 4.2 | 4.2 | 3.8 | 3.7 | 4.2 | 4.9 | 5.1 | 4.7 | 4.5 | 4.0 | 4.2 | 4.4 |
| Graham County Electric Cooperative | | 19.6 | 18.5 | 16.9 | 17.6 | 22.8 | 27.9 | 34.2 | 28.4 | 25.9 | 22.4 | 19.4 | 20.0 |
| Sulphur Springs Valley Electric | | 105.4 | 102.6 | 91.6 | 87.4 | 105.6 | 119.6 | 127.1 | 119.9 | 112.1 | 94.4 | 96.1 | 108.2 |
| Trico Electric Cooperative | | 96.7 | 93.3 | 81.8 | 80.5 | 92.2 | 108.7 | 119.2 | 119.7 | 107.2 | 99.2 | 83.3 | 99.5 |
| **AR Coincidental Peak (ARCP)** | | **232.7** | **225.2** | **200.0** | **195.2** | **231.1** | **268.2** | **294.2** | **282.0** | **258.0** | **226.3** | **209.9** | **239.5** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2011

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** |
| **Adjusted Capacity** | | **514.5** | **514.5** | **519.7** | **525.2** | **525.3** | **525.6** | **526.5** | **526.1** | **525.1** | **514.3** | **514.3** | **514.5** |
| Power Sales Losses 2.97% | | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Power Sales Reserves 12.0% | | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| **Class A Capacity** | | **513.3** | **513.3** | **518.5** | **524.0** | **524.1** | **524.4** | **525.3** | **524.9** | **523.9** | **513.1** | **513.1** | **513.3** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 183.8 | 183.7 | 185.6 | 187.6 | 187.6 | 187.7 | 188.1 | 187.9 | 187.6 | 183.7 | 183.7 | 183.8 |
| Mohave Reserves @ 12% | | 19.2 | 19.2 | 19.4 | 19.6 | 19.6 | 19.6 | 19.6 | 19.6 | 19.6 | 19.2 | 19.2 | 19.2 |
| Mohave Losses @ 2.97% | | 4.7 | 4.7 | 4.8 | 4.8 | 4.8 | 4.8 | 4.9 | 4.9 | 4.8 | 4.7 | 4.7 | 4.7 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **159.8** | **159.8** | **161.5** | **163.2** | **163.2** | **163.3** | **163.6** | **163.4** | **163.1** | **159.8** | **159.8** | **159.8** |
| Mohave Electric 1999 PRS NC Peak | | 81.4 | 65.3 | 59.5 | 71.5 | 103.5 | 140.3 | 173.8 | 177.8 | 144.4 | 91.5 | 62.8 | 85.1 |
| **All Requirements (AR) Capacity** | | **329.5** | **329.5** | **332.9** | **336.4** | **336.5** | **336.7** | **337.3** | **337.0** | **336.3** | **329.4** | **329.4** | **329.5** |
| AR Losses 2.97% Based on ARCP | | 7.1 | 6.9 | 6.1 | 6.0 | 7.1 | 8.2 | 9.0 | 8.6 | 7.9 | 6.9 | 6.4 | 7.3 |
| AR Reserves 12.0% Based on ARCP | | 28.8 | 27.8 | 24.7 | 24.1 | 28.6 | 33.1 | 36.3 | 34.8 | 31.8 | 28.0 | 25.9 | 29.6 |
| **AR Losses & Reserves Based on ARCP** | | **35.9** | **34.7** | **30.8** | **30.1** | **35.6** | **41.3** | **45.3** | **43.5** | **39.7** | **34.9** | **32.3** | **36.9** |
| **Net All Requirements Capacity** | | **293.7** | **294.8** | **302.1** | **306.3** | **300.8** | **295.3** | **291.9** | **293.5** | **296.6** | **294.5** | **297.1** | **292.6** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.8 | 6.7 | 6.0 | 6.2 | 6.3 | 7.2 | 8.7 | 9.4 | 8.5 | 6.3 | 7.0 | 7.5 |
| Duncan Valley Electric Cooperative | | 4.3 | 4.3 | 3.8 | 3.8 | 4.3 | 4.9 | 5.2 | 4.7 | 4.5 | 4.0 | 4.2 | 4.5 |
| Graham County Electric Cooperative | | 20.0 | 18.8 | 17.2 | 17.8 | 23.1 | 28.2 | 34.6 | 28.8 | 26.2 | 22.6 | 19.7 | 20.4 |
| Sulphur Springs Valley Electric | | 107.7 | 104.8 | 93.6 | 89.2 | 108.1 | 122.4 | 130.1 | 122.5 | 114.4 | 96.5 | 98.4 | 110.7 |
| Trico Electric Cooperative | | 101.0 | 97.4 | 85.4 | 84.0 | 96.2 | 113.4 | 124.3 | 124.8 | 111.8 | 103.4 | 86.8 | 103.7 |
| **AR Coincidental Peak (ARCP)** | | **239.7** | **231.9** | **206.0** | **201.0** | **238.1** | **276.1** | **302.8** | **290.3** | **265.4** | **233.0** | **216.1** | **246.8** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2012

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 2.2 | 2.2 | 2.1 | 8.6 | 9.5 | 11.1 | 11.6 | 11.6 | 10.5 | 2.1 | 2.0 | 2.3 |
| Parker-Davis | ** Note 2 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| **Existing Resources** | | **523.8** | **523.7** | **523.5** | **535.5** | **536.5** | **538.4** | **539.9** | **539.4** | **537.3** | **523.5** | **523.5** | **523.9** |
| Electrical District 2 Firm | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Salt River Project Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 | 8.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** | **25.5** |
| **Adjusted Capacity** | | **498.3** | **498.2** | **498.0** | **510.0** | **511.0** | **512.9** | **514.4** | **513.9** | **511.8** | **498.0** | **498.0** | **498.4** |
| Power Sales Losses 2.97% | | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Power Sales Reserves 12.0% | | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| **Class A Capacity** | | **497.1** | **497.0** | **496.8** | **508.8** | **509.8** | **511.7** | **513.2** | **512.7** | **510.6** | **496.8** | **496.8** | **497.2** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 178.0 | 177.9 | 177.9 | 182.2 | 182.5 | 183.2 | 183.7 | 183.5 | 182.8 | 177.8 | 177.8 | 178.0 |
| Mohave Reserves @ 12% | | 18.6 | 18.6 | 18.6 | 19.0 | 19.0 | 19.1 | 19.2 | 19.2 | 19.1 | 18.6 | 18.6 | 18.6 |
| Mohave Losses @ 2.97% | | 4.6 | 4.6 | 4.6 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.7 | 4.6 | 4.6 | 4.6 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **154.8** | **154.8** | **154.7** | **158.4** | **158.7** | **159.3** | **159.8** | **159.6** | **159.0** | **154.7** | **154.7** | **154.8** |
| Mohave Electric 1999 PRS NC Peak | | 84.1 | 67.7 | 61.7 | 73.8 | 106.4 | 143.3 | 177.2 | 181.4 | 147.6 | 94.3 | 65.2 | 87.7 |
| **All Requirements (AR) Capacity** | | **319.2** | **319.1** | **319.0** | **326.7** | **327.3** | **328.5** | **329.5** | **329.1** | **327.8** | **318.9** | **318.9** | **319.2** |
| AR Losses 2.97% Based on ARCP | | 7.3 | 7.1 | 6.3 | 6.1 | 7.3 | 8.4 | 9.3 | 8.9 | 8.1 | 7.1 | 6.6 | 7.5 |
| AR Reserves 12.0% Based on ARCP | | 29.6 | 28.6 | 25.4 | 24.8 | 29.4 | 34.1 | 37.4 | 35.8 | 32.7 | 28.8 | 26.7 | 30.5 |
| **AR Losses & Reserves Based on ARCP** | | **37.0** | **35.7** | **31.7** | **31.0** | **36.7** | **42.5** | **46.6** | **44.7** | **40.8** | **35.9** | **33.3** | **38.0** |
| **Net All Requirements Capacity** | | **282.2** | **283.4** | **287.2** | **295.7** | **290.6** | **286.0** | **282.8** | **284.4** | **286.9** | **283.0** | **285.6** | **281.2** |
| ***1999 Power Requirements Study Class A Coincidental Peaks - MW*** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 6.9 | 6.8 | 6.0 | 6.3 | 6.4 | 7.3 | 8.8 | 9.5 | 8.6 | 6.4 | 7.1 | 7.6 |
| Duncan Valley Electric Cooperative | | 4.4 | 4.3 | 3.9 | 3.8 | 4.3 | 5.0 | 5.2 | 4.8 | 4.6 | 4.1 | 4.3 | 4.5 |
| Graham County Electric Cooperative | | 20.3 | 19.1 | 17.5 | 18.1 | 23.5 | 28.5 | 35.0 | 29.1 | 26.5 | 22.9 | 20.0 | 20.7 |
| Sulphur Springs Valley Electric | | 110.1 | 107.0 | 95.6 | 91.1 | 110.7 | 125.2 | 133.1 | 125.2 | 116.8 | 98.6 | 100.6 | 113.2 |
| Trico Electric Cooperative | | 105.3 | 101.5 | 89.0 | 87.5 | 100.3 | 118.1 | 129.5 | 130.0 | 116.4 | 107.6 | 90.3 | 107.9 |
| **AR Coincidental Peak (ARCP)** | | **246.9** | **238.7** | **212.1** | **206.8** | **245.2** | **284.2** | **311.6** | **298.6** | **272.9** | **239.7** | **222.3** | **254.0** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2013

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Salt River Project Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** |
| **Adjusted Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Power Sales Losses 2.97% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Power Sales Reserves 12.0% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Class A Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 187.1 | 187.0 | 188.9 | 190.9 | 190.9 | 191.0 | 191.4 | 191.2 | 190.8 | 187.0 | 187.0 | 187.1 |
| Mohave Reserves @ 12% | | 19.5 | 19.5 | 19.7 | 19.9 | 19.9 | 19.9 | 20.0 | 20.0 | 19.9 | 19.5 | 19.5 | 19.5 |
| Mohave Losses @ 2.97% | | 4.8 | 4.8 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.8 | 4.8 | 4.8 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **162.7** | **162.7** | **164.3** | **166.0** | **166.1** | **166.2** | **166.4** | **166.3** | **166.0** | **162.6** | **162.6** | **162.7** |
| Mohave Electric 1999 PRS NC Peak | | 86.8 | 70.2 | 64.0 | 76.1 | 109.2 | 146.3 | 180.6 | 185.0 | 150.9 | 97.2 | 67.7 | 90.4 |
| **All Requirements (AR) Capacity** | | **335.4** | **335.4** | **338.8** | **342.3** | **342.4** | **342.6** | **343.2** | **342.9** | **342.2** | **335.3** | **335.3** | **335.4** |
| AR Losses 2.97% Based on ARCP | | 7.5 | 7.3 | 6.5 | 6.3 | 7.5 | 8.7 | 9.5 | 9.1 | 8.3 | 7.3 | 6.8 | 7.8 |
| AR Reserves 12.0% Based on ARCP | | 30.5 | 29.5 | 26.2 | 25.5 | 30.3 | 35.1 | 38.4 | 36.8 | 33.6 | 29.6 | 27.4 | 31.4 |
| **AR Losses & Reserves Based on ARCP** | | **38.0** | **36.7** | **32.7** | **31.8** | **37.8** | **43.7** | **48.0** | **46.0** | **42.0** | **36.9** | **34.2** | **39.1** |
| **Net All Requirements Capacity** | | **297.4** | **298.7** | **306.2** | **310.5** | **304.6** | **298.8** | **295.2** | **296.9** | **300.3** | **298.4** | **301.1** | **296.3** |
| ***1999 Power Requirements Study Class A Coincidental Peaks - MW*** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 7.0 | 6.9 | 6.1 | 6.4 | 6.5 | 7.4 | 8.9 | 9.7 | 8.7 | 6.5 | 7.2 | 7.8 |
| Duncan Valley Electric Cooperative | | 4.4 | 4.4 | 3.9 | 3.9 | 4.4 | 5.1 | 5.3 | 4.8 | 4.6 | 4.1 | 4.3 | 4.6 |
| Graham County Electric Cooperative | | 20.6 | 19.4 | 17.7 | 18.4 | 23.8 | 28.8 | 35.5 | 29.5 | 26.8 | 23.2 | 20.3 | 21.0 |
| Sulphur Springs Valley Electric | | 112.5 | 109.2 | 97.7 | 93.0 | 113.4 | 128.1 | 136.1 | 127.9 | 119.3 | 100.8 | 102.9 | 115.8 |
| Trico Electric Cooperative | | 109.6 | 105.6 | 92.6 | 91.0 | 104.3 | 122.8 | 134.7 | 135.2 | 120.9 | 111.8 | 93.8 | 112.2 |
| **AR Coincidental Peak (ARCP)** | | **254.1** | **245.5** | **218.1** | **212.6** | **252.3** | **292.2** | **320.4** | **307.1** | **280.4** | **246.5** | **228.6** | **261.3** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2014

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Salt River Project Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** |
| **Adjusted Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Power Sales Losses 2.97% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Power Sales Reserves 12.0% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Class A Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 187.1 | 187.0 | 188.9 | 190.9 | 190.9 | 191.0 | 191.4 | 191.2 | 190.8 | 187.0 | 187.0 | 187.1 |
| Mohave Reserves @ 12% | | 19.5 | 19.5 | 19.7 | 19.9 | 19.9 | 19.9 | 20.0 | 20.0 | 19.9 | 19.5 | 19.5 | 19.5 |
| Mohave Losses @ 2.97% | | 4.8 | 4.8 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.8 | 4.8 | 4.8 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **162.7** | **162.7** | **164.3** | **166.0** | **166.1** | **166.2** | **166.4** | **166.3** | **166.0** | **162.6** | **162.6** | **162.7** |
| Mohave Electric 1999 PRS NC Peak | | 90.0 | 73.2 | 66.9 | 78.9 | 112.5 | 149.7 | 184.5 | 189.1 | 154.7 | 100.5 | 70.8 | 93.6 |
| **All Requirements (AR) Capacity** | | **335.4** | **335.4** | **338.8** | **342.3** | **342.4** | **342.6** | **343.2** | **342.9** | **342.2** | **335.3** | **335.3** | **335.4** |
| AR Losses 2.97% Based on ARCP | | 7.8 | 7.5 | 6.7 | 6.5 | 7.7 | 8.9 | 9.8 | 9.4 | 8.6 | 7.5 | 7.0 | 8.0 |
| AR Reserves 12.0% Based on ARCP | | 31.4 | 30.3 | 26.9 | 26.2 | 31.1 | 36.0 | 39.5 | 37.9 | 34.6 | 30.4 | 28.2 | 32.3 |
| **AR Losses & Reserves Based on ARCP** | | **39.1** | **37.8** | **33.6** | **32.7** | **38.9** | **45.0** | **49.3** | **47.2** | **43.1** | **37.9** | **35.2** | **40.2** |
| **Net All Requirements Capacity** | | **296.3** | **297.6** | **305.2** | **309.6** | **303.5** | **297.6** | **293.9** | **295.6** | **299.1** | **297.4** | **300.2** | **295.2** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 7.1 | 7.0 | 6.2 | 6.5 | 6.6 | 7.5 | 9.0 | 9.8 | 8.9 | 6.7 | 7.3 | 7.9 |
| Duncan Valley Electric Cooperative | | 4.5 | 4.4 | 4.0 | 3.9 | 4.5 | 5.1 | 5.3 | 4.9 | 4.7 | 4.2 | 4.4 | 4.6 |
| Graham County Electric Cooperative | | 21.0 | 19.7 | 18.0 | 18.7 | 24.1 | 29.2 | 35.9 | 29.8 | 27.1 | 23.5 | 20.6 | 21.4 |
| Sulphur Springs Valley Electric | | 115.0 | 111.5 | 99.9 | 94.9 | 116.1 | 131.0 | 139.2 | 130.8 | 121.8 | 103.0 | 105.3 | 118.5 |
| Trico Electric Cooperative | | 113.9 | 109.8 | 96.2 | 94.5 | 108.3 | 127.6 | 139.9 | 140.4 | 125.5 | 116.0 | 97.3 | 116.4 |
| **AR Coincidental Peak (ARCP)** | | **261.4** | **252.4** | **224.3** | **218.5** | **259.6** | **300.4** | **329.3** | **315.6** | **288.0** | **253.4** | **235.0** | **268.8** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2015

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Salt River Project Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| *Total Other Firm Loads* | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** |
| **Adjusted Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Power Sales Losses 2.97% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Power Sales Reserves 12.0% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Class A Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 187.1 | 187.0 | 188.9 | 190.9 | 190.9 | 191.0 | 191.4 | 191.2 | 190.8 | 187.0 | 187.0 | 187.1 |
| Mohave Reserves @ 12% | | 19.5 | 19.5 | 19.7 | 19.9 | 19.9 | 19.9 | 20.0 | 20.0 | 19.9 | 19.5 | 19.5 | 19.5 |
| Mohave Losses @ 2.97% | | 4.8 | 4.8 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.8 | 4.8 | 4.8 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **162.7** | **162.7** | **164.3** | **166.0** | **166.1** | **166.2** | **166.4** | **166.3** | **166.0** | **162.6** | **162.6** | **162.7** |
| Mohave Electric 1999 PRS NC Peak | | 93.5 | 76.5 | 70.1 | 82.1 | 116.1 | 153.5 | 188.6 | 193.5 | 158.8 | 104.2 | 74.1 | 97.1 |
| **All Requirements (AR) Capacity** | | **335.4** | **335.4** | **338.8** | **342.3** | **342.4** | **342.6** | **343.2** | **342.9** | **342.2** | **335.3** | **335.3** | **335.4** |
| AR Losses 2.97% Based on ARCP | | 8.0 | 7.7 | 6.8 | 6.7 | 7.9 | 9.2 | 10.0 | 9.6 | 8.8 | 7.7 | 7.2 | 8.2 |
| AR Reserves 12.0% Based on ARCP | | 32.3 | 31.1 | 27.7 | 26.9 | 32.0 | 37.0 | 40.6 | 38.9 | 35.5 | 31.2 | 29.0 | 33.2 |
| **AR Losses & Reserves Based on ARCP** | | **40.2** | **38.8** | **34.5** | **33.6** | **39.9** | **46.2** | **50.6** | **48.5** | **44.2** | **39.0** | **36.2** | **41.4** |
| **Net All Requirements Capacity** | | **295.2** | **296.6** | **304.3** | **308.7** | **302.4** | **296.4** | **292.6** | **294.4** | **298.0** | **296.3** | **299.2** | **294.1** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 7.3 | 7.2 | 6.4 | 6.7 | 6.8 | 7.7 | 9.1 | 10.0 | 9.1 | 6.8 | 7.5 | 8.0 |
| Duncan Valley Electric Cooperative | | 4.5 | 4.5 | 4.0 | 4.0 | 4.5 | 5.2 | 5.4 | 4.9 | 4.7 | 4.3 | 4.5 | 4.7 |
| Graham County Electric Cooperative | | 21.3 | 20.0 | 18.3 | 19.0 | 24.5 | 29.5 | 36.3 | 30.2 | 27.5 | 23.7 | 21.0 | 21.8 |
| Sulphur Springs Valley Electric | | 117.5 | 113.8 | 102.1 | 96.9 | 118.8 | 133.9 | 142.3 | 133.5 | 124.2 | 105.3 | 107.7 | 121.2 |
| Trico Electric Cooperative | | 118.1 | 113.9 | 99.8 | 98.0 | 112.3 | 132.2 | 145.0 | 145.5 | 130.1 | 120.2 | 100.8 | 120.6 |
| **AR Coincidental Peak (ARCP)** | | **268.8** | **259.4** | **230.6** | **224.5** | **266.8** | **308.6** | **338.2** | **324.1** | **295.6** | **260.4** | **241.5** | **276.3** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2016

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Salt River Project Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** |
| **Adjusted Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Power Sales Losses 2.97% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Power Sales Reserves 12.0% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **t Class A Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 187.1 | 187.0 | 188.9 | 190.9 | 190.9 | 191.0 | 191.4 | 191.2 | 190.8 | 187.0 | 187.0 | 187.1 |
| Mohave Reserves @ 12% | | 19.5 | 19.5 | 19.7 | 19.9 | 19.9 | 19.9 | 20.0 | 20.0 | 19.9 | 19.5 | 19.5 | 19.5 |
| Mohave Losses @ 2.97% | | 4.8 | 4.8 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.8 | 4.8 | 4.8 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **162.7** | **162.7** | **164.3** | **166.0** | **166.1** | **166.2** | **166.4** | **166.3** | **166.0** | **162.6** | **162.6** | **162.7** |
| Mohave Electric 1999 PRS NC Peak | | 97.5 | 80.4 | 73.8 | 85.8 | 120.2 | 157.7 | 193.2 | 198.2 | 163.3 | 108.4 | 78.0 | 101.1 |
| **All Requirements (AR) Capacity** | | **335.4** | **335.4** | **338.8** | **342.3** | **342.4** | **342.6** | **343.2** | **342.9** | **342.2** | **335.3** | **335.3** | **335.4** |
| AR Losses 2.97% Based on ARCP | | 8.2 | 7.9 | 7.0 | 6.8 | 8.1 | 9.4 | 10.3 | 9.9 | 9.0 | 7.9 | 7.4 | 8.4 |
| AR Reserves 12.0% Based on ARCP | | 33.1 | 32.0 | 28.4 | 27.7 | 32.9 | 38.0 | 41.7 | 39.9 | 36.4 | 32.1 | 29.8 | 34.1 |
| **AR Losses & Reserves Based on ARCP** | | **41.3** | **39.9** | **35.5** | **34.5** | **41.0** | **47.4** | **52.0** | **49.8** | **45.4** | **40.0** | **37.1** | **42.5** |
| **Net All Requirements Capacity** | | **294.1** | **295.5** | **303.3** | **307.8** | **301.3** | **295.1** | **291.2** | **293.1** | **296.9** | **295.3** | **298.2** | **292.9** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 7.4 | 7.3 | 6.5 | 6.8 | 6.9 | 7.8 | 9.3 | 10.1 | 9.2 | 6.9 | 7.7 | 8.2 |
| Duncan Valley Electric Cooperative | | 4.6 | 4.6 | 4.1 | 4.0 | 4.6 | 5.3 | 5.5 | 5.0 | 4.8 | 4.3 | 4.5 | 4.8 |
| Graham County Electric Cooperative | | 21.6 | 20.3 | 18.6 | 19.2 | 24.8 | 29.9 | 36.7 | 30.6 | 27.8 | 24.0 | 21.3 | 22.1 |
| Sulphur Springs Valley Electric | | 120.1 | 116.2 | 104.3 | 99.0 | 121.5 | 136.9 | 145.4 | 136.3 | 126.7 | 107.6 | 110.2 | 124.0 |
| Trico Electric Cooperative | | 122.4 | 118.0 | 103.4 | 101.5 | 116.3 | 137.0 | 150.2 | 150.7 | 134.7 | 124.4 | 104.3 | 124.8 |
| **AR Coincidental Peak (ARCP)** | | **276.2** | **266.4** | **236.9** | **230.5** | **274.0** | **316.8** | **347.1** | **332.7** | **303.2** | **267.3** | **248.0** | **283.9** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2017

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Salt River Project Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** |
| **Adjusted Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Power Sales Losses 2.97% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Power Sales Reserves 12.0% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Class A Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 187.1 | 187.0 | 188.9 | 190.9 | 190.9 | 191.0 | 191.4 | 191.2 | 190.8 | 187.0 | 187.0 | 187.1 |
| Mohave Reserves @ 12% | | 19.5 | 19.5 | 19.7 | 19.9 | 19.9 | 19.9 | 20.0 | 20.0 | 19.9 | 19.5 | 19.5 | 19.5 |
| Mohave Losses @ 2.97% | | 4.8 | 4.8 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.8 | 4.8 | 4.8 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **162.7** | **162.7** | **164.3** | **166.0** | **166.1** | **166.2** | **166.4** | **166.3** | **166.0** | **162.6** | **162.6** | **162.7** |
| Mohave Electric 1999 PRS NC Peak | | 101.5 | 84.2 | 77.5 | 89.6 | 124.2 | 161.9 | 197.7 | 202.9 | 167.8 | 112.6 | 81.9 | 105.0 |
| **All Requirements (AR) Capacity** | | **335.4** | **335.4** | **338.8** | **342.3** | **342.4** | **342.6** | **343.2** | **342.9** | **342.2** | **335.3** | **335.3** | **335.4** |
| AR Losses 2.97% Based on ARCP | | 8.4 | 8.1 | 7.2 | 7.0 | 8.4 | 9.7 | 10.6 | 10.1 | 9.2 | 8.1 | 7.6 | 8.7 |
| AR Reserves 12.0% Based on ARCP | | 34.0 | 32.8 | 29.2 | 28.4 | 33.7 | 39.0 | 42.7 | 40.9 | 37.3 | 32.9 | 30.5 | 35.0 |
| **AR Losses & Reserves Based on ARCP** | | **42.5** | **40.9** | **36.4** | **35.4** | **42.1** | **48.6** | **53.3** | **51.1** | **46.5** | **41.1** | **38.1** | **43.6** |
| **Net All Requirements Capacity** | | **293.0** | **294.5** | **302.4** | **306.9** | **300.3** | **293.9** | **289.9** | **291.8** | **295.7** | **294.3** | **297.2** | **291.8** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 7.5 | 7.3 | 6.5 | 6.8 | 6.9 | 7.9 | 9.3 | 10.1 | 9.3 | 7.0 | 7.7 | 8.2 |
| Duncan Valley Electric Cooperative | | 4.7 | 4.6 | 4.2 | 4.1 | 4.7 | 5.3 | 5.5 | 5.1 | 4.9 | 4.4 | 4.6 | 4.8 |
| Graham County Electric Cooperative | | 22.0 | 20.6 | 18.9 | 19.5 | 25.1 | 30.2 | 37.2 | 30.9 | 28.1 | 24.3 | 21.6 | 22.4 |
| Sulphur Springs Valley Electric | | 122.8 | 118.7 | 106.6 | 101.0 | 124.3 | 139.9 | 148.6 | 139.2 | 129.2 | 110.0 | 112.7 | 126.8 |
| Trico Electric Cooperative | | 126.7 | 122.1 | 106.9 | 105.0 | 120.2 | 141.7 | 155.4 | 155.9 | 139.3 | 128.6 | 107.8 | 129.0 |
| **AR Coincidental Peak (ARCP)** | | **283.6** | **273.4** | **243.1** | **236.5** | **281.2** | **324.9** | **356.0** | **341.2** | **310.8** | **274.3** | **254.5** | **291.4** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

Appendix B to Exhibit A-5

# Monthly Allocated Capacity for 2018

| All Values in MW Unless Indicated | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Apache ST-2 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache ST-3 | | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 | 175.0 |
| Apache CC-1 | | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 | 81.0 |
| Apache GT-2 | | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Apache GT-3 | | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 | 69.0 |
| PacifiCorp | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Public Service of New Mexico | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| SLCA - IP | ** Note 1 ** | 1.6 | 1.6 | 1.4 | 6.9 | 7.0 | 7.3 | 8.2 | 7.8 | 6.8 | 1.4 | 1.4 | 1.6 |
| Parker-Davis | ** Note 2 ** | 18.4 | 18.4 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 23.8 | 18.4 | 18.4 | 18.4 |
| **Existing Resources** | | **540.0** | **540.0** | **545.2** | **550.7** | **550.8** | **551.1** | **552.0** | **551.6** | **550.6** | **539.8** | **539.8** | **540.0** |
| Electrical District 2 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Salt River Project Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 15 Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Mesa 17.5 Contingent | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Cyprus Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cyprus Contingent | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Morenci Water & Electric Firm | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Firm Loads | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Other Contingent Loads | | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| **Power Sales Resources** | | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** | **17.5** |
| **Adjusted Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Power Sales Losses 2.97% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Power Sales Reserves 12.0% | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Class A Capacity** | | **522.5** | **522.5** | **527.7** | **533.2** | **533.3** | **533.6** | **534.5** | **534.1** | **533.1** | **522.3** | **522.3** | **522.5** |
| Mohave ACP - % | | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% | 35.8% |
| Mohave Gross Capacity - MW | | 187.1 | 187.0 | 188.9 | 190.9 | 190.9 | 191.0 | 191.4 | 191.2 | 190.8 | 187.0 | 187.0 | 187.1 |
| Mohave Reserves @ 12% | | 19.5 | 19.5 | 19.7 | 19.9 | 19.9 | 19.9 | 20.0 | 20.0 | 19.9 | 19.5 | 19.5 | 19.5 |
| Mohave Losses @ 2.97% | | 4.8 | 4.8 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.8 | 4.8 | 4.8 |
| **Partial Requirements Allocated Capacity (Mohave)** | | **162.7** | **162.7** | **164.3** | **166.0** | **166.1** | **166.2** | **166.4** | **166.3** | **166.0** | **162.6** | **162.6** | **162.7** |
| Mohave Electric 1999 PRS NC Peak | | 105.5 | 88.1 | 81.3 | 93.3 | 128.3 | 166.1 | 202.2 | 207.6 | 172.3 | 116.8 | 85.8 | 109.0 |
| **All Requirements (AR) Capacity** | | **335.4** | **335.4** | **338.8** | **342.3** | **342.4** | **342.6** | **343.2** | **342.9** | **342.2** | **335.3** | **335.3** | **335.4** |
| AR Losses 2.97% Based on ARCP | | 8.6 | 8.3 | 7.4 | 7.2 | 8.6 | 9.9 | 10.8 | 10.4 | 9.5 | 8.4 | 7.8 | 8.9 |
| AR Reserves 12.0% Based on ARCP | | 34.9 | 33.7 | 29.9 | 29.1 | 34.6 | 40.0 | 43.8 | 42.0 | 38.2 | 33.8 | 31.3 | 35.9 |
| **AR Losses & Reserves Based on ARCP** | | **43.6** | **42.0** | **37.3** | **36.3** | **43.2** | **49.9** | **54.7** | **52.4** | **47.7** | **42.1** | **39.1** | **44.8** |
| **Net All Requirements Capacity** | | **291.9** | **293.4** | **301.5** | **306.0** | **299.2** | **292.7** | **288.5** | **290.5** | **294.6** | **293.2** | **296.2** | **290.7** |
| **1999 Power Requirements Study Class A Coincidental Peaks - MW** | | | | | | | | | | | | | |
| Anza Electric Cooperative | | 7.6 | 7.4 | 6.6 | 6.9 | 7.0 | 8.0 | 9.4 | 10.2 | 9.4 | 7.1 | 7.9 | 8.3 |
| Duncan Valley Electric Cooperative | | 4.7 | 4.7 | 4.2 | 4.2 | 4.7 | 5.4 | 5.6 | 5.1 | 4.9 | 4.5 | 4.7 | 4.9 |
| Graham County Electric Cooperative | | 22.3 | 21.0 | 19.1 | 19.8 | 25.4 | 30.5 | 37.6 | 31.3 | 28.5 | 24.6 | 22.0 | 22.8 |
| Sulphur Springs Valley Electric | | 125.5 | 121.2 | 109.0 | 103.2 | 127.2 | 142.9 | 151.9 | 142.1 | 131.8 | 112.4 | 115.3 | 129.8 |
| Trico Electric Cooperative | | 131.0 | 126.2 | 110.5 | 108.5 | 124.2 | 146.4 | 160.6 | 161.1 | 143.9 | 132.8 | 111.3 | 133.3 |
| **AR Coincidental Peak (ARCP)** | | **291.1** | **280.5** | **249.5** | **242.5** | **288.6** | **333.2** | **365.1** | **349.9** | **318.5** | **281.4** | **261.1** | **299.1** |

Note 1: SLCA-IP capacity is not at CROD. It is at year 2000 Monthly Capacity repeated through 2020. The Monthly Capacity is further reduced by 7% beginning 10-01-2004.
Note 2: Parker-Davis hydro contract terminates 10-01-2008. It is assumed that allocation will be renewed and continue through 2020.

# SCHEDULE B

## TO PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT



CONFIDENTIAL

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# SCHEDULE B

1. Introduction

1.1 Purpose. This Schedule B establishes the amount of energy to be available to Mohave Electric Cooperative, Inc. (MEC or Member) for purchase pursuant to the Partial Requirements Capacity and Energy Agreement, entered into between Arizona Electric Power Cooperative, Inc. (AEPCO) and Member (Agreement), from MEC's AC in AEPCO Resources at the energy rate set forth in Exhibit A-1 of Rate Schedule A. Such amount is based upon the ACP and AC of MEC and the historical use of AEPCO Resources to serve MEC Total Load. In addition, this Schedule B specifies the methodology pursuant to which additional charges shall be made by AEPCO to MEC in the event that: 1) MEC requires capacity and/or energy from AEPCO Resources that is in excess of the amount of its AC in AEPCO Resources and in excess of the energy available to MEC associated with its AC in AEPCO Resources at the energy rate of Exhibit A-1 to Rate Schedule A, both as determined herein; or 2) MEC does not take its required minimum capacity and energy from AEPCO Resources because MEC has used energy from other sources that displaces the use of such minimum energy from AEPCO Resources. Such additional charges shall be billed to MEC pursuant to Rate Schedule A of the Agreement.

1.2 Objective. The objective of this Schedule B is to: 1) maintain minimum energy production from AEPCO's base-load, coal-fired units (Apache Units 2 and 3) in off-peak or light load periods that may otherwise be decreased by MEC's purchase of certain supplemental capacity and energy for its Total Load; 2) minimize imposing increased energy costs on AEPCO resulting from more frequent and increased use of gas-fired peaking and gas-fired steam units in peak or heavy load periods that may result from certain sales by MEC from its AC; and 3) minimize imposing on AEPCO increased maintenance costs and possible loss of life of Generating Resources of AEPCO.

1.3 Definitions. All capitalized terms used and not defined in this Agreement, including this Schedule B, shall have the respective meanings as set forth in Appendix A to the Agreement.

"AC Ratio" shall mean the ratio of the AC of MEC for a month of a year subsequent to 2000 as compared to the AC of MEC for the corresponding month of 2000.

"AEPCO Maximum Base Capacity" shall mean that amount of capacity on an hourly basis equal to the sum of AEPCO Maximum Coal Capacity plus AEPCO Must-Run Purchase Capacity.

"AEPCO Maximum Coal Capacity" shall mean that amount of capacity on an hourly basis equal to the maximum net rated output of Apache Units 2 and 3, which is a total of 350 MW from both such units, or 175 MW from each such unit individually.

"AEPCO Minimum Base Capacity" shall mean that amount of capacity on an hourly basis equal to the sum of AEPCO Minimum Coal Capacity, plus AEPCO Must-Run Purchase Capacity.

"AEPCO Minimum Coal Capacity" shall mean that amount of capacity on an hourly basis equal to the minimum output for safe and reliable operation of Apache Units 2 and 3 which totals 210 MW from both such units, or 105 MW from each unit individually.

"AEPCO Must-Run Purchase Capacity" shall mean that amount of capacity on an hourly basis equal to the sum of the seasonal or monthly capacity amount available to AEPCO pursuant to the Federal Hydropower Agreements, plus the monthly capacity amount which must be taken or paid for by AEPCO pursuant to the PacifiCorp Purchase Agreement, as such amounts are in effect in Off-Peak Hours or Peak Hours, as applicable.

"Allocated Capacity Deficiency" shall mean that amount of capacity by which the AC of MEC is insufficient to meet the demand of the Net Total Load of MEC.

"Allocated Capacity Excess" shall mean that amount of capacity by which the AC of MEC exceeds the sum of the coincident demands of MEC AEPCO Load and MEC AEPCO Sales.

"Average Daily Load Curve(s)" shall mean the profile of the average hourly demands of MEC Total Load for the period 1995 through 1999, which profile is in the form of an integrated curve over a twenty-four (24) hour day.

"Class A Total Load" shall mean the sum of MEC Total Load plus Total Load of All Requirements Members.

"Federal Hydropower Agreement(s)" shall consist of the following contracts:

a) Contract No. 87-BCA-10001 for Firm Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated March 9, 1989; Amendment No. 1, dated March 9, 1989; Amendment No. 2, dated December 29, 1989; Amendment No. 3, dated June 9, 1992; and Amendment No. 4, dated March 5, 1997; Amendment No. 5, dated August 20, 1999; and as it may be amended from time to time, and its successor agreement(s) (SLCA Integrated Projects Agreement); and

b) Contract No. 87-BCA-10085 Electric Service between Western Area Power Administration and Arizona Power Pooling Association, dated February 25, 1988, as it may be amended from time to time, and its successor agreement(s) (Parker-Davis Project Agreement).

"MEC AEPCO Resource Profile" shall mean a profile of hourly capacity and energy from AEPCO Resources that is available to MEC over a twenty-four (24) hour day that is determined in accordance with Section 6 hereof.

"MEC AEPCO Profile Capacity" shall mean the portion of AC that is available to MEC in conjunction with MEC AEPCO Profile Energy.

"MEC AEPCO Profile Energy" shall mean the portion of Schedule A Energy that is derived from the MEC AEPCO Resource Profiles.

"MEC Total Load" or "MEC's Total Load" shall mean the historical total of the demands and energy requirements, including distribution losses but not including reserves or transmission losses, of the loads located within the Member's Distribution Service Area of MEC (or served from line extensions therefrom).

"PacifiCorp Purchase Agreement" shall mean the restated Power Sales Agreement between PacifiCorp and AEPCO, dated April 27, 1998, and Amendment No. 1, dated August 3, 1998.

"Schedule A Energy" shall mean the energy available to MEC from its AC in AEPCO Resources at the energy rate set forth in Exhibit A-1 to Rate Schedule A, as determined pursuant to Section 6.5 hereof.

"Schedule B Energy" shall mean energy available to MEC from its AC in AEPCO Resources in excess of Schedule A Energy, which is billed to MEC at the rates set forth in, or determined pursuant to, this Schedule B.

"Total Load of All Requirements Members" shall mean the sum of the total loads served from AEPCO Resources of each of the All Requirements Members, excluding reserves and transmission losses.

2. MEC's Historic Use of AEPCO Resources.

2.1 Demand Coincident with All Requirements Members. The 1995 through 1999 monthly demands of MEC Total Load and the Total Load of All Requirements Members coincident with AEPCO Member Peak Demand, and the average of such demands over such period, are set forth in Table B-1.1, attached hereto. Such average demands of each month for MEC and for All Requirements Members from Table B-1.1 shall be used in this Schedule B in the determination of the respective shares of MEC and the All Requirements Members in: (i) AEPCO Minimum Coal Capacity; (ii) AEPCO Must-Run Purchase Capacity; and (iii) AEPCO Maximum Coal Capacity.

2.2 MEC's Individual Peak and Monthly Energy. Table B-1.2 attached hereto sets forth: (i) the monthly 1995 through 1999 demands and the average demand of MEC Total Load at the times of peak demand of MEC's system; and (ii) the monthly energy consumed by MEC Total Load during the 1995 through 1999 period and the average

monthly amount thereof. These average monthly demand and energy data shall be used in the determination of the monthly amounts of capacity and energy to be available to MEC from AEPCO Resources pursuant to Section 6 hereof at the rates and Fixed Charge set forth in Exhibit A-1 to Rate Schedule A.

3. MEC Activities Related to Allocated Capacity Deficiency and Excess.

3.1 Allocated Capacity Deficiency. If MEC is utilizing a supply of energy supplemental to that available from the AC of MEC and is not taking its required share of AEPCO Minimum Base Capacity, MEC shall pay a charge as set forth in Section 7.2.2 hereof.

3.2 Allocated Capacity Excess. Pursuant to the Agreement, MEC has the right to use energy from its Allocated Capacity Excess. To the extent that such energy is provided from MEC's share of AEPCO Maximum Base Capacity (as determined in accordance with Section 5.3 hereof), MEC shall be billed and pay for such capacity and energy at the O&M and energy rates set forth in Exhibit A-1 to Rate Schedule A to the Agreement. To the extent that such energy is provided from other AEPCO Resources (as determined pursuant to Section 6 hereof), MEC shall be billed and pay for such capacity pursuant to Rate Schedule A, and for such energy pursuant to Section 7.2.3 hereof.

4. AEPCO Minimum Base Capacity.

4.1 Mutual Cooperation. AEPCO has in the past experienced and may in the future encounter minimum loading problems on the Apache Units 2 and 3 during periods of lower loads. Such minimum loading problems may arise in part because of the requirements of certain Power Purchase Resources to schedule and use energy during such periods. Purchases of supplemental energy by MEC during such load periods may aggravate this problem. In order to avoid aggravating this minimum loading problem, MEC shall share minimum energy obligations with respect to the Apache Units 2 and 3 and the must-run requirements of certain Power Purchase Resources in those hours. AEPCO shall be responsible for the similar minimum energy obligations determined for All Requirements Members and Power Sales Loads.

4.2 AEPCO Minimum Coal Capacity. Attached hereto as Table B-2 is the initial tabulation of AEPCO Minimum Coal Capacity, which shall be a portion of AEPCO Minimum Base Capacity, and shall be allocated among MEC , All Requirements Members and certain Power Sales Loads. Table B-2 illustrates the result of the methodology set forth in Section 4.2.1 below to allocate AEPCO Minimum Coal Capacity, and sets forth MEC's share thereof. The monthly contract demands of such certain Power Sales Loads and the actual average of the monthly peak demands of the Total Load of All Requirements Members and of MEC Total Load as set forth in Table B-1.1 are utilized to produce the results displayed in Table B-2.

4.2.1 Methodology. The methodology hereunder utilizes defined terms which are used in the captions of Table B-2 as clarified in Attachment A hereto.

4.2.1.1 Class A Total Load is calculated by adding the average demands of the Total Load of All Requirements Members to the average demands of MEC Total Load from Table B-1.1.

4.2.1.2 The contract demands of all Power Sales Loads except for any Power Sale Loads that obligate the purchaser to a share of AEPCO Minimum Coal Capacity (as of the Effective Date, the only such Power Sale Load is that of Morenci Water and Electric Co. (MW&E) pursuant to Service Schedule A, as amended, to the AEPCO/MW&E Interconnection Agreement, dated September 30, 1997) shall be added to provide Power Sales Load without MW&E.

4.2.1.3 Class A Total Load shall be added to Power Sales Load without MW&E to provide AEPCO Delivered Load without MW&E.

4.2.1.4 The allocation percentage shares for Power Sales Load without MW&E and Class A Total Load as percentages of AEPCO Delivered Load without MW&E shall be calculated.

4.2.1.5 The contractually determined capacity share allocated to MW&E of 35 MW of AEPCO Minimum Coal Capacity is subtracted from the 210 MW of AEPCO Minimum Coal Capacity to determine the remaining capacity of AEPCO Minimum Coal Capacity to be allocated between Power Sales Load without MW&E and Class A Total Load. Such remaining capacity of AEPCO Minimum Coal Capacity shall be multiplied by the percentage shares determined in Section 4.2.1.4 hereof, to determine the capacity share of remaining AEPCO Minimum Coal Capacity allocated to Power Sales Load without MW&E and to Class A Total Load.

4.2.1.6 MEC's monthly share of the AEPCO Minimum Coal Capacity shall be the product of the ACP of MEC multiplied by the capacity share of remaining AEPCO Minimum Coal Capacity allocated to Class A Total Load determined in Section 4.2.1.5 hereof.

4.3 AEPCO Must-Run Purchase Capacity. AEPCO Must-Run Purchase Capacity shall be a portion of AEPCO Minimum Base Capacity, and shall be allocated among the Total Load of All Requirements Members, MEC Total Load and Power Sales Loads. Table B-3 attached hereto: (i) is the initial tabulation of the results of such allocation; (ii) illustrates the methodology of allocation, and (iii) sets forth MEC's share of AEPCO Must-Run Purchase Capacity for 2000. AEPCO Must-Run Purchase Capacity consists of the contract demands established pursuant to the Federal Hydropower Agreements and the PacifiCorp Purchase Agreement, as stated separately for Peak Hours and Off-Peak Hours. The component of AEPCO Must-Run Purchase Capacity from the Federal Hydropower Agreements shall be determined in accordance with Section 4.3.1 below. The component of AEPCO Must-Run

Purchase Capacity from the PacifiCorp Purchase Agreement shall be determined in accordance with Section 4.3.2 below.

4.3.1 Must-Run from Federal Hydropower Agreements.

4.3.1.1 For each month, the component of AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements shall be allocated between MEC Total Load and the Total Load of All Requirement Members. MEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements shall be the product of MEC's ACP multiplied by the amount of AEPCO Must-Run Purchase Capacity from the Federal Hydropower Purchase Agreements. The amount of the component of AEPCO Must-Run Purchase Capacity from the Federal Hydropower Agreements for Off-Peak Hours and for Peak Hours shall be determined pursuant to Sections 4.3.1.2 and 4.3.1.3 hereof, respectively.

4.3.1.2 For Off-Peak Hours, the component of AEPCO Must-Run Purchase Capacity from the Federal Hydropower Agreements shall be as established by the respective project agreements. The Parker-Davis Project Agreement establishes such capacity in Off-Peak Hours as twenty-five (25%) percent of the energy available to AEPCO in each month divided by the number of Off-Peak Hours occurring in such month. The SLCA Integrated Projects Agreement establishes such capacity in Off-Peak Hours as thirty-five (35%) percent of the Contract Rate of Delivery (as such term is defined in the SLCA Integrated Projects Agreement).

4.3.1.3 For Peak Hours, the component of AEPCO Must-Run Purchase Capacity from the Federal Hydropower Agreements is established as the lesser of AEPCO's Contract Rate of Delivery (as defined in the respective project agreement) or the highest rate of delivery established by Western pursuant to the respective project agreements as set forth in writing and provided to AEPCO by Western.

4.3.1.4 Table B-3.1 attached illustrates for year 2000 the component of AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements and MEC's share thereof.

4.3.1.5 In the event that, during the term of this Agreement, MEC receives, pursuant to a contract between MEC and Western Area Power Administration (Western), an individual allocation of federal hydropower from either or both of SLCA Integrated Projects and Parker-Davis Project (the "Affected Project(s)"), MEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements from an Affected Project in which MEC receives such

an individual allocation shall be: (i) the positive amount, if any, resulting from subtracting such MEC individual allocation from the product of MEC's ACP multiplied by AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements for such Affected Project; or, (ii) if AEPCO is advised in writing by Western that AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements for such Affected Project has been reduced in order for MEC to receive an individual allocation, MEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements for such Affected Project shall be zero. Such modification of MEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements shall be deemed to be a Minor Resource Modification for the purposes of the Agreement. As soon as practicable following notification to AEPCO by MEC of an MEC individual allocation in Affected Project(s), AEPCO shall prepare and provide to MEC the amount of MEC's share of AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements resulting from this Section 4.3.1.5, as well as revised tables and exhibits reflecting such amount and the resulting AC of MEC for the purposes of (i) this Schedule B pursuant to Section 8 hereof; and (ii) the Agreement pursuant to Section 3.3.1.2 thereof, including Appendix B to Exhibit A-5 to Rate Schedule A. Such revised tables and exhibits shall be effective on the day that MEC first receives a delivery of federal hydropower pursuant to the contract between MEC and Western.

4.3.2 Must-Run from PacifiCorp Purchase Agreement.

4.3.2.1 The component of AEPCO Must-Run Purchase Capacity from the PacifiCorp Purchase Agreement shall be the monthly contract capacity set forth in Appendix A to the PacifiCorp Purchase Agreement, and shall be deemed to be applicable exclusively in Peak Hours. Such contract capacity shall be allocated between Class A Total Load and certain Power Sales Loads as set forth in Table B-3.2, attached hereto. MEC's share of AEPCO Must-Run Purchase Capacity from the PacifiCorp Purchase Agreement is derived in Table B-3-2 by multiplying the share of AEPCO Must-Run Purchase Capacity allocated to Class A Total Load by MEC's ACP.

4.3.2.2 Table B-3.2 shall use the contract demands of Power Sales Loads that are not served exclusively from Apache Units 2 and 3 (captioned as "Power Sales Load without Base" in Table B-3-2), and the sum of the historical average of the actual demands of the Total Load of All Requirements Members, and MEC Total Load, as set forth in Table B-1.1, to allocate the contract demands of the

PacifiCorp Purchase Agreement between Class A Total Load and such Power Sales Loads.

4.4 MEC's Share of AEPCO Minimum Base Capacity. MEC's monthly share of AEPCO Minimum Base Capacity which MEC shall purchase from AEPCO pursuant to the Agreement, shall be the sum of MEC's share of AEPCO Minimum Coal Capacity (determined as set forth in Section 4.2 hereof), plus MEC's share of AEPCO Must-Run Purchase Capacity (determined as set forth in Section 4.3 hereof). Included in the data of Table B-7 is MEC's monthly share of AEPCO Minimum Base Capacity.

5. AEPCO Maximum Base Capacity.

5.1 Mutual Cooperation. While operating above minimums, AEPCO has in the past experienced and may in the future encounter periods when it has capacity and energy available from Apache Units 2 and 3 and AEPCO Must-Run Purchase Capacity that is surplus to AEPCO Total Load. Pursuant to the Agreement, MEC has the right to sell its Allocated Capacity Excess. The exercise of such right could cause AEPCO to operate its Resources uneconomically, thereby detrimentally affecting the energy rates of the Class A Members. However, MEC's use of that portion of its Allocated Capacity Excess that is available from MEC's share of AEPCO Maximum Base Capacity could be beneficial. This Section 5 sets forth the method for determination of MEC's share of AEPCO Maximum Base Capacity.

5.2 AEPCO Maximum Coal Capacity. Attached hereto as Table B-4 is the tabulation of AEPCO Maximum Coal Capacity, which shall be a portion of AEPCO Maximum Base Capacity, and shall be allocated among MEC Total Load, the Total Load of All Requirements Members and certain Power Sales Loads. Table B-4 illustrates the result of the methodology set forth in Section 5.2.1 below to allocate AEPCO Maximum Coal Capacity, and sets forth MEC's share thereof. The monthly contract demands of certain Power Sales Loads and the monthly actual average demands of the Total Load of All Requirements Members and of MEC Total Load as set forth in Table B-1.1 are utilized to produce the results displayed in Table B-4.

5.2.1 Methodology. The methodology hereunder utilizes defined terms which are used in the captions of Table B-4 and clarified in Attachment A hereto.

5.2.1.1 Class A Total Load shall be determined in the same manner as set forth in Section 4.2.1.1 hereof.

5.2.1.2 The contract demands of all Power Sales Loads that do not have a share of AEPCO Maximum Coal Capacity and are not priced exclusively on costs of Apache Units 2 and 3 (as of the Effective Date, the Power Sales Loads of Cyprus, MW&E Non-base and the 15.0 MW City of Mesa agreement) shall be added to provide Power Sales Load without Share of Maximum Coal Capacity .

5.2.1.3 Class A Total Load shall be added to Power Sales Load without Share of Maximum Coal Capacity to provide AEPCO Delivered Load without Share of Maximum Coal Capacity .

5.2.1.4 The allocation percentage shares for such Power Sales Load without Share of Maximum Coal Capacity and Class A Total Load as percentages of AEPCO Delivered Load without Share of Maximum Coal Capacity shall be calculated.

5.2.1.5 The capacity share allocated to Power Sales Load that have a share of AEPCO Maximum Coal Capacity and are priced exclusively on the costs of Apache Units 2 and 3 (as of the Effective Date, the Power Sales Loads of MW&E, SRP, ED-2 and the 17.5 MW of City of Mesa agreements) shall then be subtracted from the 350 MW of AEPCO Maximum Coal Capacity to determine the remaining capacity of AEPCO Maximum Coal Capacity to be allocated between Power Sales Load without Share of Maximum Coal Capacity and Class A Total Load. Such remaining capacity of AEPCO Maximum Coal Capacity shall be multiplied by the percentage shares determined in Section 5.2.1.4 hereof, to determine the capacity share of remaining AEPCO Maximum Coal Capacity allocated to Power Sales Load without Share of Maximum Coal Capacity and to Class A Total Load.

5.2.1.6 MEC's monthly share of AEPCO Maximum Coal Capacity shall be the product of the ACP of MEC multiplied by the capacity share of remaining AEPCO Maximum Coal Capacity allocated to Class A Total Load determined in Section 5.2.1.5 hereof.

5.3 MEC's Share of AEPCO Maximum Base Capacity. MEC's monthly share of such AEPCO Maximum Base Capacity shall be the sum of MEC's share of AEPCO Maximum Coal Capacity (determined as set forth in Section 5.2 hereof), plus MEC's share of AEPCO Must-Run Purchase Capacity, determined as set forth in Section 4.3 hereof. Included in the data of Table B-7 is MEC's monthly share of AEPCO Maximum Base Capacity.

6. AEPCO and MEC Capacity and Energy Obligations.

6.1 Introduction. Pursuant to the Agreement, AEPCO makes capacity and energy available to MEC for purchase in amounts up to MEC's AC and associated energy. This Section 6 establishes a maximum amount of Schedule A Energy available to MEC for purchase pursuant to the Agreement and establishes the MEC AEPCO Profile Capacity which is associated with Schedule A Energy. MEC shall pay for its use of Schedule B Energy at the rates and additional charges set forth in, and determined pursuant to, Section 7 hereof. MEC also may be subject to additional charges pursuant to Section 7.2.4 related to the failure of MEC to use its MEC AEPCO Profile Capacity. The methodology set forth hereunder in this Section 6

utilizes defined terms which are identified hereunder, or in the tables and exhibits appended hereto.

6.2 Average Daily Load Curves. The aggregate amount of energy to be available to MEC for purchase under the Agreement as Schedule A Energy each month shall be determined from MEC's average historic use of energy from AEPCO Resources as set forth in Table B-1.2. Such Schedule A Energy shall be available each month to MEC in similar hours and patterns as MEC has historically used energy purchased from AEPCO, but the peak use of such energy shall not exceed AC.

6.2.1 The historic use by MEC of energy from AEPCO Resources is derived from the average of the 1995 through 1999 actual hourly MEC Total Load. In order to summarize the historic patterns of use of such energy, five (5) Average Daily Load Curves (ADLC) for each month have been developed based upon such historical data, each such curve representing each hour's energy of each particular day of such month, as follows:

6.2.1.1 A Peak Day ADLC, which shall represent the day of the month of the highest demand of MEC Total Load ;

6.2.1.2 A Minimum Peak ADLC, which shall represent the day of the month of lowest peak demand during Peak Hours of MEC Total Load;

6.2.1.3 A Non-Holiday Weekday ADLC, which shall represent the average of MEC Total Load for all remaining weekdays of the month;

6.2.1.4 A Saturday ADLC, which shall represent the average of MEC Total Load for all Saturdays of the month; and

6.2.1.5 A Sunday and Holiday ADLC, which shall represent the average of MEC Total Load for all Sundays and Holidays occurring in the month.

6.2.2 Such ALDC's for each month developed for purposes of this Schedule B are set forth in the graphs of Exhibit B-1 attached hereto.

6.3 MEC AEPCO Resource Profiles. The following characteristics of the ADLC's of MEC were observed: 1) the peak demand and monthly aggregate energy data that would result from the ADLC's for the months of January through June and October through December is different than the peak demand and aggregate energy set forth for such months in Table B-1.2; and, 2) the peak demands of the ALDC's of July, August and September exceed the AC of MEC for such months in year 2000 as set forth in Appendix B to Exhibit A-5 of Rate Schedule A.

6.3.1 To adjust for such ADLC characteristics, five (5) corresponding MEC AEPCO Resource Profiles were constructed.

6.3.1.1 The MEC AEPCO Resource Profiles for January through June and October through December were developed by multiplying the hourly amounts of energy from the ADLC's of January through June and October through December, respectively, by the ratio obtained by comparing the 1995-1999 average peak demand for each such month as set forth in Table B-1.2 to the peak demand of the Peak Day ADLC.

6.3.1.2 The MEC AEPCO Resource Profiles for the months of July, August and September, were developed by multiplying the hourly amounts of energy from the ADLC's of July, August and September, respectively, by the ratio obtained by comparing the AC of MEC for such month to the peak demand of the Peak Day ADLC.

6.3.1.3 Such MEC AEPCO Resource Profiles, which consist of a Peak Day Profile, a Minimum Peak Profile, a Non-Holiday Weekday Profile, a Saturday Profile, and a Sunday & Holiday Profile, are attached as Exhibit B-2.

6.3.2 The MEC AEPCO Resource Profiles shall be used to obtain MEC AEPCO Profile Energy for each month of 2000 and each subsequent year pursuant to Sections 6.4 and 6.5 below.

6.3.3 The MEC AEPCO Profile Capacity for each month of 2000 shall equal the lesser of the AC for such month as set forth in Appendix B to Exhibit A-5 of Rate Schedule A, or the average peak demand for such month set forth in Table B-1.2. The MEC AEPCO Profile Capacity for each month of 2000 shall be as set forth as "2000 Resource Peak Demand" on Table B-5.1.

6.4 Determining Hourly Schedule A Energy Available in 2000. The MEC AEPCO Resource Profiles developed pursuant to Section 6.3.1 hereof for each month shall be used to determine MEC AEPCO Profile Energy for each hour of each month of 2000, in accord with the following methodology:

6.4.1 The twenty-four (24) hourly amounts from the Peak Day Profile shall be used for one non-Holiday weekday of the month;

6.4.2 The twenty-four (24) hourly amounts from the Lowest Peak Profile shall be used for one weekday of the month;

6.4.3 The twenty-four (24) hourly amounts from the Weekday Profile shall be used for all the remaining weekdays of the month;

6.4.4 The twenty-four (24) hourly amounts from the Sunday and Holiday Profile shall be used for all Sundays and Holidays occurring in the month; and

6.4.5 The twenty-four (24) hourly amounts from the Saturday Profile shall be used for all Saturdays of the month.

6.4.6 The calculated MEC AEPCO Profile Energy for each hour for each month of 2000 is tabulated in Table B-6 in Exhibit B-3 attached hereto.

6.4.7 Schedule A Energy available to MEC in each hour shall be the greater of the amount of MEC AEPCO Profile Energy of such hour, or the energy associated with MEC's share of AEPCO Maximum Base Capacity amount for such hour, as determined in accordance with Section 5 hereof, and as set forth for 2000 in Table B-6 of Exhibit B-3.

6.5 Determining Schedule A Energy and MEC AEPCO Profile Capacity Available in Subsequent Years. The amounts of Schedule A Energy and MEC AEPCO Profile Capacity for each month of any subsequent year shall be determined as follows:

6.5.1 Schedule A Energy. In any hour of any month of years subsequent to 2000, Schedule A Energy available to MEC shall be the greater of the amount of MEC AEPCO Profile Energy applicable in such time periods, or the energy associated with MEC's share of AEPCO Maximum Base Capacity. The monthly and hourly amounts of MEC AEPCO Profile Energy, plus the corresponding monthly and hourly amounts of MEC's share of AEPCO Maximum Base Capacity shall be determined as follows:

6.5.1.1 AC Ratios. The AC Ratios set forth in Tables B-5.1 and B-5.2, shall be used to determine an amount of MEC AEPCO Profile Energy and MEC AEPCO Profile Capacity.

6.5.1.2 Monthly MEC AEPCO Profile Energy. The aggregate amount of MEC AEPCO Profile Energy available each month in years subsequent to 2000 shall be obtained by multiplying the aggregate amount of MEC AEPCO Profile Energy available for such month in 2000 from Table B-6, by the AC Ratio for such month. Table B-5.2 contains the monthly totals of the MEC AEPCO Profile Energy available for each month of each year through the term of the Agreement.

6.5.1.3 Hourly MEC AEPCO Profile Energy. The amount of MEC AEPCO Profile Energy available for each hour of each month of a year subsequent to 2000 shall be the product of the MEC AEPCO Profile Energy amount for such hour in the corresponding month of 2000, multiplied by the AC Ratio for such month.

6.5.1.4 MEC Share of AEPCO Maximum Base Capacity. MEC's share of Maximum Base Capacity for 2000 is set out in Table B-7 of Exhibit B-3. In order to determine MEC's share of AEPCO Maximum Base Capacity for years subsequent to 2000, the amount of MEC's

share of AEPCO Must-Run Purchase Capacity from Federal Hydropower Agreements must be determined. AEPCO shall provide MEC with a revised Table B-7 to Exhibit B-3 setting forth the amount of MEC's share of AEPCO Maximum Base Capacity as soon as practicable after AEPCO receives notice of the amounts of AEPCO Must-Run Purchase Capacity available pursuant to the Federal Hydropower Agreements.

6.5.2 MEC AEPCO Profile Capacity. Each month's amount of MEC AEPCO Profile Capacity available in years subsequent to 2000 shall be obtained by multiplying the amount of MEC AEPCO Profile Capacity available in the corresponding month of 2000 by the AC Ratio for such month. Table B-5.1 contains the monthly amounts of MEC AEPCO Profile Capacity available for each month of each year during the term of the Agreement.

6.5.3 Summary Table for MEC AEPCO Profile Capacity and Energy. Attached as Table B-5 is a summary by month and year through the term of the Agreement of the MEC AEPCO Profile Capacity and MEC AEPCO Profile Energy.

6.6 Identification of Schedule A Energy Within Member Billing Energy. AEPCO shall each month during the term of this Agreement prepare and deliver to MEC an hourly tabulation of the amount of energy sold by AEPCO to MEC as Member Billing Energy and shall also identify the amount of such energy billed as Schedule A Energy. Such tabulation shall indicate the additional amounts of Schedule A Energy unused and available from MEC's share of AEPCO Maximum Base Capacity and the portion of Schedule A Energy unused and available from MEC's share of AEPCO Resources other than those included in AEPCO Maximum Base Capacity. Such tabulation shall also show the amount of energy billed and unused and available as Schedule B Energy. Tables B-7 and B-8 of Exhibit B-3 illustrate such tabulations. Any use of Schedule B Energy shall be subject to additional charges as set forth in Section 7 hereof.

7. Additional Charges.

7.1 Ordinary Service. Unless otherwise provided in this Schedule B, the energy sold by AEPCO to MEC pursuant to the Agreement shall be at the rates and Fixed Charge set forth in Exhibit A-1 to Rate Schedule A to the Agreement.

7.2 Additional Charges. In addition to the charges related to ordinary service, MEC shall pay AEPCO the following additional amounts resulting from this Schedule B.

7.2.1 Schedule B Energy. Except as set forth in Section 7.2.3 below, AEPCO shall bill MEC monthly for each hour's use by MEC of Schedule B Energy in an amount obtained by multiplying Schedule B Energy delivered in each such hour of the billing month by the highest cost energy provided from AEPCO Resources in such hour.

7.2.2 Minimum Base Capacity Violations. In the event that MEC has replaced its use of AEPCO Resources with a Member Resource in any hour and fails to take energy from AEPCO sufficient to meet MEC's share of AEPCO Minimum Base Capacity, AEPCO shall bill MEC the amount obtained by multiplying the lesser of the amount of Member Resource used in such hour, or the amount of MEC's deficiency in its share of AEPCO Minimum Base Capacity by the applicable of: (i) the energy rate set forth in Exhibit A-1 of Rate Schedule A; or (ii) to the extent AEPCO sold all or a portion of such energy to others, any positive difference obtained by subtracting the energy rate received by AEPCO related to such sale from the energy rate set forth in Exhibit A-1 of Rate Schedule A (Schedule B Minimum Energy Charge).

7.2.3 Capacity and Energy Above AC. In the event that MEC's use of AEPCO Resources exceeds its AC, as set forth in Appendix B to Exhibit A-5 of Rate Schedule A (or as such AC is reduced during Off-Peak Hours), MEC shall pay AEPCO each month for such additional capacity and associated energy as follows: (i) an additional capacity charge in an amount equal to the product of AEPCO's All Requirements demand rate, multiplied by the maximum kW demand experienced in the billing period that is in excess of MEC's AC (Schedule B Demand Overrun Charge); and (ii) an additional energy charge which shall be an amount equal to the energy rate of the highest cost resource dispatched or purchased by AEPCO in the hour(s) that MEC used AEPCO Resources above its AC, multiplied by the amount of such excess energy served in such hour(s) (Schedule B Overrun Energy Charge).

7.2.4 Minimum O&M Charge. In the event MEC uses a Member Resource in any month and by such use has caused MEC's Member Billing Demand to be less than the MEC AEPCO Profile Capacity for that month, AEPCO shall bill MEC and MEC shall pay an amount equal to the product of the O&M Rate set forth in Exhibit A-1 to Rate Schedule A, multiplied by the difference between the MEC AEPCO Profile Capacity and Member Billing Demand. Such difference shall not exceed the amount of Member Resource so used.

8. Revisions to Tables and Exhibits.

From time to time events will occur which will necessitate the revision of the Tables and Exhibits attached to this Schedule B. Such revisions shall only be undertaken in accordance with the following:

8.1 Tables B-1.1 and B-1.2 shall not be modified except by mutual agreement of the Parties.

8.2 Tables B-2, B-3.2, B-4, B-5, B-5.1 and B-5.2 and Exhibit B-3, comprised of Tables B-6, B-7 and B-8 shall be modified only when the AC of MEC is modified pursuant to Sections 3.3, 3.4 or 3.5 of the Agreement, AEPCO shall provide to MEC any such modified Table or Exhibit at least fifteen (15) business days before such modification becomes effective.

8.3 Table B-3.1 shall be modified only when notice is received from Western Area Power Administration (Western) changing the allocation of capacity or energy from the Salt Lake City Integrated Projects or the Parker Davis Project to which AEPCO is entitled. AEPCO shall provide any modified Table B-3.1 as soon as practicable after such notice from Western.

8.4 Table B-3 shall be modified as required by modifications to Tables B-3.1 and B-3.2.

8.5 Whenever a Table or Exhibit is revised such revised Table or Exhibit shall be based upon the same methodology that was used to develop the initial Table or Exhibit. When a Table or Exhibit is revised all other Tables or Exhibits using data derived from such Table or Exhibit shall be revised to conform to any changes in such data.

C

# ARIZONA ELECTRIC POWER COOPERATIVE, INC.

## TARIFF

**PERMANENT**

Effective Date: _____

Availability

Available to all cooperative associations which are or shall be all requirements Class A members 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 following rates and terms:

Demand Charge
$13.55 per kW of billing demand, plus

Energy Charge
$0.01608 per kWh used during billing period.

Billing Demand - The billing demand shall be that thirty minute integrated Class A member metered demand coincident at the hour of the AEPCO monthly peak. Contracts specifying demand levels and billing parameters are not included in this Class A member definition of billing demand and are billed separately.

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

Additional Charges - Service is also subject to the rates and charges stated in AEPCO's Regulatory Assets and Competition Transition Charge Supplemental Tariff. The demand and energy rates stated herein include no allowance for recovery of regulatory assets. Pursuant to Decision No. 62758, the regulatory assets and RAC have been assigned to Southwest Transmission Cooperative, Inc. AEPCO will pass through to its Class A members the RAC assessed by Southwest Transmission Cooperative, Inc.

Power Factor - Each member shall maintain power factor at the time of maximum demand as close to unity as possible. In the event the power factor measured at the time of the maximum demand is less than 90% lagging or leading, the maximum demand shall be adjusted for billing purposes by dividing the maximum measured demand by the measured power factor multiplied by .9. The provisions of the power factor adjustment will 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 also subject to adjustment for all federal, state and local government taxes or levies on such sales 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 will also be billed by AEPCO for charges it incurs for the transmission of 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.

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA | ) ) ) ) ) | DOCKET NO. RE-00000C-94-0165<br><br>**THE COOPERATIVES' FILING OF A CODE OF CONDUCT PURSUANT TO R14-2-1616 AND REQUEST FOR WAIVERS** |

The Cooperatives[1] submit this filing in compliance with R14-2-1616 and without waiver of the points raised in their Applications for Rehearing and appeals of Commission Orders concerning Retail Electric Competition including without limitation their Applications for Rehearing and appeals of Decision No. 61969.

## BACKGROUND

AEPCO is a non-profit generation and transmission cooperative formed in the early 1960s to supply and transmit at wholesale the power needs of its member distribution cooperatives.[2] It and most of its Member Distribution Cooperatives are Rural Utilities Service (RUS) borrowers. In order to meet FERC reciprocity and other requirements, AEPCO has filed an Open Access Transmission Tariff with SWRTA and adopted a Code of Conduct in relation to its provision of transmission and other ancillary services as defined by FERC.

[1] The Arizona Electric Power Cooperative, Inc. (AEPCO); Duncan Valley Electric Cooperative, Inc. (Duncan); Graham County Electric Cooperative, Inc. (Graham); Sulphur Springs Valley Electric Cooperative, Inc. (Sulphur); and Trico Electric Cooperative, Inc. (Trico). Duncan, Graham, Sulphur and Trico are collectively referred to as the "Member Distribution Cooperatives."

[2] AEPCO's fifth Class A Arizona member distribution cooperative is Mohave Electric Cooperative which is submitting its own filing.

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AEPCO does not provide service at retail. It makes only sales of power to its Member Distribution Cooperatives and others at wholesale pursuant to tariff or contract. The Member Distribution Cooperatives then supply that power at retail pursuant to their tariffs or contracts. The Cooperatives are separate corporate entities which are geographically and physically separated, supplying different services through separately owned facilities pursuant to separate tariff and contract policies and procedures. No cooperative exercises control over any other cooperative nor holds any equity shares in any other cooperative. Each cooperative employs its own staff although the Member Distribution Cooperatives pursuant to bylaw provisions do send representatives to the AEPCO board.

Thus, the Cooperatives are legally, functionally and physically disaggregated. They are not affiliates of each other as that term is normally defined. *See*, for example, the Affiliate Interest Rules, R14-2-801 *et seq.* which apply to investor owned not cooperative public service corporations.

AEPCO is in the process of restructuring. As applicable here and subject to RUS', this Commission's and others' approvals, Sierra Southwest Electric Power Cooperative Services, Inc. ("Sierra") has been formed. AEPCO is a Class B member of Sierra; the Member Distribution Cooperatives are Class A members of Sierra. Sierra has obtained a certificate of convenience and necessity as an ESP from this Commission. For the provision of any Competitive Services, however, it will maintain its own staff and physical facilities in Tucson separate from those AEPCO maintains in Benson or the Member Distribution Cooperatives maintain in other locations around the state.

Pursuant to A.R.S. § 10-2138, Sierra must seek approval from a cooperative prior to supplying electric generation service in the service territory of that cooperative. Pursuant to A.R.S. §§ 10-2057.A.4 and 10-2127.A.5, the Cooperatives are authorized to engage in joint

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marketing activities. To comply with both requirements and authorizations, Sierra and each member distribution cooperative will separately enter into a Joint Marketing Plan Agreement.

For the reasons discussed in this submission, the Cooperatives do not believe the Code of Conduct provisions of R14-2-1616 can or should apply to them. Because, however, AEPCO is a member of Sierra and the Member Distribution Cooperatives are members of Sierra, this submission is made in compliance with R14-2-1616.A. subject to the requested waivers

## CODES OF CONDUCT

AEPCO proposes the Code of Conduct attached as Exhibit A between it and Sierra. The Member Distribution Cooperatives propose the Code of Conduct attached as Exhibit B between each of them and Sierra. Although certain of the Rule's provisions do not seem to apply to the disaggregated cooperative structure previously discussed, the Cooperatives have in proposing these Codes attempted in good faith to apply the Rule's standards where relevant to their activities.

## REQUESTED WAIVERS

### As to the Cooperatives

AEPCO, the Member Distribution Cooperatives and Sierra are separate corporate entities, performing separate functions through separate staffs and facilities pursuant to separate tariffs and contracts. They are already disaggregated in wholesale, retail and competitive service delivery and unlike other integrated utilities subject to this Commission's jurisdiction have not previously provided services in a single corporate structure both at wholesale and retail. Thus, the concerns underlying the Code of Conduct requirements simply do not exist for the Cooperatives.

For example, AEPCO does not have detailed retail customer information which it could supply to Sierra. Wholesale and retail services have been and are provided by separate corporations pursuant to different tariffs approved by this Commission so the possibility of

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internal rate cross subsidization does not exist. Also, the Cooperatives do not have market power; it is estimated that they supply only about 3% of the state's power requirements.

Without comment on the need for Codes of Conduct generally,[3] the Cooperatives believe that these and other differences negate the need for Codes of Conduct as applied to them. Therefore, they request a general waiver of R14-2-1616.

**As to AEPCO/Sierra**

Because AEPCO is a member of Sierra, R14-2-1616.A seems to apply to AEPCO. However, AEPCO is not a "utility distribution company" and each of the subjects required to be addressed by the Code of Conduct in R14-2-1616.B relate to AEPCO's non-existent role as a UDC. In AEPCO's case, the two subsections of the Rule simply do not relate to each other. For that reason, AEPCO requests a Commission waiver or finding that the Rule does not apply to it.

**As to Sierra/the Member Distribution Cooperatives**

If the request for general waiver is not granted, the Member Distribution Cooperatives request a waiver of the specific requirement of R14-2-1616.B.4 and 6 which generally pertain to name issues and require that there be no "joint advertising, joint marketing, or joint sales" ("joint marketing") by each of them with Sierra. In support of this request, the Cooperatives note the following:

1. Pursuant to R14-2-1615.C, the Member Distribution Cooperatives are specifically authorized to supply both noncompetitive and competitive services within its territory. That provision of the Rule conflicts with the prohibition on joint marketing with Sierra. Because the cooperatives may supply both services, under the Rules their decision to supply Competitive Services in tandem with Sierra should not be restricted by another Rules' provision.

[3] The Cooperatives note again that no similar Code of Conduct provisions were adopted by the



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2. Joint marketing is specifically allowed and required by A.R.S. §§ 10-2127.A.5 and 10-2138;

3. Joint marketing will enable small rural electric cooperatives with few resources, no market power and limited staffing access to Arizona's competitive marketplace which they otherwise will not have;

4. Joint marketing will encourage development of a competitive electric generation market in Arizona by increasing the amount of competitors available to customers in the rural areas;

5. Joint marketing will provide rural electric cooperatives with the ability effectively to compete with larger marketing entities to replace Standard Offer sales lost to the competitive market, thereby keeping the cost of Standard Offer service lower in rural areas;

6. Joint marketing will ensure the continuation of electric service at reasonable prices to rural areas which have historically been unserved or underserved by competitive markets and profit making utilities; and

7. The Commission cannot constitutionally restrict the free speech of Affected Utilities and, especially, while not similarly restricting the speech of a new market entrant.

This specific request for waiver of R14-2-1616.B.6 is in addition to and not in lieu of the previous request for a general waiver of the Rules' requirements.

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Commission for Competitive Telecommunications Services. *See* R14-2-1101 *et seq.*



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## CONCLUSION

The Cooperatives request that the Commission grant the waivers as requested herein or, alternatively, approve the Codes of Conduct which are attached to this submission as Exhibits A and B.

RESPECTFULLY SUBMITTED this 4th day of February, 2000.

GALLAGHER & KENNEDY, P.A.

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Exhibit A

# Arizona Electric Power Cooperative, Inc., and Sierra Southwest Electric Power Cooperative Services, Inc.

## CODE OF CONDUCT

Arizona Electric Power Cooperative, Inc. (AEPCO) is a non-profit electric generation and transmission cooperative which makes only wholesale sales of electric energy to its Class A member-owners, among others. It does not provide retail service to end-use customers nor does it provide Distribution Service. Its Class A Members are non-profit rural electric distribution cooperatives which make sales of electricity at retail to their members and other patrons. Pursuant to A.A.C. R14-2-1615.C, distribution cooperatives may provide both Noncompetitive Services and Competitive Services within their distribution service territories.

Sierra Southwest Electric Power Cooperative Services, Inc. ("Sierra") is also a non-profit cooperative and holds a CC&N as an Electric Service Provider to provide certain Competitive Services (among them, retail electric sales) in Arizona. Its members include the electric distribution cooperatives (as Class A Members), AEPCO and other utilities (as Class B members) as well as its retail customers (as Class C Members).

Pursuant to the bylaws of AEPCO and Sierra, each distribution cooperative that is a Class A Member of AEPCO and/or of Sierra is represented on the Board of Directors of AEPCO and/or Sierra as are other classes of membership. However, each cooperative is a corporate entity entirely separate from each other cooperative. No cooperative holds any equity shares of any other cooperative nor does any cooperative exercise control over any other cooperative. Therefore, they are not "affiliates" of each other.

A.A.C. R14-2-1616 ("the Rule") requires: "Each Affected Utility that is an electric cooperative, that plans to offer Noncompetitive Services, and that is a member of any electric cooperative that plans to offer Competitive Services shall also submit a Code of Conduct to prevent anti-competitive activities." AEPCO does not provide Standard Offer Service, it only makes wholesale sales. While AEPCO is a member of Sierra which provides Competitive Services, AEPCO is not a "Utility Distribution Company" to which R14-2-1616.B relates. Although AEPCO does not believe the Rule specifically applies to it, AEPCO supplies this Code of Conduct to comply with the Rules and to describe and govern certain conduct concerning AEPCO and Sierra. (AEPCO also provides transmission and other ancillary services deemed non-competitive by FERC and does so in conformance with FERC's requirements for a code of conduct and separation of functions. Provision of those services is not intended to be included within this Code of Conduct.)

### 1. DEFINITIONS

All capitalized terms used and not defined herein shall have the respective meanings set forth in A.A.C. R14-2-1601.

"AEPCO" shall mean the Arizona AEPCO Electric Power Cooperative, Inc..

"Class A Members" shall mean AEPCO's Class A Members which serve retail customers in Arizona and includes: Duncan Valley Electric Cooperative, Inc. (DVEC), Graham County Electric Cooperative, Inc. (GCEC), Mohave Electric Cooperative, Inc. (MEC ), Sulphur Springs Valley Electric Cooperative Inc. (SSVEC) and TRICO Electric Cooperative, Inc. (TRICO).

"Sierra" shall mean Sierra Southwest Electric Power Cooperative Services, Inc.

"Rule" shall mean A.A.C. R14-2-1616. Code of Conduct

"RUS" shall mean the Rural Utilities Service, an agency of the United States Department of Agriculture.

"Personnel" shall mean a cooperative's employee, authorized agent or representative, leased employee or other worker provided to the cooperative under contract by another cooperative or third party.

## 2. APPLICABILITY OF CODE OF CONDUCT

2.1 This Code of Conduct shall apply to the conduct specified between AEPCO and Sierra. All Personnel shall conduct their activities in compliance with its requirements.

2.2 Failure to conduct activities in compliance with this Code of Conduct will subject the employee or agent to disciplinary or other actions in accordance with policies established by AEPCO or Sierra.

2.3 Copies of the Code of Conduct and associated policies and procedures shall be provided to Personnel and authorized agents and training on its provisions shall be provided.

## 3. CUSTOMER TELEPHONE CALLS

Telephone numbers used by AEPCO shall be different than those used for Sierra's competitive activities.

## 4. PROHIBITION ON SUGGESTION OF UTILITY ADVANTAGE

AEPCO Personnel shall not state that a consumer who purchases competitive services from Sierra will receive any preferential treatment in the provision of Noncompetitive Services from an AEPCO Class A Member.

## 5. ACCOUNTING FOR COSTS

5.1. AEPCO and Sierra shall keep separate books and records. All records of each company shall be kept in accordance with the RUS Uniform System of Accounts and/or Generally Accepted Accounting Principles.

5.2. AEPCO shall develop and follow a cost allocation methodology to account for and bill transactions between AEPCO and Sierra based on the following:

a. To the extent practicable, costs will be classified on a direct cost basis for each service or product provided.

b. Indirect costs will be charged on a fully allocated basis as a cost for employee and management services or for any other services.

c. All direct and indirect costs for services and products will be traceable on the accounting records by account prescribed by the RUS Uniform System of Accounts.

d. Cost allocations shall include, without limitation:
   1. employee salaries and benefits;
   2. purchased materials and services;
   3. costs associated with office buildings and office furniture including computer equipment software programs and systems;
   4. management services;
   5. administrative and general overheads; and
   6. taxes imposed by Federal, State or other political subdivisions.

## 6. SEPARATION REQUIREMENTS

6.1. AEPCO shall be a separate corporate entity from Sierra.

6.2. AEPCO shall maintain its offices in a location geographically separate from Sierra's Competitive Services sales offices, telephones and Personnel.

6.3. AEPCO may contract for services and Personnel from Sierra through a written staffing agreement.

6.4. Any telecommunications, computer and information systems shared between AEPCO and Sierra shall be operated with appropriate security devices and procedures to protect against any disclosure of information in a manner inconsistent with this Code of Conduct.

6.5. AEPCO shall ensure that Sierra Personnel who provide staffing services to AEPCO shall do so in conformance with this Code of Conduct.

6.6 In accordance with the bylaws of AEPCO and Sierra, an officer or director of AEPCO may also serve as an officer or director of Sierra. Joint officers or directors shall not provide Standard Offer customer information obtained from a Class A Member to Sierra for its provision of competitive services without the customer's consent.

## 7. TRANSFERS OF GOODS AND SERVICES

All transfers of nontariffed goods and services from AEPCO to Sierra shall be priced to recover, at least, AEPCO's cost and shall be accounted for in accordance with Section 5 above.

## 8. TRANSFERS OF ASSETS

Any transfer of assets from AEPCO to Sierra shall be conducted in accordance with RUS requirements and generally accepted accounting principles.

## 9. VIOLATIONS

If filed with the Commission, complaints concerning alleged violations of the Code of Conduct shall be processed under the procedures established in A.A.C. R14-2-212.

Exhibit B

# ARIZONA ELECTRIC COOPERATIVES

# CODE OF CONDUCT

## INTRODUCTION

Pursuant to A.A.C.R14-2-1616A, each Affected Utility, including an electric cooperative, is required to establish a Code of Conduct. The cited rule states: "Each Affected Utility that is an electric cooperative that plans to offer Noncompetitive Services, and that is a member of any electric cooperative that plans to offer Competitive Services shall also submit a Code of Conduct to prevent anti-competitive activities". The Cooperatives propose this Code of Conduct to meet the requirements of the Rules.

## DEFINITIONS

"Arizona Electric Cooperatives" or "Cooperatives" means the following organizations: Sierra Southwest Electric Power Services Cooperative, Inc. (Sierra) and the Member Distribution Cooperatives.

"Competitive Services" means those services described in A.A.C. R14-2-1601(7).

"Commission" means the Arizona Corporation Commission.

"Electric Competition Rules" or "Rules" means A.A.C. R14-2-1601 et seq., as set forth in Decision No. 61969 dated September 29,1999.

"Distribution Services" means those services described in A.A.C. R14-2-1601 (14).

"Electric Service Provider" or "ESP" means a provider of Competitive Services as defined in A.A.C. R14-2-1601 (15).

"Member Distribution Cooperatives" mean Duncan Valley Electric Cooperative, Inc. (Duncan); Graham County Electric Cooperative, Inc. (Graham), Mohave Electric Cooperative, Inc. (Mohave), Sulphur Springs Valley Electric Cooperative, Inc., (Sulphur), and Trico Electric Cooperative, Inc. (Trico).

"Noncompetitive Services" means those services described in A.A.C. R14-2-1601(29).

CODE OF CONDUCT PROVISIONS

A. General

1. All employees and authorized agents of the Cooperatives shall conduct their activities in compliance with the requirements of this Code of Conduct.
2. Failure to conduct activities in compliance with this Code of Conduct will subject the employee or agent to disciplinary or other actions in accordance with the policies of the individual Cooperative.
3. Copies of the Code of Conduct and associated policies and procedures shall be provided to employees and authorized agents of the Cooperatives.
4. Training on the provisions of the Code of Conduct and its implementation shall be provided to the employees of the Member Distribution Cooperatives and authorized agents likely to be engaged in activities subject to the Code of Conduct.

B. Financial Matters

1. Financial Separation – Should a Member Distribution Cooperative elect to offer Competitive Services outside its distribution service territory, such services shall be provided only through a separate corporate affiliate in accordance with the Rules. The Member Distribution Cooperative and its affiliate shall keep separate books, records and accounts. The Member Distribution Cooperative shall not subsidize Competitive Services through rates and charges for Non-Competitive Services.

2. Accounting for Costs – Member Distribution Cooperatives and Sierra are separate corporate entities and each shall keep and maintain separate books, records and accounts. All books, records and accounts shall be maintained in accordance with the RUS Uniform System of Accounts and accounting standards.
3. Cost Allocation – In all transactions between a Member Distribution Cooperative and Sierra, each shall develop and follow a cost allocation methodology to account for and bill transactions between them based on the following:
   a. To the extent practicable, costs will be collected and classified on a direct cost basis for each service or product provided.
   b. Indirect costs will be charged on a fully allocated basis as a cost for employee and management services or for any other services.
   c. All direct and indirect costs for services and products will be traceable on the accounting records by account prescribed by the RUS Uniform System of Accounts.
   d. Cost allocations shall include, without limitation, all purchased materials and services.

C. Separation Requirements

1. Each Member Distribution Cooperative shall maintain its offices in a location geographically separate from Sierra's sales offices, telephones and personnel.
2. Any telecommunications, computer and information systems shared by a Member Distribution Cooperative, Sierra or a competitive affiliate shall be operated with appropriate security devices and procedures to protect against any disclosure of information in a manner inconsistent with this Code of Conduct.

D. Use of Confidential Customer Information

1. A Cooperative shall not provide confidential customer information obtained in the provision of Noncompetitive Services to any third party without the customer's written authorization. Such information may be provided only to the extent specifically authorized.
2. A Cooperative shall inform any third party seeking such confidential customer information that the information may be released only after the Cooperative receives the customer's written authorization.
3. A Member Distribution Cooperative, shall provide, with the customer's written authorization, confidential customer information obtained in the provision of Non-Competitive Services to an ESP in the same manner and form as it would provide such information to Sierra.

E. Joint Employment

1. Each Cooperative is a separate corporate entity and shall maintain its own staff.
2. Should a Member Distribution Cooperative elect to provide Competitive Services outside its distribution service territory through a competitive affiliate, such competitive affiliate shall provide and employ its own staff.
3. Member Distribution Cooperatives, Sierra and any separate competitive affiliate may jointly employ officers and directors in accordance with applicable bylaw provisions. Joint officers and directors, however, shall not provide customer information obtained from a Cooperative supplying Noncompetitive Services to any Cooperative supplying Competitive Services without the customer's consent.

F. Non-Preferential Treatment

1. A Member Distribution Cooperative that enters into a joint marketing agreement with Sierra or participates in the formation of a competitive corporate affiliate shall, together with Sierra or such corporate affiliate, comply with this Code of Conduct.
2. Member Distribution Cooperatives shall apply tariffs in the same manner to similarly situated persons. If a tariff provision allows for discretion in its application, the Member Distribution Cooperative shall apply that provision in a non-discriminatory manner.
3. A Member Distribution Cooperative shall process similar requests for Noncompetitive Services and for Competitive Services, if applicable, in the same manner and according to the order in which received.
4. A Member Distribution Cooperative shall provide information concerning its Distribution Services (including information about available distribution capability, distribution access and curtailments) to ESPs, Sierra and any Competitive Service affiliate on a non-discriminatory basis.

G. Prohibition on Suggestion of Utility Advantage

1. Member Distribution Cooperatives shall not state in any advertising, promotional materials or sales efforts that a consumer who purchases Standard Offer Service or other Non-Competitive Service from the Member Distribution Cooperative will receive any better service from the Member Distribution Cooperative as a result of purchasing Competitive Services from Sierra or any competitive affiliate.
2. A Member Distribution Cooperative shall not require that a consumer purchase any Competitive Service from the Member Distribution Cooperative or Sierra as a condition to providing Noncompetitive Services.

H. Joint Advertising, Marketing, and Sales

1. Pursuant to A.R.S. §§ 10-2057.A.4, 10-2127.A.5 and 10-2138 a Member Distribution Cooperative and Sierra may engage in joint advertising, joint marketing and joint sales activities.
2. Joint Advertising, Joint Marketing, and Joint Sales activities may be performed only in accordance with a written Joint Marketing Plan entered into between a Member Distribution Cooperative and Sierra.
3. Any joint advertising, joint marketing and joint sales activities shall be conducted in conformance with this Code of Conduct.

I. Code of Conduct Violations – If filed with the Commission, complaints concerning alleged violations of the Code of Conduct shall be processed under the procedures established in A.A.C.R14-2-212.