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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN

Docket No. E-01773A-09-0472

JOINT REQUEST FOR CONTRACT/AMENDMENTS APPROVALS AND REVISED RATES REQUEST

GALLAGHER & KENNEDY, P.A.
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The Arizona Electric Power Cooperative, Inc. ("AEPCO") and Intervenors TRICO Electric Cooperative, Inc. ("TRICO"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Mohave Electric Cooperative, Inc. ("MEC") (collectively, the "Cooperatives") submit this Joint Request for Arizona Corporation Commission ("Commission") approval of (1) a new Partial-Requirements Capacity and Energy Agreement between AEPCO and TRICO and (2) Amendments to the existing Partial-Requirements Agreements between AEPCO and SSVEC and AEPCO and MEC.

In support of their Joint Request, the Cooperatives state as follows:

1. AEPCO is an Arizona non-profit electric generation cooperative which supplies all or most of the power and energy needs of its five Arizona Class A member distribution cooperatives. Currently, AEPCO's Arizona all-requirements members are the Duncan Valley Electric Cooperative ("DVEC"), Graham County Electric Cooperative ("GCEC") and TRICO. Under the all-requirements relationship, these Class A members are obligated to purchase and,

correspondingly, AEPCO is obligated to plan for and supply, all of the power and energy needs which these distribution cooperatives require for their retail members.

2. MEC and SSVEC are AEPCO's partial-requirements Class A members. In Decision No. 70105, the Commission approved the partial-requirements agreement between AEPCO and SSVEC (the "SSVEC Partial"). Previously, in Decision No. 63868 dated July 25, 2001, the Commission approved the Partial-Requirements Capacity and Energy Agreement between AEPCO and MEC (the "MEC Partial") as part of AEPCO's restructuring. Under these partial-requirements relationships, MEC and SSVEC commit to pay for a fixed amount of capacity and may purchase the associated energy from AEPCO and AEPCO commits to supply such capacity and energy. MEC and SSVEC then secure from sources of their choosing any additional power requirements necessary to meet the power and energy needs of their retail members.

3. One of the primary objectives of the AEPCO restructuring was to provide its Class A members with more flexible purchased power arrangements. The Conversion Agreement executed as part of the restructuring provides that any of the members have the right to convert from an all- to a partial-requirements status as SSVEC did in 2008 and as MEC did as part of AEPCO's restructuring in 2001.

4. As discussed at pages 5-6 of Mr. Pierson's Supplemental Direct Testimony, TRICO has elected to convert its Class A member relationship with AEPCO from an all- to a partial-requirements relationship. Attached hereto as Exhibit A is the Partial-Requirements Capacity and Energy Agreement between AEPCO and TRICO (the "TRICO Partial").

5. AEPCO and its Class A members have recently concluded lengthy discussions that resulted in agreed upon changes to cost allocation and rate design in order to resolve

outstanding disputes with AEPCO and among its Class A members, thereby substantially reducing the issues that would otherwise be raised in AEPCO's pending rate case. Those agreements are described in AEPCO's rate application and amended rate application filings made on October 1, 2009 and April 20, 2010 in this docket. The agreements benefit the Parties and the public by providing for a fair, equitable and repeatable allocation of costs and revenues at issue between the PRMs and ARMs based on principles of cost causation, while providing AEPCO with fair and reasonable recovery of its revenue requirements and sufficient operating margins.

6. The revenue, rate design and cost allocation agreements reached with AEPCO and among its Class A members are reflected in the TRICO Partial, as well as the Third Amendment to the MEC Partial ("MEC Partial Amendment"), attached hereto as Exhibit B and the First Amendment to the SSVEC Partial ("SSVEC Partial Amendment") attached hereto as Exhibit C.

7. AEPCO's Board, which is comprised of elected representatives of its all- and partial-requirements members, has reviewed, approved and supports the TRICO Partial, the MEC Partial Amendment and the SSVEC Partial Amendment. The Cooperatives' Boards of Directors have also individually reviewed, approved and support the TRICO Partial, the MEC Partial Amendment and the SSVEC Partial Amendment. Approvals of the Commission and the Rural Utilities Service ("RUS") are conditions precedent to the TRICO Partial, the MEC Partial Amendment and the SSVEC Partial Amendment becoming effective.

8. The AEPCO Board instructed AEPCO's management to secure necessary regulatory consents to authorize the implementation of the TRICO Partial, the MEC Partial Amendment and the SSVEC Partial Amendment.

9. In that regard, this Joint Request is being filed with the Commission and AEPCO is in the process of making the required filings to secure RUS approval.

10. Attached as Exhibit D is a Summary of Revised Proposed Rates (right-hand column) which AEPCO now requests be approved for its Arizona All-Requirements Members (DVEC and GCEC) and for its Partial-Requirements Members (TRICO, MEC and SSVEC) as part of its rate application filed in this docket. The rates requested in Exhibit D for TRICO and AEPCO's All-Requirements Members (DVEC and GCEC) have been adjusted from those presented in AEPCO's April 20, 2010 amended filing to reflect the conversion of TRICO to a Partial Requirements Member. The rates stated in Exhibit D for MEC and SSVEC are the same as those filed April 20, 2010 as those rates are not affected by TRICO's conversion to a Partial Requirements Member.

11. AEPCO's overall rate <u>decrease</u> request of .06% on an adjusted test year basis has not changed. The rates requested in Exhibit D result in an estimated 1.1% decrease in revenues from DVEC, a 1% revenue decrease from GCEC and a 5.1% revenue decrease from TRICO as compared to AEPCO's adjusted test year revenues. As reflected in AEPCO's April 20, 2010 amended filing, revenues from MEC and from SSVEC will increase an estimated 3.08% and 1.32%, respectively, as compared to AEPCO's adjusted test year revenue.

12. AEPCO shortly will file an Exhibit GLG-4, sponsored by Mr. Goble, which will state revised requested PPFAC bases.

WHEREFORE, having stated their Joint Request, Applicants request that the Commission as part of its Decision in the pending rate proceeding in this docket approve:

1. The TRICO Partial Agreement, attached as Exhibit A;

2. The Third Amendment to the MEC Partial, attached as Exhibit B;

3. The First Amendment to the SSVEC Partial, attached as Exhibit C; and

4. The rates stated in the Revised Proposed Rates column of Exhibit D for TRICO, DVEC, GCEC, MEC and SSVEC.

RESPECTFULLY SUBMITTED this 2nd day of June, 2010.

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Original and 13 copies filed this 2nd day of June, 2010, with:

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Copies of the foregoing delivered this 2nd day of June, 2010, to:

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EXHIBIT A

PARTIAL REQUIREMENTS

CAPACITY AND ENERGY AGREEMENT

BETWEEN

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

AND

TRICO ELECTRIC COOPERATIVE, INC.

TABLE OF CONTENTS

LIST OF SCHEDULES AND ATTACHMENTS

Schedules

Schedule A	Rates
Schedule B	Minimum and Maximum Energy Takes

Appendices

Amended and Restated Appendix A	Definitions as Amended and Restated as of the Agreement Date

PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

PARTIES

The Parties to this PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT (Agreement or TRICO Partial Requirements Capacity and Energy Agreement) are Trico Electric Cooperative, Inc., a non-profit corporation organized under the laws of the State of Arizona (Member or TRICO), 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 February 15, 1962, as amended, (Existing Wholesale Power Contract).

B. AEPCO's membership consists of Class A Members, Class B Members, Class C Members and Class D Members. AEPCO's Class A Members consist of Anza Electric Cooperative, Inc. (ANZA); 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 Member, which members are referred to individually and collectively in this Agreement as "Class A Member(s)." The sole Class B Member of AEPCO is the Salt River Project Agricultural Improvement and Power District. The sole Class D Member of AEPCO is Valley Electric Association. The Class A, B, C and D Members are referred to in this Agreement collectively as "Members." The Class A Members, except MEC, SSVEC and Member, are referred to in this Agreement collectively as "All Requirements Members," and individually as an "All Requirements Member." Member, SSVEC and MEC are referred to in this Agreement collectively as "Partial Requirements Members," and individually as a "Partial 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 as amended as of the Approval Date, concerning the pooling and operation of certain Resources. Further, TRANSCO and the Member may also contemporaneously execute other transmission agreements between them.

D. As part of the overall restructuring of its system, AEPCO transferred its Transmission Business substantially as an entirety to TRANSCO. AEPCO also transferred 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 was accomplished pursuant to the provisions of the Restructuring Agreement, dated October 11, 2000, entered into by and among AEPCO, TRANSCO and CSP (Restructuring Agreement), and the Member Agreement, dated July 2, 2001, entered into by and among AEPCO, TRANSCO, CSP and the Class A Members (Member Agreement). Also, as part of the restructuring, AEPCO and MEC entered into a Partial Requirements Capacity and Energy Agreement, dated August 1, 2001 (MEC Partial Requirements Capacity and Energy Agreement), and ANZA, DVEC, GCEC, SSVEC, TRICO and AEPCO entered into the Conversion Agreement, dated August 1, 2001, (Conversion Agreement). Subsequent to the restructuring, SSVEC exercised its rights under the Conversion Agreement and AEPCO and SSVEC entered into a Partial Requirements Capacity and Energy Agreement, effective as of January 1, 2008. TRICO gave notice of its intent to exercise its right under the Conversion Agreement on November 20, 2009, to become a Partial Requirements Member on one year's notice.

E. AEPCO owns and operates electric generation facilities and assets and has rights to electric energy and capacity under various purchase agreements (collectively, the "AEPCO 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 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 August 3, 2009, made by and among AEPCO and RUS and CFC as amended and consolidated, supplemented 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, the MEC Partial Requirements Capacity and

Energy Agreement, the SSVEC Partial Requirements Capacity and Energy Agreement 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 AEPCO 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 All Requirements Class A Members, including the Member, and the partial requirements of MEC, SSVEC and other wholesale customers of AEPCO. Commencing on the Approval Date, the servicing of the current and future electric loads of AEPCO, CSP, MEC, SSVEC and the Member will be managed pursuant to this Agreement; the Transmission Agreement between TRANSCO and Member, the Transmission Agreement between TRANSCO and MEC, and the Transmission Agreement between TRANSCO and SSVEC; certain other agreements for transmission service between TRANSCO, the All Requirements Members, the Partial Requirements Members and AEPCO, pertaining to the electric loads of the All Requirements Members; and other arrangements for transmission service between AEPCO and TRANSCO pertaining to the electric loads of other wholesale customers of AEPCO.

K. The Member has determined that its interests and the interests of its consumers will be best served by electing to become a Partial Requirements Member pursuant to the Conversion Agreement and 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 defined herein shall have the meaning set forth in this Section 1, and are defined solely for use with this Agreement, including Rate Schedule A and Schedule B hereto. All capitalized terms used and not defined herein shall have the respective meanings as set forth in Amended and Restated Appendix A, dated May 11, 2010 attached hereto.

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, the MEC Partial Requirements Capacity and Energy Agreement, the SSVEC Partial Requirements Capacity and Energy 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) include 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, determined in accordance with Accounting Requirements.

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

1.5 "Approval Date" shall mean the first day of the month, no earlier than December 1, 2010, following the latter of 1) the date upon which the TRICO Transmission Agreement and the TRICO PRC&EA shall have been approved by the RUS, 2) the date upon which the TRICO PRC&EA shall have been approved by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

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

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

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

1.9 "MEC Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and MEC.

1.10 "MEC Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and MEC.

1.11 "Member Billing Demand" shall mean, as to Member, the demand of Member in kW integrated over the thirty (30) minute period purchased by Member from AEPCO pursuant to this TRICO Partial Requirements Capacity and Energy Agreement, occurring coincident in time with the AEPCO's Member Peak Demand, which Member Billing Demand consists of the demands of TRICO AEPCO Load and TRICO AEPCO Sales.

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

1.13 "O&M Charge" shall mean the charge computed in accordance with 5.3 herein which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

1.14 "PGR Purchase Agreement" shall mean the Power Purchase Agreement between Panda Gila River, L.P., and AEPCO, dated April 15, 2003, as amended.

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

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

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

1.18 "SSVEC Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and SSVEC.

1.19 "SSVEC Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and SSVEC.

1.20 "TRICO 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 TRICO (or served from line extensions therefrom) for which TRICO purchases capacity and energy pursuant to the TRICO Partial Requirements Capacity and Energy Agreement, but shall not include TRICO Wheeling Load. Such demand and energy requirements are included within TRICO Metered kW and TRICO Metered kWh. The demand component of TRICO AEPCO Load numerically consists of the coincident aggregate, at a specific time, of: (i) TRICO Metered kW; less (ii) kW of TRICO Wheeling Load; less (iii) kW of Member JMP Load of TRICO; less (iv) kW of CSP JMP Load of TRICO; (v) less kW of TRICO Internal Load. The energy component of TRICO AEPCO Load numerically consists of the aggregate during a specific time interval of: (i) TRICO Metered kWh; less (ii) kWh of TRICO Wheeling Load; less (iii) kWh of Member JMP Load of TRICO; less (iv) kWh of CSP JMP Load of TRICO; less, (v) kWh of TRICO Internal Load.

1.21 "TRICO 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 TRICO to wholesale buyers or to end use loads which are external to Member's Distribution Service Area of TRICO for which TRICO purchases capacity and energy pursuant to the TRICO Partial Requirements Capacity and Energy Agreement. The demand and energy requirements of TRICO AEPCO Sales shall be metered (or determined) as agreed between TRICO and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery.

1.22 "TRICO Metered kW" shall mean the demand in kW received at the Delivery Points of TRICO 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, TRICO Metered kW consists of the integrated demands of: (i) TRICO AEPCO Load; (ii) TRICO Wheeling Load; (iii) Member JMP Load of TRICO; (iv) CSP JMP Load of TRICO; and (v) TRICO Internal Load.

1.23 "TRICO Metered kWh" shall mean the total energy in kWh delivered to the Delivery Points of TRICO 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, TRICO Metered kWh consists of the kWh of energy, as measured at the Delivery Points, consumed by: (i) TRICO AEPCO Load; (ii) TRICO Wheeling Load; (iii) Member JMP Load of TRICO; (iv) CSP JMP Load of TRICO; and, (v) TRICO Internal Load.

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 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.

2.2 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 charges and on the terms and conditions set forth herein and in Rate Schedule A. The Member shall make all payments of charges and energy charges for capacity and energy provided for under this Agreement, including without limitation, rates and 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) days and within five (5) 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) days thereafter. If AEPCO agrees with Member, it shall amend the bill to reflect the correction within ten (10) 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 (such services, collectively referred to as "Planning Services") for the Member, except pursuant to a separate written agreement for such Planning Services executed by the Member and AEPCO and paid for by Member. 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 any Planning Services whatsoever shall be the sole responsibility of Member and not of 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 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 this Section 3.3.1, 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 Member 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 by AEPCO, Member may within fifteen (15) business days thereafter 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 Resource Modification, AEPCO shall submit to the Member a document with respect to any proposed Resource Modification (Proposal and Analysis) containing: (i) the reasons therefore; (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 charges 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 Generating 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) day of the following calendar month. Member shall pay AEPCO the total amount of such bill by the later of (a) the twentieth (20th) day of the month that the bill is sent or (b) ten (10) 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, charges, 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 5.6 hereof. All such rates, charges 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 ACP 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 Schedule B 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 monthly energy charges 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 as 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 charges for electric energy and capacity provided hereunder, under any Partial Requirements Capacity and Energy Agreement with any other Class A Member and under the Existing Wholesale Power Contracts with AEPCO's All Requirements Members. If such rates or charges 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 charges with the effective date thereof, and the basis upon which the rates or charges are proposed to be adjusted and set. The Member agrees that the rates and charges 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 charges pursuant to such revised rates and charges; provided that no such revised rates or charges shall be effective if they have been disapproved in writing by the Administrator. AEPCO shall design and set future rates and charges 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 charges 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 Rate. The Parties agree that the rates, charges, rate methodology, and 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 charges 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 charges 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 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 among the AEPCO 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, charges 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 and 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 therefore 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. <u>JOINT MARKETING AGREEMENTS</u>:

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. <u>STRANDED COST RECOVERY</u>:

8.1 <u>Stranded Cost Recovery</u>. 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 <u>Recovery of Stranded Costs by AEPCO</u>. 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:

10.1 The Class A Members of Generating Cooperative (Class A Members), including Member, shall have an opportunity to make recommendations to the Operations and Construction Committee (OCC) and the Finance and Audit Committee (FAC) of the Board of Directors of Generating Cooperative (AEPCO) and to the AEPCO Board as described below on any matters that relate to the service and cost of the service provided by AEPCO to Member through the representative of each on a committee (Representative) herein designated as the Operations Review Committee (Committee).

10.2 The Committee shall consist of one authorized Representative from each Class A Member and a Representative designated by AEPCO, who shall serve as Chairperson of the Committee. Each Class A Member shall designate as its Representative an employee of such Class A Member with experience in the areas in which the Committee will function and AEPCO shall designate the Chairperson, who shall be an AEPCO employee.

10.3 Each Class A Member shall evidence the appointment of its Representative by written notice to the other Class A Members and AEPCO, and by similar notice, any Class A Member or AEPCO may change its Representative on the Committee at any time. The list of Committee Representatives will be updated by the Chairperson and distributed to each of the Class A Members with appropriate contact information as necessary to keep the list current as to representation on the Committee.

10.4 Each Class A Member shall be entitled to one vote through its Representative on matters that come before the Committee. In the absence of unanimous consent, the various positions of the Representatives shall be compiled, referred and communicated to the OCC and or FAC by those Representatives electing to do so.

10.5 The Committee shall meet in person or telephonically quarterly except as otherwise determined by the Committee, but in no event less frequently than annually. The Representatives shall determine the agenda of the Committee and have access to all information related to the resources used by AEPCO to provide service.

10.6 Prior to the beginning of each calendar year, and as may be required during any such calendar year, an agenda for the Committee meeting will be solicited from the Representatives and the Committee will receive, consider and review all information requested by the Committee including but not limited to the Apache Station Operations and Maintenance Budget, Capital Budget and Construction Work Plans, A & G expenses proposed by AEPCO management, load forecasts, financial forecasts, cash flow forecasts, rate filings and forecasts, and review variances, updates and amendments thereto and such other operations data as may be requested. Following consideration thereof by the Committee, the Chairperson will promptly report such recommendations concerning any issues considered together with alternatives raised by a Representative to either the OCC or the FAC, as appropriate. The Representatives may make reports through the AEPCO Director for the Member they represent on the positions they sponsor if they differ from the Committee recommendation report to the OCC or the FAC. Such reports to the OCC and the FAC given by the Chairman and the sponsoring Director(s) shall present all alternatives considered by the Committee in addition to the recommendations of the Committee. Representatives of the Committee may assist in the presentation by their Director(s) of alternatives considered by the Committee for the Board's review in making the final Board decision.

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 Members' 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 therefore), 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 1.25 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 30% 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 first is 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) 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 Approval Date and, unless terminated by AEPCO in accordance with Section 14.1.2, shall remain in effect until December 31, 2035, unless extended further pursuant to Sections 3.3 and 3.4 hereof by the written agreement, consent or notice of Member given pursuant to Section 3 hereof. After December 31, 2035 (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 AEPCO Resources shall be effective unless: (i) in writing; (ii) executed by the Parties; (iii) approved by AEPCO and all Class A Members; and (iv) 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, Schedule B and Appendix A 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 Chief Executive Officer
Fax: (520) 586-5576 or 5402

If to Member: Trico Electric Cooperative, Inc.
8600 West Tangerine Road
Marana, Arizona 85658
Attention: Chief Executive Officer/General Manager
Fax: (520) 744-2329

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:

(i) 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.

(ii) 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, by-laws 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 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 book, record, 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 <u>Third Party Beneficiaries</u>. 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 <u>Obligations of RUS</u>. 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 <u>Validity of Agreement</u>. 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 <u>Headings</u>. 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 <u>Waiver of Trial by Jury</u>. 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 through any appeal, 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 Agreement Date, the terms of such AEPCO Loan Contract, AEPCO Note, loan or security instrument or the applicable regulation in effect on the Agreement 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 date set forth below.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

By: Donald W. Kimball

Name: Donald W. Kimball

Title: Executive Vice President and Chief Executive Officer

Date: 5/11/10

ATTEST:

By: Gary G. Grim

Name: Gary G. Grim

Title: Senior Vice President and Chief Operating Officer

Date: 5/11/10

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SIGNATURE PAGE FOR PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT BETWEEN AEPCO AND TRICO

TRICO ELECTRIC COOPERATIVE, INC.

By: George P. Davies
Name George P. Davies
Title: President
Date: May 12, 2010

ATTEST:

By: Vincent Nitido
Name: Vincent Nitido
Title: Chief Executive Officer and General Manager
Date: May 12, 2010

APPENDIX A

AMENDED AND RESTATED: DEFINITIONS
DATED May 11, 2010

1. These Definitions shall have the respective meanings set forth herein for use in the following agreements and their exhibits and schedules (unless the context in which the term is used in a particular agreement clearly requires otherwise):

    1. MEC Partial Requirements Capacity and Energy Agreement;
    2. SSVEC Partial Requirements Capacity and Energy Agreement;
    3. TRICO Partial Requirements Capacity and Energy Agreement;
    4. Resource Integration Agreement;
    5. SSVEC Transmission Agreement;
    6. MEC Transmission Agreement;
    7. TRICO Transmission Agreement;
    8. Network Service Agreement;
    9. Member Agreement between AEPCO, SWTC, Sierra and ANZA, DVEC, GCEC, MEC, SSVEC and TRICO.

2. These Definitions shall not be amended or modified without advance notice, review and approval by all parties to any of the agreements listed above, and RUS (as hereinafter defined), which remain executory, and after providing to all parties in advance a listing of any such agreements in which a proposed amended or modified defined term is contained.

3. The following shall be used in interpreting these Definitions and the agreements listed above:

    3.1 Unless otherwise required by the context in which any term appears:

    (a) Capitalized terms used in any agreement listed above shall have the meanings specified in this Appendix A or, if used solely within an Agreement, as set forth in such agreement.

    (b) The singular shall include the plural and the masculine shall include the feminine and neuter.

    (c) References to "Articles," "Sections," "Schedules," "Appendices" or "Exhibits" shall be to articles, sections, schedules, appendices, or exhibits of the agreement(s) specified, and references to paragraphs shall be to separate paragraphs of the section or subsection in which the reference occurs.

    (d) The words "herein," "hereof", "hereinbelow" and "hereunder" shall refer to an agreement, specified as a whole and not to any particular section or subsection of such agreement; the words "include," "includes" or "including" shall mean "including, but not limited to"; and the words "best effort(s)" shall mean a level of effort which, in the exercise of reasonable judgment in the light of facts known at the time a decision is made, can

be expected to accomplish the desired result at a reasonable cost, consistent with Prudent Utility Practice (as hereinafter defined).

(e) Except where the context otherwise indicates, the term "day" shall mean a calendar day, and whenever an event is to be performed by a particular date, or a period ends on a particular date, and the date in question falls on a weekend, a legal holiday in the State of Arizona, or a day when the relevant cooperative is not open for business, the event shall be performed, or the period shall end, on the next succeeding business day.

(f) All accounting terms not specifically defined herein or by specified Accounting Requirements (as hereinafter defined) shall be construed in accordance with Generally Accepted Accounting Principles in the United States of America, consistently applied.

3.2 All references herein to the term "cooperative" shall be to AEPCO, TRANSCO, CSP or a Member (as hereinafter defined) cooperative as appropriate from the context in an agreement.

3.3 All references to a particular entity shall include such entity's successor and permitted assigns.

3.4 All references herein to any agreement, including its schedules, exhibits and appendices, shall be to such agreement as amended, supplemented or modified.

3.5 All references herein to any Law (as hereinafter defined) shall be to such Law as amended, supplemented, modified or replaced.

3.6 The titles of the articles and sections of the agreements have been inserted as a matter of convenience of reference only and shall not control or affect the meaning or construction of any of the terms or provisions thereof.

3.7 The parties have agreed to the wording of the agreements, and none of the provisions thereof shall be construed against one party on the ground that any party is the author of such agreement or any part thereof.

3.8 In any defined term which begins with the word "PRM*," the word PRM* may be replaced with the name of a Partial Requirements Member. When the name of a Partial Requirements Member is substituted, the definition remains the same but is applicable only to the named Partial Requirements Member. For example, "'PRM* Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load." If MEC is substituted, "'MEC Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of MEC to MEC AEPCO Load."

"AC" shall mean Allocated Capacity.

"ACC" shall mean Arizona Corporation Commission or any State of Arizona regulatory agency succeeding to its powers and functions.

"Accounting Report" shall mean the report prepared by TRANSCO that accounts for all of the installed cost of each transmission facility constructed or acquired by TRANSCO as a part of the TTS and classifies such facility or portion thereof and apportions its installed cost as an All Requirements Resource Facility, an Existing System Facility, a Load Growth System Facility, a Power Sale Resource System Facility, a Resource Facility, or a Reliability System Facility, for the purposes of Sections 2 and 6 hereof and consistent with Accounting Requirements.

"Accounting Requirements" shall mean the requirements of any system of accounts prescribed by the RUS as long as RUS is the holder of any obligation of a cooperative; provided, however, that if a cooperative is specifically required by another Governmental Authority to employ the system of accounts prescribed by that Governmental Authority, then "Accounting Requirements" means the system of accounts prescribed by that Governmental Authority; provided, further, however, that if RUS is not a holder of any obligation or, if a holder, RUS does not prescribe a system of accounts applicable to the cooperative, and the cooperative is not specifically required by another Governmental Authority to employ that entity's system of accounts, then "Accounting Requirements" means the requirements of Generally Accepted Accounting Principles or another comprehensive basis of accounting applicable to like entities conducting business similar to that of the cooperative. Generally Accepted Accounting Principles refers to a common set of accounting standards and procedures that are either promulgated by an authoritative accounting rulemaking body or accepted as appropriate due to widespread application in the United States.

"Additional AEPCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by AEPCO.

"Additional CSP Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by CSP.

"Additional TRANSCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by TRANSCO.

"Administrator" shall mean the Administrator of RUS or any other federal regulatory agency or department succeeding to the Administrator's power or functions as a lender or mortgagee to a cooperative.

"AEPCO" shall mean Arizona Electric Power Cooperative, Inc., a non-profit generation and transmission cooperative corporation organized under the Laws of the State of Arizona.

"AEPCO Available Resource(s)" shall mean that portion of AEPCO Resources representing operating reserves which can be sold on an interruptible basis and surplus to AEPCO Total Load.

"AEPCO By-law Amendments" shall mean the amendments to the AEPCO By-laws relating to governance, in the form adopted by AEPCO in accordance with the terms of the AEPCO By-laws and the Laws of the State of Arizona.

"AEPCO By-laws" shall mean the By-laws adopted and amended by the Members or Board of Directors of AEPCO in accordance with the Laws of the State of Arizona.

"AEPCO Class A Member" shall mean (i) any Class A Member which purchases power and energy from AEPCO pursuant to any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement and is listed in Recital B to the Partial Requirements Capacity and Energy Agreement; or (ii) is determined to be a Class A member by the terms of the AEPCO By-laws.

"AEPCO Closing Date Allocation and Attribution" shall mean the allocations and attributions to be made by AEPCO on the Closing Date, as set forth in Section 2.6 of the Member Agreement and Section 2.3 of the Restructuring Agreement.

"AEPCO Delivered Load" shall mean the aggregate of the demand requirements and the associated energy requirements of all electric loads served from AEPCO Resources (including distribution losses but not including reserves or transmission losses), and shall consist of:

1. The loads of All Requirements Members served from AEPCO Resources;
2. PRM*AEPCO Load;
3. PRM*AEPCO Sales;
4. Power Sales Loads; and
5. CSP AEPCO Load.

"AEPCO Employees" shall mean those individuals employed by AEPCO as of the Closing Date.

"AEPCO Federal Hydro Power Capacity" shall mean that amount of capacity on an hourly basis scheduled by AEPCO pursuant to Federal Hydro Power Agreements.

"AEPCO Load Forecast" shall mean a listing of the demand and associated energy requirements of AEPCO Total Load (by month for the Resource Forecast Period) to be served from AEPCO Resources

"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 the Partial Requirements Capacity and Energy Agreements and the Existing Wholesale Power Contracts.

"AEPCO Minimum Base Capacity" shall mean the capacity from Available Base Capacity that must be operated from time to time to maintain system reliability or for other reasons, reflecting AEPCO's determination as to the schedule of energy from the Federal Hydro Power Agreements and AEPCO Minimum Coal Capacity.

"AEPCO Minimum Coal Capacity" shall mean the minimum output for safe and reliable operation of Apache Units 2 and 3.

"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.

"AEPCO Notes" shall mean written instruments or notes which evidence the obligation of AEPCO for loans that in whole or in part financed the construction of AEPCO's generation and transmission facilities, the payment of which is guaranteed by the Government pursuant to the REAct, and those written instruments or notes of AEPCO outstanding on the Effective Date (with respect to the MEC Partial Requirements Capacity and Energy Agreement), the Agreement Date (with respect to the SSVEC Partial Requirements Capacity and Energy Agreement), or the Approval Date (with respect to the TRICO Partial Requirements Capacity and Energy Agreement) payable to the Government evidencing loans made by the Government, acting by and through the Administrator of RUS, pursuant to the REAct, or evidencing reimbursement obligations of AEPCO to the Government with respect to the Government's guarantee of the payment of certain notes payable to the order of FFB and all amendments, supplements, extensions, and replacements to, of, or for, such notes, and loans made by, or securities issued to, or obligations undertaken to, others, including the Financial Entities. AEPCO Notes in the future will also include written instruments, which may evidence additional or new loans or advances that AEPCO may obtain to finance the construction or purchase of new facilities, Future Resources or the modification of Existing Resources, as applicable.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Retained Personnel" shall mean AEPCO management and other personnel designated as such by the chief executive officer of AEPCO.

"AEPCO's Revenue Requirement" shall mean the total revenues, from any source whatsoever, necessary to enable AEPCO, utilizing a twelve (12) 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) include 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, determined in accordance with Accounting Requirements.

"AEPCO's Revenue Requirement from AEPCO's Class A Members" shall mean that portion of AEPCO's Revenue Requirement less revenues anticipated by AEPCO from all other sources than the AEPCO Class A Members.

"AEPCO's Revenue Requirement From Partial Requirements Members" shall mean that portion of AEPCO's Revenue Requirement from AEPCO Class A Members allocated to Partial Requirements Members in accordance with Section 5 of the Partial Requirements Capacity and Energy Agreements and Section 3 of Rate Schedules A.

"AEPCO Scheduling Portal" shall mean an Internet web site maintained by AEPCO and accessible by all Class A Members for the purpose of AEPCO posting ongoing information relating to the availability and minimum must run requirements for AEPCO Resources.

"AEPCO Secured Obligations" shall mean the AEPCO Notes, loans made by, or securities issued to, or debt obligations entitled to the lien created by the AEPCO Mortgage.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Agreement Date" shall mean the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC.

"All Requirements Member" shall mean any Class A Member of AEPCO that is currently a party to any Wholesale Power Contract with AEPCO which provides for the purchase from AEPCO of all such Member's requirements of electric power, which as of the Effective Date consisted of ANZA, DVEC, GCEC, SSVEC AND TRICO, which as of the Agreement Date consisted of ANZA, DVEC, GCEC and TRICO, and which as of the Approval Date shall consist of ANZA, DVEC and GCEC.

"All Requirements Resource Facility" shall mean any System Facility, or portion hereof, or Direct Assignment Facility that is required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future resource in which MEC and SSVEC have no ACP.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in its Partial Requirements Capacity and Energy Agreement. The AC for each

month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of such agreement.

"Allocated Capacity Percentage" or "ACP" of a Class A Member shall mean the percentage allocation with respect to an AEPCO Resource, for which, if it is a Partial Requirements Member, such Member is responsible, including the allocation of electric capacity, cost responsibility and revenues, as set forth in its Partial Requirements Capacity and Energy Agreement. Appendix A to Exhibit A-5 to Rate Schedule A sets forth the ACP for each Class A Member with respect to Existing Resources and the S&G PPA.

"Ancillary Services" shall mean the ancillary services required by FERC to be made available with transmission service in accordance with the FERC pro-forma open access transmission tariff, including; but not limited to scheduling, system control and dispatch service; reactive supply and voltage control from generation sources service; regulation and frequency response service; energy imbalance service; operations reserve-spinning reserve service, and; operating reserve - supplemental reserve service, all as such terms are further defined by FERC in Order No. 888 and 889 and identified in transmission tariffs and service agreements of TRANSCO.

"Annual Planning Report" shall mean the annual written report and analysis given to AEPCO of a Class A Member's short, intermediate and long-range forecast of load and such other planning data required by the Resource Integration Agreement.

"Annual Transmission Requirements Report" shall have the meaning set forth in Section 5 of Schedule B hereto (Transmission Planning Policies).

"ANZA" shall mean Anza Electric Cooperative, Inc., a non-profit electric cooperative corporation organized and existing under the Laws of the State of California.

"Applicable Additional Contract" shall mean each additional contract as set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement, which either the Restructuring Agreement or the Member Agreement requires to be executed by each party to the Agreements.

"Approval Date" shall mean the first day of the month, no earlier than December 1, 2010, following the latter of 1) the date upon which the TRICO Transmission Agreement and the TRICO PRC&EA shall have been approved by the RUS, 2) the date upon which the TRICO PRC&EA shall have been approved by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

"ARM Energy Cost Responsibility Share or ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Assignment for Security" shall mean an assignment, transfer, mortgage or pledge of a party's interest in an Agreement made as security for any obligation secured by any

indenture, mortgage, deed, deed of trust, security instrument, or similar lien on its system assets, without limitation on the right of the secured party to further assign such Agreement.

"Authorized Representative" shall mean a representative designated by a party pursuant to the terms of an Agreement and authorized to act for such party in certain matters as set forth in the relevant terms of such Agreement.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available Resource(s)" shall mean the Pooled Resource(s) surplus to Pooled Load available for sale or dispatch as Merchant Sales.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Available Transmission Resources" shall mean the transmission facilities and contract rights of the Parties (as set forth in Schedule E attached) required for the delivery of Pooled Resources to Pooled Loads.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer Energy of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"Bonds" shall mean the CFC Guaranteed Solid Waste Disposal Revenue Bonds (Series 1994Adw) and the CFC Guaranteed Pollution Control Revenue Refunding Bonds (Series 1997C).

"CARM or Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources applicable to each All Requirements Member of AEPCO as set forth in Appendix A to Exhibit A-5 to the Rate Schedule A of the ARM Wholesale Power Contracts.

"CFC" shall mean the National Rural Utilities Cooperative Finance Corporation, a corporation organized under the Laws of the District of Columbia, or similar successor agency.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's By-laws.

"Closing" shall mean the execution and delivery of any and all documents and the tendering, transferring or delivering of all payments required to be made or otherwise necessary or desirable to consummate the transactions contemplated by the Restructuring Agreement and the Member Agreement, including such actions and documents described in the Closing Memorandum as specified in Section 8.1 of both the Restructuring Agreement and the Member Agreement, following satisfaction or waiver, if any, of the conditions for Closing therein.

"Closing Date" shall mean the date on which the Closing occurs.

"Closing Memorandum" shall mean the memorandum agreed to by the parties to the Member Agreement prior to the Pre-Closing which sets forth the consents, assignments, transfers, delivery of other approvals, documents, legal opinions, payments and transaction documents to be furnished by the parties, other conditions for Closing, and events and actions required to effect the Closing

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Collected Funds" shall mean deposited funds in a banking institution that are immediately available for use without any float restrictions.

"Contract Rate of Interest" shall mean the lesser of: (i) the interest rate equal to the effective "Prime Rate" per annum as specified in the "Money Rates" section of the Wall Street Journal or, (ii) the maximum interest rate permitted by applicable Law in the State of Arizona if any is so stated.

"Cost Causation" shall mean the identification of all direct and indirect costs, revenue and billing units associated with individual Resources and services, such that costs, revenue and billing units can be accounted for and billed separately to the specific Class A Members participating in such Resource or receiving such service.

"CSP" shall mean Sierra Southwest Cooperative Services, Inc., a non-profit corporation organized under the generation and transmission cooperative corporation Laws of the State of Arizona.

"CSP Actual AEPCO Load Data" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP AEPCO Load" shall mean the sum of the demand and associated energy requirements, including distribution losses, but not including reserves or transmission losses, of the Member JMP Load of each Class A Member and of those other loads for which CSP purchases capacity and energy from AEPCO as specified in separate sales agreements between AEPCO and CSP.

"CSP AEPCO Load Forecast" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP Assets" shall mean all capital stock of TSEPP, personal property, authorization to make Retail Sales, intangible assets, employee benefit plans, intellectual property, software licenses, employee or consultant agreements, equipment leases and contracts, licenses, any chose in action, and other agreements related to the performance of the CSP Business identified on Schedule 2 to the Restructuring Agreement.

"CSP Business" shall mean (i) the business of power sales and retail sales; (ii) the provision of personnel and consulting services to AEPCO, TRANSCO, and others pursuant to contract; and, (iii) the ownership and use of the CSP Assets, including responsibility for CSP Liabilities.

"CSP JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of those loads within a Member's Distribution Service Area served using capacity and energy provided by CSP from CSP Resources pursuant to a Joint Marketing Agreement between a Class A Member and CSP.

"CSP Liabilities" shall mean (i) the CSP liabilities identified on Schedule 2 to the Restructuring Agreement, as such obligations exist as of the Closing Date; and (ii) such other obligations relating to the performance of the CSP Business as CSP, AEPCO and TRANSCO may agree upon from time to time in other agreements; and (iii) any liabilities which CSP assumes in accordance with its By-laws.

"CSP Member" shall mean AEPCO, TRANSCO and the Class A Members of AEPCO on the Closing Date and any Person, which has become and retains membership in CSP in accordance with the CSP By-laws.

"CSP Resource" shall mean a Resource owned or purchased by CSP from third parties.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Debt Service Coverage Ratio" or "DSC" shall mean the financial ratio determined, based on figures shown on RUS Form 12 for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) depreciation and amortization expense, (b) interest on long-term debt (increased by one-third of the amount, if any, by which long-term leases exceed two percent of total margins and equities less regulatory assets), and (c) net patronage capital or margins and (2) dividing the sum obtained by the total of interest and principal billed under long-term debt and debt service requirements.

"Deficiency Purchase" shall mean the purchase of additional capacity and energy through the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1.1 herein, which purchase is required to supply capacity and associated energy to meet AEPCO Total Load, if it is the Purchasing Party, or MEC Total Load if MEC is the Purchasing Party.

"Delivery Point" shall mean the interconnection between the TTS and the transmission, distribution system or load of a Class A Member at which TRANSCO is to deliver capacity or energy pursuant to the Transmission Agreement or the Network Service Agreement.

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

"Direct Assignment Facilities" shall mean those transmission lines, substation facilities (or components thereof) and firm wheeling purchased by TRANSCO, for the sole use and benefit of a TRANSCO Member or of a particular transmission customer receiving service under the TRANSCO Tariff.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.

"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"DVEC" shall mean Duncan Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Economy Purchase(s)" shall mean a wholesale purchase of capacity and/or energy for a term not to exceed one year (including all renewal periods) entered into by AEPCO.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sale(s)" shall mean a wholesale sale by AEPCO of capacity and energy from AEPCO Available Resources made for monthly, daily or hourly periods of the next twelve months on a pre-scheduled basis.

"Economy Sales Price" shall mean for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Effective Date" shall mean either (i)_________________, or (ii) the Closing Date.

"Eligible Customer For TRANSCO " shall mean any of the following: (i) any electric utility (including AEPCO, CSP or any power marketer), Federal Power Marketing Agency, or any Person generating electric energy for sale for resale (electric energy sold or produced by any such entity may be produced in the United States, Canada or Mexico) or (ii) any Person offering retail electric service to others or taking retail service pursuant to a state requirement that TRANSCO offer unbundled transmission service or to a voluntary offer of such service by TRANSCO.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Engineering Analysis Requirement" shall mean have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.

"Equity" shall be defined in accordance with Accounting Requirements.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G and Supplemental Billing Energy.

"Exercise Date" shall mean date certain on or before which The Possible Selling Party or Parties shall provide notice to the Purchasing Party or Parties of an election pursuant to Section 10.1.1 herein to exercise The First Right of Refusal among AEPCO and MEC.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth and designated as Existing Resources in Appendix B to Exhibit A-5 to Rate Schedule A, consisting of Base Resource(s) and Other Resource(s).

"Existing System Facility" shall mean any System Facility that is in service or has been acquired as of the Agreement Date, and improvements thereto and replacements thereof occurring during the term of the Agreement.

"Existing Wholesale Power Contract" shall mean the Wholesale Power Contract between AEPCO and a Class A Member, and when used in the plural shall mean such contract and similar contracts between AEPCO and each of the Class A Members pursuant to which, in either case, such Class A Member purchases or purchased all its requirements of electric power from AEPCO prior to its becoming a Partial Requirements Member.

"FERC" shall mean the Federal Energy Regulatory Commission, an agency of the United States Department of Energy, or regulatory agency succeeding to the powers and functions thereof.

"Federal Hydro Power Agreement(s) shall mean 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 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).

"FFB" shall mean the Federal Financing Bank, an instrumentality and wholly owned corporation of the Government or any agency or department of the Government succeeding to the powers and functions thereof.

"Final Load Ratio Share of PRM*" shall mean the Load Ratio Share of PRM* in effect as of the Last Service Date.

"Financial Entities" shall mean collectively RUS, CFC, FFB, the trustees and bondholders of the Bonds and other lending institutions or issuers of debt who have made loans to or hold securities or other obligations of a cooperative.

"First Right(s) of Refusal" shall mean reciprocal one-time rights of first refusal to sell capacity and associated energy granted by the purchasing party to the selling party pursuant to Section 10.1 of the Resource Integration Agreement. Certain conditional first rights of refusal provided by CSP to AEPCO as set forth in Section 14 of the Resource Integration Agreement shall not be deemed to form a part of this defined term.

"First Right(s) of Refusal Period" shall mean the time period during which the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1 of the Resource Integration Agreement shall be in effect commencing on the Effective Date and ending on September 1, 2001.

"Fixed Charge" shall mean the charge computed in accordance with Section 5.2 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Force Majeure" shall mean the occurrence or non-occurrence of any act, event or cause beyond the control of a party to an Agreement whereby the party is unable to perform its obligation, other than the obligation to pay money, which act, event or cause by that party's exercise of due diligence could not have reasonably been expected and avoided, or which even with the exercise of due diligence, the party has not been able to overcome or avoid or cause to be avoided. Such act, event or cause shall include, but not be limited to: acts of God; failure or threat of immediate failure of facilities; explosions, flood, drought, earthquake, storm, fire, pestilence, lightning and other natural catastrophes; epidemic; war; riot; civil disturbance or disobedience, strike, or labor disturbance, disputes or unrest of whatever nature; civil disputes or unrest of whatever nature; labor, material or fuel shortage; sabotage; vandalism; restraint by court order or public authority; a failure or threat of failure of any generating or transmission facility, which is likely to cause an outage of electric service to customers served from that party's system (including transmission curtailments by a transmission provider) or to cause such party to experience a rapid decline in system voltage or frequency; and, action or non action by or inability to obtain the necessary authorizations or approvals from any Governmental Authority (but not including the ACC or RUS), provided however, that no act, event or cause that is the result of the lack of necessary financial resources shall constitute an event of "Force Majeure," nor shall an act, event or cause that is the result of the negligence of the party claiming Force Majeure constitute an event of "Force Majeure."

“Form 12A Balance Sheet” shall mean RUS Form 12a, Section B, Balance Sheet.

“FPPCA” shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

“FPPCA Period” shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

“Future Resource” shall mean (i) any new AEPCO Generating Resource, or (ii) any AEPCO Power Purchase Resource with a term of greater than one (1) year; either of which Resource would require the assignment of a new ACP to each Class A Member participating in such Resource and an amendment, or a new Exhibit to Rate Schedule A.

“Future Scheduling Hour” shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

“Gas Energy Cost” shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

“Gas Energy Generated” shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

“Gas Energy Rate” shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

“GCEC” shall mean Graham County Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona

“Generally Accepted Auditing Standards” shall mean a common set of auditing standards and procedures that have been developed over time by several auditing boards, the most current set of standards and procedures of which is the Auditing Standards Board.

“Generating Resource” shall mean an interest in any existing, additional, modified or repowered generating facility or unit, which may be owned (jointly or individually), leased or otherwise acquired by AEPCO, provided that in connection with any lease of an Existing Resource, such leasehold interest shall not be deemed to be a Future Resource for purposes of the Partial Requirements Capacity and Energy Agreement.

“Generation Business” shall mean with respect to AEPCO: (i) the business of generation of electricity; (ii) operation of the Resource Pool; and, (iii) the use, ownership, rights, obligations and duties associated with the generation assets including its agreements for Power Purchase Resources, Power Sales Resources, Economy Purchases and Economy

Sales including, but not limited to, the Existing Wholesale Power Contracts and the Partial Requirements Capacity and Energy Agreement.

"Government" shall mean the federal government of the United States of America.

"Governmental Authority" shall mean any local, state, regional, federal, or national administrative, legal, judicial, or executive governmental agency, commission, department, or other governmental entity having jurisdiction over AEPCO, TRANSCO, CSP, their respective Members, or any of their activities.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Indebtedness" shall mean:

(1) debt incurred or assumed by a cooperative for borrowed money, or debt incurred for the reimbursement of money advanced under any credit support agreements if in either case categorized as debt according to Accounting Requirements;

(2) lease obligations, if categorized as debt according to Accounting Requirements;

(3) debt incurred or obligations assumed for facilities or power purchases included in a Member's ACP;

(4) debt incurred or obligations issued to finance the amount of a pre-payment; or

(5) debt for any Person (other than debt otherwise treated as Indebtedness hereunder) described in clauses (1), (2), (3) or (4) above which are guaranteed (whether by payment or collection) by the cooperative, provided that none of the following shall constitute Indebtedness:

  (A) guarantees of performance or payment by, or any obligations of, any Person under contracts to pay for fuel for the system; and

  (B) guarantees of performance by any Person for other than payment of debt incurred or assumed for borrowed money, or any obligation if categorized as debt according to Accounting Requirements, including, without limitation, all debt (other than indebtedness otherwise treated as Indebtedness hereunder) for borrowed money or the acquisition, construction or improvement of property or capitalized lease obligations guaranteed directly or indirectly, in any manner by a cooperative, or in effect guaranteed, directly or indirectly, by such cooperative through an agreement, contingent or otherwise, to assume any such indebtedness or to advance or supply funds for the payment or purchase of any such indebtedness or to purchase property or services primarily for the purpose of enabling the debtor or seller to make payment of such indebtedness, or to assure the owner of the indebtedness against loss, because of such indebtedness or to supply funds to or in any other manner invest in the debtor (including any agreement to

pay for property or services irrespective of whether or not such property is delivered or such services are rendered) or otherwise.

"Interest Expense" shall mean an amount constituting interest on long-term Indebtedness (less any interest during construction and allowance for funds used during construction including an interest rate swap collar, floor forward or other hedging agreement, arrangement or security, however denominated) and other interest expense computed in accordance with Accounting Requirements.

"Intra-Day Schedule" shall mean a Real-Time Schedule.

"Joint Marketing Agreement" shall mean an agreement by and between CSP and a Class A Member pertaining to joint competitive retail electric marketing and sales activities, in accordance with applicable Law, within such Member's Distribution Service Area.

"Joint Marketing Plan" shall mean a plan designed by and entered into between CSP and a Class A Member concerning Retail Sales, the form of which is set forth in Exhibit B to the Joint Marketing Agreement.

"Last Service Date" shall mean the last date on which TRANSCO provides service to PRM* pursuant to Section 2 of a PRM* Transmission Agreement, unless otherwise extended by mutual agreement of the Parties as set forth in writing.

"Law" shall mean any applicable treaty, statute, code, constitutional provision, ordinance, rule, regulation, order, judgment, decree, decision, injunction, process or any similar form of legally binding decision or directive issued by any Governmental Authority including permits and regulatory approvals and any applicable common law.

"Legal Requirement" shall mean any obligation of AEPCO or TRANSCO required by Law.

"Load Forecast" shall mean he projections of monthly coincident peak kilowatt and total monthly kilowatt-hour loads of a party to an Agreement.

"Load Growth System Facility" shall mean any System Facility or portion thereof that is not an All Requirements Resource Facility or a Resource Facility and is constructed or acquired by TRANSCO to deliver the power and energy of any Future Resource or Resource Modification to All Requirements Members for serving the portion of total load of All Requirements Members that is in excess of the sum of the collective AC of All Requirements Members in Existing Resources with all Power Sales Resources reduced to zero.

"Load Pool" shall mean those Pooled Loads served from Pooled Resources.

"Load Ratio Share" shall have the meaning set forth in the TRANSCO Tariff.

"Load Ratio Share of PRM*" shall mean the ratio, expressed as a decimal, that results from dividing: (i) the demand of PRM* AEPCO Load at the time of the TRANSCO system Peak, by (ii) the sum of: (a) the actual total of the demands of all firm loads of all TRANSCO

customers at the time of the TRANSCO system peak, including PRM* plus (b) the reserved transmission capacity of all TRANSCO customers receiving firm point to point transmission service under the TRANSCO Tariff, less (c) the actual demands at the time of the TRANSCO system peak of the loads of TRANSCO's customers receiving firm point to point transmission service under the TRANSCO Tariff. Such ratio shall be calculated on a rolling twelve month basis.

"Long Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period extending beyond the subsequent five calendar years.

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

"MEC" shall mean Mohave Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Member" shall mean a member of AEPCO, a CSP Member or a TRANSCO Member, as applicable.

"Member Actual AEPCO Load Data" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member AEPCO Load Forecast" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member Agreement" shall mean the Member Agreement as executed and delivered by and among the Class A Members, AEPCO, TRANSCO and CSP, dated July 2, 2001.

"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's Member Peak Demand purchased by Member from AEPCO pursuant to a PRM* Partial Requirements Capacity and Energy Agreement, which consists of the demands of PRM* AEPCO Load and PRM* AEPCO Sales.

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

"Member JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses of loads located within a Member's Distribution Service Area served using capacity and energy provided by CSP as a result of a Joint Marketing Agreement between CSP and a Class A Member, for which CSP purchases capacity and energy from AEPCO.

"Member Transaction" shall mean (i) the consolidation or merger by the Partial Requirements Member with any other Person; (ii) the reorganization or change of the form of the Partial Requirements Member's business organization from an electric cooperative non-profit membership-owned corporation; or, (iii) the sale, transfer, lease, or other disposal of all or substantially all the Partial Requirements Member's assets to any Person (or any effort or agreement therefor), whether accomplished in a single transaction or contemplated through a series of transactions as set forth in Section 12 of the Partial Requirements Capacity and Energy Agreement and the Transmission Agreement.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member's *Distribution* Service Area" shall mean the geographical electric service territory of a Class A Member as certificated by the ACC, the California Public Utility Commission or the New Mexico Public Utility Commission, as applicable, to supply distribution service as well as all other territory so served by such Class A Member pursuant to applicable Law, or any inter-utility border agreement.

"Merchant Purchase(s)" shall mean a wholesale purchase of capacity and/or energy (pursuant to Section 11 herein) for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to: (i) minimize the cost of energy production from Pooled Resources, and (ii) displace energy from Pooled Resources of higher Pool Price.

"Merchant Sale(s)" shall mean a wholesale sale of capacity and/or energy (pursuant to Section 11 herein) from Surplus Resources for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to use Surplus Resources for the economic benefit of the Pool Resource Owners.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Minor Resource Modification" shall mean an addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of an AEPCO Power Purchase Resource for five years or less, undertaken by AEPCO in its sole discretion, which will not: (i) increase of greater than ten percent the capacity of the AEPCO Resource being modified; (ii) result in an increase of greater than five percent in AEPCO's Revenue Requirement From AEPCO's Class A Members upon the operation of such addition, improvement, repair and modification or extension, as the case may be; or, (iii) extend the term of any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement.

"Must-Pool Load(s)" shall mean those loads of AEPCO, CSP and MEC which Section 3 herein requires be served from the Resource Pool.

"Must-Pool Resources" shall mean AEPCO Resources and those Resources of CSP and the Partial Requirements Member, which are required to be included in the Resource Pool.

"Native Load" shall mean (i) for AEPCO, the electric load of wholesale power customers of AEPCO on whose behalf AEPCO, by Law, tariff or contract, has undertaken an obligation to construct, or otherwise obtain, reliably operate and provide AEPCO Resources (including Purchase Power Resources of AEPCO) to meet the electric requirements of such customers and shall include, but not be limited to, AEPCO Delivered Load, (ii) for TRANSCO, "Native Load" shall mean the electric loads of the TTS customers on whose behalf TRANSCO, by Law, tariff or contract (including as TTS successor to AEPCO) has undertaken an obligation to construct and operate the TTS and shall include, but not be limited to, AEPCO Delivered Load, and (iii) for a Member, "Native Load" shall mean the electric load of the customers of a Member to whom such Member sells power and/or energy and on whose behalf the Member, by Law, tariff, or contract, has undertaken an obligation to construct, or otherwise obtain, and reliably operate the Member's system to meet the power supply requirements of such customers.

"Near Term" shall mean" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period not to exceed the subsequent two calendar years.

"NERC" shall mean the North American Electric Reliability Council, or entity or agency succeeding to its powers and functions.

"Net Utility Plant" shall mean total utility plant less accumulated depreciation as computed consistent with Accounting Requirements.

"Network Integration Transmission Service" shall described in Part III of the TRANSCO Tariff.

"Network Loads" shall have the meaning set forth in Section 1 of the TRANSCO Tariff. The Delivery Points of the Network Loads of Member served pursuant to this Agreement are set forth in Schedule C hereto.

"Network Loss Factor" shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

"Network Resources" shall have the meaning set forth in Section 1 of the TRANSCO Tariff.

"Network Service Agreement" shall mean the Network Service Agreement by and between TRANSCO, AEPCO and the All Requirements Members, substantially in the form attached as Exhibit B-1 to the Member Agreement.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Non-Generation Assets" shall mean as determined in accordance with Accounting Requirements, all assets of AEPCO of every kind, description, and location which shall be acquired by TRANSCO from AEPCO, as of the Closing Date, which are set forth in Schedule 1 to the Restructuring Agreement.

"Non-Pool Loads" shall mean those loads of a Partial Requirements Member or CSP or applicable portions of such loads which are not included in Pooled Loads.

"Non-Pool Resource" shall mean any Resource obtained by a Partial Requirements Member or CSP and which is not included in the Resource Pool.

"O&M" shall mean the general accounting term used to describe activities and expenses involved with the use, operation, maintenance and repair of a cooperative's plant and facilities including expenses associated with activities intended to prevent or remedy an impending or actual breakdown of those facilities. The term O&M does not include the enlargement or improvement of the property owned or leased and operated by a cooperative nor does it include the replacement of retirement units.

"O&M Charge" shall mean the charge computed in accordance with 5.3 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Off-Peak Hours" shall mean those hours defined by the Western Systems Coordinating Council to represent off-peak load periods, which for each day consist of the eight hours of the hour ending at 2300 through hour ending at 0600, Mountain Standard Time, and the remaining hours of each Sunday and of each of six holidays (New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day).

"Operating Committee" shall mean the standing committee(s) established in the Partial Requirements Capacity and Energy Agreement and assigned by the parties thereto to deal on a prompt and orderly basis with certain technical and operating issues that may arise in connection with system development or operations.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Optional Pool Resources" shall mean those Resources which a party may commit to the Resource Pool.

"Order No. 888" shall mean that certain FERC order Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. para. 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. para. 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC para. 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC para. 61,046 (1998).

"Order No. 889" shall mean that certain FERC order Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs. para. 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & Regs. para. 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC 61,253 (1997).

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period,

as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean, Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Peak Hours" shall mean all hours of each day which are not Off-Peak Hours.

"Performance Default" shall meant the default by either party to a Partial Requirements Capacity and Energy Agreement, a Transmission Agreement, a Network Service Agreement, or a Joint Marketing Agreement, whereby, as provided by the terms of each such Agreement, such party fails to comply, after any notice of such failure and opportunity to cure, with any of the respective terms, conditions, obligations or covenants of such Agreement.

"Person" shall mean an individual, partnership, association, limited liability company, corporation, membership corporation, business trust, joint stock company, trust, cooperative, unincorporated organization, joint venture, or other entity.

"PGR Purchase Agreement" shall mean the Power Purchase Agreement between Panda Gila River, L.P., and AEPCO, dated April 15, 2003, as amended.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Planning Services" shall mean bulk power supply planning and Future Resource procurement services.

"Pool Price" shall mean the price, in mills/kWh, established for a Pooled Resource pursuant to Appendix A-2 of the Resource Pooling Policies.

"Pool Resource Owner" shall mean a Party that has committed Resources to the Resource Pool pursuant to Section 4 herein.

"Pooled Loads" shall mean the aggregate total electric load and sales of the parties that are to be served by Pooled Resources, including distribution losses and not including reserves or transmission losses.

"Pooled Resources" shall mean those Resources which have been committed to the Resource Pool.

"Possible Selling Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Factor" shall mean the cosine of the phase angle between the voltage and the current. Power Factor can be lagging or leading indicating whether the current is lagging or leading the applied voltage.

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

"Power Purchase Resource" shall mean capacity and energy or energy purchased by a party under a contract with a term greater than one year, including any such capacity and energy or energy purchased or acquired pursuant to (i) the Public Utility Regulatory Policies Act of 1978, as it may be amended from time to time, or (ii) the Environmental Portfolio Standard set forth in A.A.C. R14-2-1618, as it may be amended from time to time, as adopted by the Arizona Corporation Commission.

"Power Sale(s)" shall mean a wholesale sale of capacity or energy for a term of one year or more. Power Sales do not include Retail Sales.

"Power Sales Load" shall mean the demand and energy requirements of the load associated with Power Sales Resource(s).

“Power Sales Resource” shall mean a sale of capacity and energy from Existing Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

“Power Sales Resource Demand Revenues” shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity’s ACP in Existing Resources.

“Power Sales Resource Energy Revenue” shall mean, for a billing period, the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period

“Power Sales Resource System Facility” shall mean any System Facility or portion thereof that is required to enable delivery of capacity and energy to Class A Members from expired Power Sales Resources which existed as of the Effective Date.

“Pre-Closing” shall mean the execution and delivery of all documents that are a condition to Closing, as further described in the Closing Memorandum.

“Pre-Schedule” shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

“Pre-Schedule Day” shall mean the day on which a Pre-Schedule must be submitted for the next Scheduling Day.

“PRM” shall mean a Partial Requirements Member.

“PRM*” shall mean a term in definitions which may be replaced with the name of a PRM so that the definition would apply only to the specified PRM (see Section 3.8 above).

“PRM* 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 (or served from line extensions therefrom) for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement, but shall not include PRM* Wheeling Load. Such demand and energy requirements are included within PRM* Metered kW and PRM* Metered kWh. The demand component of PRM* AEPCO Load numerically consists of the coincident aggregate, at a specific time, of: (i) PRM* Metered kW; less (ii) kW of PRM* Wheeling Load; less (iii) kW of Member JMP Load of PRM*; less (iv) kW of CSP JMP Load of PRM*; (v) less Kw of PRM* Internal Load. The energy component of PRM* AEPCO Load numerically consists of the aggregate during a specific time interval of: (i) PRM* Metered kWh; less (ii) kWh of PRM* Wheeling Load; less (iii) kWh of Member JMP Load of PRM*; less (iv) kWh of CSP JMP Load of PRM*; less, (v) kWh of PRM* Internal Load.

"PRM* 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 PRM* to wholesale buyers or to end use loads which are external to Member's Distribution Service Area of PRM* for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement. The demand and energy requirements of PRM* AEPCO Sales shall be metered (or determined) as agreed between PRM* and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery.

"PRM* External Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located external to the Member's Distribution Service Area of PRM* (and not served from line extensions therefrom) for which PRM* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* External Load are not included in PRM* Metered kW and Member* Metered kWh, respectively.

"PRM* Internal 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 PRM* (or served from line extensions therefrom) for which Member* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* Internal Load are included in PRM* Metered kW and PRM* Metered kWh, respectively.

"PRM* Metered kW" shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Metered kWh " shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and PRM*.
"PRM* Resource(s)" shall mean a Resource of a Partial Requirements Member of AEPCO; PRM* Resource does not include the capacity and energy purchased from AEPCO under the PRM* Partial Requirements Capacity and Energy Agreement, or purchased by AEPCO under separate contract.

"PRM* Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and PRM* for the purposes of PRM* Transmission Service.

"PRM* Transmission Service" shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load.

"PRM* Wheeling Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within Member's Distribution Service Area of PRM* (or served from line extensions therefrom), which are supplied by capacity and energy from third parties (and not from Member Resources or the AC of PRM*) and for which PRM* provides delivery services over its

distribution system. The demand and energy requirements of PRM* Wheeling Load are included within PR* Metered kW and PRM* Metered kWh, respectively.

"Project Approval" shall mean the approval required by Section 3.4.5 of the Partial Requirements Capacity and Energy Agreement for a Resource Modification.

"Proposal and Analysis" shall have the meaning set forth in Section 3.4.3 of the Partial Requirements Capacity and Energy Agreement.

"Prudent Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to include a spectrum of possible practices, methods, or acts generally acceptable in the region that could be expected to accomplish the desired result at a reasonable cost consistent with reliability, safety and expedition in light of the circumstances.

"Purchasing Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Rate Schedule A" shall mean the Schedule A to the Partial Requirements Capacity and Energy Agreements or to an Existing Wholesale Power Contract.

"REAct" shall mean the Rural Electrification Act of 1936.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Receipt Point" shall mean the interconnection between the TTS and the transmission, sub-transmission, generating resource or distribution facilities at which TRANSCO is to accept capacity or energy from AEPCO Resources for delivery pursuant to the Transmission Agreement or Network Service Agreement, and from which TRANSCO provides transmission service to the Delivery Point.

"Reliability System Facilities" shall mean System Facilities and/or improvements that are constructed and installed or acquired by TRANSCO to enhance or maintain the reliability of the TTS as required by the transmission system performance criteria of the NERC, as applied within the WECC, consistent with Prudent Utility Practice.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing

period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Remaining Equity Investment of TRANSCO" shall mean that portion of the installed cost of a System Facility or Direct Assignment Facility financed by an equity contribution of TRANSCO (with interest accrued thereon) which remains undepreciated on the Last Service Date (or the date of closing of a transaction between the parties involving the disposition of a Direct Assignment Facility).

"Remaining Indebtedness of TRANSCO" shall mean the principal balance remaining unamortized as of the Last Service Date (or the Date of Closing of a transaction between the Parties involving the disposition of a Direct Assignment Facility) of that portion of the installed cost of a System Facility or Direct Assignment Facility financed by TRANSCO debt, with interest accrued thereon, which remains unamortized on the Last Service Date or termination or exercise of an option to purchase the Direct Assignment Facilities serving SSVEC (plus any actual prepayment penalties incurred from the prepayment of such debt).

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"Required Modification" shall have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.
"Resource" shall mean either a Generating Resource or Power Purchase Resource.

"Resource Acquisition" shall mean the performance of analyses of Resource needs or Resource sales proposals, the recommendation of a Power Purchase Resource or Generating Resource, and the negotiation of and acquisition for AEPCO of a Resource.

"Resource Deficiency" shall mean a deficiency in AEPCO Resources available to serve Class A Members and Power Sales Loads.

"Resource Facility" shall mean any System Facility, or portion thereof, or Direct Assignment Facility required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future Resource in which SSVEC has all ACP.

"Resource Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending upon the earlier of:(a)the twentieth anniversary thereafter or (b) the last service date of a Class A Member's Wholesale Power Contract, as set forth in the Resource Planning Policies.

"Resource Integration Agreement" shall mean the multi-party agreement by and between CSP, TRANSCO, AEPCO and MEC and dated July 2, 2001, as amended to include SSVEC and TRICO as parties.

"Resource Modification" shall mean any addition, improvement, repair or modification to a Generating Resource or the modification or extension of the term of an existing Power Purchase Resource made by AEPCO which would: (i) increase the capacity of the AEPCO Resource by more than ten percent; or (ii) result in an increase of more than five percent in AEPCO's Revenue Requirement upon the operation of such addition, improvement, repair and modification, or extension, as the case may be, or (iii) require an extension of the term of an Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement. A Resource Modification shall not be construed to include a Minor Resource Modification.

"Resource Operation Policies" shall mean the resource operation policies set forth in Schedule B to the Resource Integration Agreement and Exhibit B2 to Schedule B of the Partial Requirements Capacity and Energy Agreement.

"Resource Planning" shall mean the process used to identify a deficiency in the amount of existing Resources needed to reliably meet anticipated load requirements (including reserves). Resource Planning includes a review of alternative Resources and the selection of the preferred Resources to be constructed or acquired to meet the deficiency.

"Resource Planning Policies" shall mean the resource planning policies set forth in resource planning and acquisition documents.

"Resource Pool" shall mean the capacity and energy pool which integrates the electric capacity and associated energy of AEPCO Resources with Resources owned or contracted for by the Partial Requirements Members and CSP, which the Partial Requirements Member or CSP is required to include or has designated for inclusion in such pool.

"Resource Pool Operation" shall mean that load and resource integration service provided by AEPCO.

"Resource Pooling Policies" shall mean the resource pooling policies set forth in Schedule A of the Resource Integration Agreement.

"Resource Pre-Schedule" shall mean a schedule of energy needed from the Resources of the Resource Pool to meet the aggregate of the Pooled Loads made on a least energy cost and a day-ahead basis.

"Restructuring Agreement" shall mean the Restructuring Agreement as executed and delivered by and among AEPCO, TRANSCO and CSP, dated the 11th day of October 2000.

"Retail Sales" shall mean sales arranged or made by CSP in the competitive retail electric market, including sales at retail from Surplus AEPCO Resources. Retail Sales do not include Power Sales.

"Revenue Shortfall" shall mean the failure of a cooperative to receive sufficient revenue to cover its revenue requirement.

"Rights of Way" shall mean the various rights of way and easements held by TRANSCO from time to time.

"RUS" shall mean the Rural Utilities Service, as successor-in-interest to the Rural Electrification Administration, which is an agency of the United States Department of Agriculture, or any agency of the Government succeeding to its powers and functions

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as a S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduled Day" shall mean the Scheduling Day, as defined by WECC, for which a Pre-Schedule has been submitted.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Scheduling Party" shall mean the owner of an Optional Pool Resource that qualifies to be a Pooled Resource but is not included in the Resource Pool and which is separately scheduled by such owner.

"SEC" shall mean the Securities and Exchange Commission, or any agency of the Government succeeding to its powers and functions.

"Separation of Functions and Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct referenced in Section 15 of the Resource Integration Agreement and set forth as Schedule F attached thereto.

"Service Agreement" shall mean the agreement entered into by a transmission customer or network customer and TRANSCO for transmission service or network service under Part II or Part III respectively, of the TRANSCO Tariff.

"Service Agreement(s) for Firm and Non-Firm Transmission and Ancillary Services" shall mean any Service Agreement by and between TRANSCO and AEPCO for transmission

service pursuant to Part II of the TRANSCO tariff, substantially in the form of agreement attached to the TRANSCO Tariff.

"Short Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period greater than the subsequent two calendar years but lasting less than five calendar years.

"Southwest" shall mean TRANSCO.

"SSVEC" shall mean Sulphur Springs Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Staffing Agreement" shall mean each of the individual staffing agreements whereby CSP shall furnish personnel services to TRANSCO or AEPCO, respectively.

"Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct as set forth as Schedule F to the Resource Integration Agreement.

"Stranded Costs" shall mean any actual charge or cost (including any transmission or distribution surcharges, fee, competition transition charge, wires charge, adjustment, rate, system benefit charge, regulatory charge, regulatory asset surcharge, exit fee or any other mechanism or systematic recovery program approved for use for the recovery of stranded investments) that are permitted by the ACC pursuant to the ACC Electric Competition Rules, A.A.C. R14-2-1601, et seq. or successor rule, or otherwise assessed or levied in order to recover the expenses and liabilities associated with stranded investments including without limitation, regulatory assets, or costs associated with the introduction of competition in the retail sales of electric energy and capacity.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase

"Supplemental Energy Intrachange" shall have the meaning set forth in Section 6 of the Resource Pooling Policies.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made by AEPCO for a period of less than a year to serve load of CARM or a Member* CA Planning Contract Member in excess of CARM's or such Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Surplus AEPCO Resource(s)" shall mean AEPCO Resources available and not necessary or used to serve AEPCO Total Load.

"Surplus Resource" shall mean a Pooled Resource(s) that is surplus to Pooled Load and its operating reserves as determined by a Pool Resource Owner in accordance with Prudent Utility Practice.

"System Facilities" shall mean the transmission lines, substation facilities or components thereof and firm wheeling purchased by TRANSCO, which do not constitute Direct Assignment Facilities and are used to deliver capacity and energy to the Members and other transmission customers of TRANSCO.

"Tag" shall mean the collection of information in the electronic form of request and subsequent response as part of the process implemented by the North American Electric Reliability Corporation for electronically communicating a request for, securing approval of, and recording an energy transaction via the Internet.

"Tariff" shall mean at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sale" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported by AEPCO as an economy sale to RUS Uniform System of Accounts Number 447.

"Times Interest Earned Ratio" or "TIER" " shall mean the financial ratio determined based on figures shown on Form 12 Balance Sheet for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) net

patronage capital or margins and (b) Interest Expense on long-term Indebtedness, and (2) dividing the sum obtained by Interest Expense on long-term Indebtedness.

"Total Assets" shall mean an amount constituting the total assets of a Class A Member determined in accordance with Accounting Requirements.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

"TRANSCO", which is also known as "Southwest", shall mean Southwest Transmission Cooperative, Inc., a non-profit corporation organized under the Laws of the State of Arizona.

"TRANSCO Assumed AEPCO Debt" shall mean that portion of AEPCO's Indebtedness that TRANSCO assumes pursuant to the TRANSCO CFC Note (if required), the TRANSCO FFB Note(s), the TRANSCO RUS Note(s) and the TRANSCO Assumption and Indemnity Agreements, in each case, in accordance with applicable Law.

"TRANSCO Assumption and Indemnity Agreements" shall mean collectively the Assumption and Indemnity Agreements between TRANSCO and AEPCO and the trustees of certain financial instruments, the forms of which are set forth in Appendix A to the Restructuring Agreement pursuant to which TRANSCO will agree to assume the obligation to pay that portion of AEPCO's debt secured under the AEPCO Mortgage that AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO By-laws" shall mean the By-laws, in the form adopted by the TRANSCO Board of Directors or the TRANSCO Members, as appropriate.

"TRANSCO Employees" shall mean all persons employed by TRANSCO, including TRANSCO Management and systems operations personnel designated by the chief executive officer of TRANSCO, but shall not include persons employed by CSP or any other contractor.

"TRANSCO FFB Note(s)" shall mean the note(s) in the form required by FFB pursuant to which TRANSCO will assume and replace AEPCO as an obligor with respect to that portion of AEPCO's Indebtedness to the FFB outstanding as of the Effective Date that each of

AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO Member" or "Southwest Member" shall mean any of the Class A Members of TRANSCO, and others, including AEPCO and CSP, that become members of TRANSCO in accordance with the TRANSCO By-laws.

"TRANSCO Mortgage" shall mean the Mortgage and Security Agreement, dated as of the Effective Date, made by and among TRANSCO, RUS and CFC which secures the TRANSCO Secured Obligations.

"TRANSCO Notes" shall mean written instruments or notes which evidence the obligation of TRANSCO for its assumption of a portion of the AEPCO Indebtedness (the TRANSCO Assumed AEPCO Debt) to purchase the Transmission Business as evidenced and effected by delivery of the TRANSCO FFB Note(s) and the TRANSCO RUS Note(s), payable to or guaranteed by the Government, acting through the RUS, and by its assumption of the repayment obligations of a portion of the loans made by, or securities issued to, or obligations undertaken to the Financial Entities, and which in the future will also include written instruments which may evidence additional or new loans or advances TRANSCO may obtain to finance the construction or purchase of new facilities for the TTS or the modification of existing TTS facilities, as applicable.

"TRANSCO RUS Note" shall mean the simple allocation of the AEPCO Note owed to RUS.

"TRANSCO Secured Obligations" shall mean collectively, the TRANSCO Notes, certain of the loans made by others to TRANSCO, or securities issued to others by TRANSCO, or debt obligations entitled to the lien created by the TRANSCO Mortgage.

"TRANSCO Tariff" or "Southwest Tariff" shall mean the open access transmission tariff under which transmission services and Ancillary Services are offered by TRANSCO.

"TRANSCO Transmission System" or "TTS" shall mean the electric transmission system of TRANSCO including all transmission lines, substations, microwave and telecommunication facilities, system control and data acquisition system, inventories, works in progress, contract rights to provide or receive transmission services, leases, interests in joint transmission projects, licenses, other related transmission agreements and all other such transmission related assets.

"Transferee" shall mean any of the following Persons: (i) the Person formed as a result of a Member Transaction by any consolidation of the Partial Requirements Member with any other Person; (ii) the survivor of any merger or reorganization of the Partial Requirements Member; (iii) or a Person that acquires or leases all or substantially all of the electric assets of the Partial Requirements Member.

"Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and a Partial Requirements Member.

"Transmission Business" shall mean the performance of transmission services and Ancillary Services, and the ownership and use of any rights, obligations, duties, approvals and licenses to the Non-Generation Assets, including the Transmission Resources, and shall include responsibility for the Non-Generation Liabilities.

"Transmission Forecast" shall mean with respect to any Person, such Person's forecast, on an annual basis, of its transmission requirements from TRANSCO.

"Transmission Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending at least the tenth anniversary thereafter.

"Transmission Planning" shall mean the process by which the performance of an electric transmission system is evaluated with respect to specified load-serving capability in accordance with Prudent Utility Practice and by which future modifications, improvements and additions to such electric transmission system are determined by TRANSCO.

"Transmission Requirements Study" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TRICO" shall mean Trico Electric Cooperative, Inc., an electric cooperative non-profit corporation organized and existing under the Laws of the State of Arizona.

"TRS Work Plan" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TSEPP" shall mean TSE Promotional Products, Inc., an Arizona corporation.

"TTS" shall mean TRANSCO Transmission System.

"WECC" shall mean Western Electricity Coordinating Council, a regional division of NERC, and successor to WSCC.

"Wholesale Power Contract" shall mean a contract, including its amendments and modifications, including the Existing Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement, between AEPCO and a Class A Member of AEPCO, for the wholesale sale by AEPCO of electric power or electric power and transmission services to such Class A Member.

"Withdrawal Agreement" shall mean the form of withdrawal agreement attached to the Member Agreement as Exhibit D.

"WSCC" shall mean Western System Coordinating Council, a regional division of NERC.

Partial Requirements Members

RATE SCHEDULE A
Dated May 11, 2010

1. INTRODUCTION:

This Rate Schedule A specifies the rates and charges and the methodology for developing and administering those rates and the charges for capacity and energy sales made by AEPCO to Member pursuant to its 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 charges which are currently in effect in accordance with the Agreement. Exhibit A-2 specifies the methodology for calculating the rates and charges, 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 the methodologies for determining billing units, energy rates and energy charges using cost causation principles. Exhibit A-6 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 Existing Resources, the S&G PPA and Supplemental Purchases (the "Dispatch Pool Resources"). AEPCO may include the Dispatch Pool Resources in a larger pool for dispatch purposes, provided that the Billing Unit Program is maintained pursuant to Exhibit A-4 and the rights and benefits of each Class A Member are not diminished. No additional members may be added to the existing Class A Members with rights in the Dispatch Pool Resources, and changes in the membership shall be subject to Sections 12 and 13 of the Agreement.

AEPCO shall not enter into contracts for or acquire (i) any new AEPCO Generating Resource; or (ii) any AEPCO Power Purchase Resource with a term of greater than one year, unless AEPCO has first entered into a written agreement between AEPCO and all Class A Members agreeing to participate in such Resource, under which no related direct and indirect costs, charges and revenues derived from such Resource would be assigned to any non-participating Class A Members.

2. CONDITIONS OF SERVICE:

2.1 Applicability.

The rates, charges, and adjustments and the methodology for setting and adjusting such rates, charges and adjustments are set forth in this Rate Schedule A. Member shall make payment for electric service under the Agreement through the rates, charges and adjustments established by AEPCO in accordance with the Agreement and this Rate Schedule A. Member shall remain obligated at all times during the term of the 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 Adjustment.

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

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

Where:

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

2.3 Demand Overrun Adjustment.

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

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

Where:

doaf	=	demand overrun adjustment factor
mbdkW	=	Member Schedule in kW or Metered kW less capacity from sources outside the Dispatch Pool, as applicable, and
AC	=	Allocated Capacity of Member, in kW.

2.4 Taxes and/or Assessments.

The rates and charges 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 charges. 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 charges for capacity and energy sales for payment by Member.

2.5 Charges.

The monthly charge billed to 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 as set forth in Exhibit A-1 hereof; plus,

3. the Base Energy Charge and Base Fuel Cost Adjustor Charge, calculated as set forth in Exhibit A-4; plus

4. the Other Energy Charge and Other Fuel Cost Adjustor Charge, calculated as set forth in Exhibit A-4; plus

5. any Power Factor Adjustment pursuant to Section 2.2 hereof; plus,

6. any Demand Overrun Adjustment pursuant to Section 2.3 hereof; plus,

7. all taxes and/or assessments pursuant to Section 2.4 hereof, if any; plus

8. 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 the Agreement, including this Rate Schedule A, is attached to this Rate Schedule A as Exhibit A-6 and made a part hereof. Actual billings made by AEPCO to Member pursuant to Section 5.1 of the 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 charges set forth in Exhibits A-1 to Rate Schedules 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 charges as set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members do not provide revenues sufficient, but only sufficient, to satisfy AEPCO's Revenue Requirements from Class A Members, the Board of Directors of AEPCO shall establish new rates and new charges for electric service to Member pursuant to the procedures set forth in Section 5.6 of the Agreement and otherwise comply with those provisions pertaining to rates and the charges as set forth in Section 5 of the Agreement. Such new rates and charges established in conjunction with new rates and charges for all other Class A Members shall be submitted to the RUS and shall become effective unless they have been disapproved in writing by the RUS, and Exhibits A-1 (and other Exhibits, as may be applicable) to Rate Schedules A shall be modified to reflect such new rates and charges in effect.

3.2 Development of Cost of Service and Revenue Requirement.

AEPCO rates and the charges developed under this Rate Schedule A for charging Member and rates and charges for charging 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 proposed rates and charges based on such cost of service studies and Revenue Requirement are approved by the AEPCO Board of Directors. 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., data shall be 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 all Class A Members shall be developed pursuant 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, or energy as set forth in Exhibit A-2 and depicted in Exhibit A-3 hereto.

3.4 Development of Rates, Charges, and Billing Determinants.

Once the components of fixed, O&M, and energy of AEPCO's Revenue Requirement from All Class A Members are determined pursuant to Section 3.2, and all expenses are classified pursuant to Section 3.3, the rates and charges for electric service pursuant to the Agreement shall be determined in accordance with Exhibit A-2. The billing determinants for Member's Fixed Charge and Member's O&M Charge shall be the ACP as specified in Section 3.5 below. The billing determinants for the energy rates shall be determined pursuant to Exhibit A-4 and as set forth in Section 5.4 of Exhibit A-2.

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 and O&M Charge for Member. Appendix B to Exhibit A-5 to this Rate Schedule A identifies AEPCO Resources in the Dispatch Pool as well as the Allocated Capacity (AC) for Member.

Exhibit A-1 to Rate Schedule A
Partial Requirements Member
Rates and Fixed Charge
(Effective as of Agreement Date)

Fixed Charge	$ per month *
O&M Charge	$ per month *
Energy Rates:	
Base Energy Rate	$_______ per kWh * of base resources used during the billing period.
Other Energy Rate	$_______ per kWh * of other resources used during the billing period.
Power Cost Adjustor Rate for FPPCA:	
Base Resources	$_______ per kWh *
Other Resources	$_______ per kWh *

*based on test year data with pro forma adjustments as approved by the ACC.

Partial Requirements Members
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 charges applicable for AEPCO Resources in which Member has an ACP. This methodology shall be applied to AEPCO expenses and revenues described herein which are maintained under the RUS 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 charges 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 Member through charging the rates and charges developed pursuant to the Agreement, plus (ii) revenues to be recovered from other Partial Requirements Members through rates and charges pursuant to their Partial Requirements Capacity and Energy Agreements; plus (iii) revenues to be recovered from the All Requirements Members through rates and charges pursuant to their Existing Wholesale Power Contracts, plus (iv) 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 RUS 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 under the RUS Uniform System of Accounts by AEPCO 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 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 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 classified as either: (a) Credits-F, (b) Credits-O, or (c) Credits-E.

Margins shall be classified and assigned to the fixed category.

2.2 Depiction.

The expense and revenue accounts and their classification into fixed, O&M and energy 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 charges attributable to electric service under the 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 Charge 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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Account 403	(Depreciation & Amortization Expense),
Account 408	(Ad Valorem Taxes),
Accounts 427-428	(Interest on Long Term Debt, Interest Charged to Construction, 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),
Plus 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 Accts 447-456	(Credits – F) which include: (a) a portion of the revenues from Power Sales Resources, consisting of total Power Sales Resources' revenues less Power Sales Resources' energy revenues, to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such revenues; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services, but excluding the sales of power in subparagraph a above; such portion to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such net revenues.

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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

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), and
Accounts 920-923	(Administrative & General I-O only),
Account 924	(Administrative & General II-O only),
Accounts 925-926	(Administrative & General III-O only), and
Accounts 927-932	(Administrative & General I-O only).
Less Accounts 447-456	(Credits-O) consisting of: (a) Scheduling Revenues - The scheduling revenues resulting from providing scheduling and trading services for customers other than Class A Members of AEPCO, excluding energy-related revenues, to be credited in an amount equal to the product of the total of such revenues multiplied by the ACP of the Member; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services; such portion to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such net revenues.

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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Accounts 501 and 547	(Fuel-E only),
Accounts 555	(Purchased Power-E only),
Account 565	(Wheeling Power-E only),
Accounts 920-923	(Administrative & General I-E only),
Account 924	(Administrative & General II-E only),
Accounts 925-926	(Administrative & General III-E only), and
Accounts 927-932	(Administrative & General I-E only),
Less Accounts 447-456	(Credits-E only).

5.0 MEMBER RATES AND CHARGES:

5.1 Elements.

The rates and charges for electric service under the Agreement to Member shall consist of (a) the Fixed Charge, composed of an appropriate allocated fixed capacity component, including a margin, (b) an O&M Charge, (c) Base Energy Rate, and (d) Other Energy Rate.

5.2 Fixed Charge.

The monthly Fixed Charge for Member, stated in dollars, shall equal: the quotient of (a) the product of (i) 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 caused by failures of Class A Members to meet their portion of AEPCO's Revenue Requirement, multiplied by (ii) the ACP of Member, (b) divided by twelve (12) to convert to a monthly charge.

5.3 O&M Charge.

The O&M Charge for Member shall be equal to the quotient of (a) the product of (i) the annual test year O&M component as calculated in Section 3.3 of this Exhibit A-2, multiplied by (ii) the ACP of Member, (b) divided by twelve (12) to convert to a monthly charge.

5.4 Base Energy Rate and Other Energy Rate.

The Base Energy Rate and Other Energy Rate for Member shall be established based on the methodology contained in Exhibit A-4, and shall together equal the energy component comprised of the expenses, less revenue credits as identified in Section 4.0 of this Exhibit A-2 and calculated pursuant to the methodology in Exhibit A-4, divided by the aggregate test year energy billing units (stated in kWh) developed pursuant to Exhibit A-4 in the cost of service study for the Class A Members, adjusted for known and measurable changes.

6.0 REVENUE SHORTFALLS:

Any deficiencies or shortfalls in collections of AEPCO's Revenue Requirement from Class A Members will be recovered through appropriate adjustments to: (a) the O&M Charge, or (b) the margin included in the Fixed Charge. An adjustment will be made to the O&M Charge 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 Charge 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 charges shall be based on Schedules or on metered data at the Delivery Points. 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 and charges 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.

Partial Requirements Members
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	
	Maintenance:			

[1]All fuel related costs are assigned to the energy classification, except for 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)
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]
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]

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[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)
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		
447-456	Operating Revenues from Other Sources – Credit	X(7)	X(7)	X(7)
	Margin Component	X		

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

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

7Excluding revenue from Power Sales Resources, revenue from sources other than AEPCO's Class A Members shall be credits to the Fixed component and to the O&M component in amounts proportionate to Fixed Revenue Requirements and O&M Revenue Requirements.

Exhibit A-4 to Rate Schedule A
Determination of Billing Units, Energy Rates and Energy Charges Using Cost Causation Principles

1. INTRODUCTION:

This Exhibit A-4 sets forth the methodology for the determination of energy billing units, energy rates and energy charges for each of AEPCO's Class A Members using cost causation allocation principles.

2. DEFINITIONS:

The following terms are used in this Exhibit and its Appendices.

"ARM Energy Cost Responsibility Share" or "ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future

Scheduling Hour; and for each Billing Unit Entity having a percentage interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Caacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by its (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the

entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"CARM" or "Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources and in S&G PPA, as applicable to each All Requirements Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A to the ARM Wholesale Power Contracts.

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.

"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate" shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sales Price" shall mean, for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy.

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G PPA Billing Energy and Supplemental Billing Energy.

"Federal Hydro Power Agreement(s)" shall mean 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 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).

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Network Loss Factor" shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period, as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Sales Resource Demand Revenues" shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Power Sales Resource Energy Revenue" shall mean, for a billing period the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"PRM" shall mean a Partial Requirement Member.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as an S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean, for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made for a period of less than a year to serve load of CARM or a Planning Contract Member in excess of CARM's or the Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by

AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Tariff" shall mean, at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sales" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported as an economy sale by AEPCO to RUS Uniform System of Accounts Number 447.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean, for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

3. <u>BILLING UNIT PROGRAM METHODOLOGY</u>:

The Billing Unit Program shall be assembled and maintained to reflect AEPCO's economic dispatch philosophy and priority as further set forth in Schedule B to the Partial Requirements Capacity and Energy Agreements. The Parties have divided and defined AEPCO Resources based on the respective interests therein as assigned under the Billing Unit Program, the definition of which is set forth in Appendix A to this Exhibit A-4, attached hereto and a part hereof.

The Billing Unit Program is established hereunder to account for hourly energy, separately for Daytime and Nighttime hours, first, for each Billing Unit Entity, its Minimum Other Capacity, then for each Billing Unit Entity having an ACP in S&G PPA or an interest in Supplemental Purchase, from its interests in Available Supplemental Capacity and Available S&G PPA Capacity (as dispatched by AEPCO under governing purchase contracts), then for each Billing Unit Entity its Available Base Capacity and finally its remaining Available Other Capacity. These hourly amounts for each Billing Unit Entity are assigned first to any Directed Sales of a Member* CA, to the loads of the CARM and Member* CA and to each Member*'s Total Schedule, but only to the extent required by the load of the CARM, by the Directed Sales and load of the Member* CA and by the Member*'s Total Schedule.

If a Billing Unit Entity has load or a Schedule that is not satisfied by its Available Base Capacity, Available Supplemental Capacity and Available S&G PPA Capacity, the Billing Unit Entity shall be assigned S&G And Supplemental Transfers and Base Transfers from other Billing Unit Entities' Excess S&G And Supplemental Capacity and Excess Base Capacity pursuant to the Billing Unit Program, proportionately based on the need of each Billing Unit Entity for Other Resources to the need of all Billing Unit Entities for Other Resources. To the extent a Billing Unit Entity still has load or a Schedule that is not satisfied, energy shall be assigned to it from its Available Other Capacity.

On the other hand, if a Billing Unit Entity has any Excess S&G And Supplemental Capacity or Excess Base Capacity, it shall be assigned pursuant to the Billing Unit Program proportionately based on available excess as S&G And Supplemental Transfers and Base Transfers. Then any Post-Transfer Base Capacity shall be assigned pursuant to the Billing Unit Program proportionately based on the amounts of such excess in the hour as Base Economy Sales, if any, or shall be assigned as Base Energy Mismatch or Other Energy Mismatch, as applicable.

Finally pursuant to the Billing Unit Program, the Other Economy Sales accumulated for the billing period will be allocated to each Billing Unit Entity proportionately based on each Billing Unit Entity's proportionate share of the billing period's accumulated totals of Post-Transfer S&G And Supplemental Capacity, each Member*'s Other Billing Energy, CARM Other Billing Energy, and each Member* CA's Other Billing Energy.

The Parties agree that all such assignments and allocations represent sale and purchase transactions to and from the Dispatch Pool Resources for which each Billing Unit Entity shall be credited or billed pursuant to Section 4 below.

Base Energy Mismatch and Other Energy Mismatch may occur due to operating conditions experienced during any billing period when the assignment and allocation of energy pursuant to the Billing Unit Program may be more or less than the amount of energy actually produced by the Dispatch Pool Resources; the causes of which may include, but are not limited to: (i) energy received from resources of third parties or provided to third parties for losses repayment; (ii) variations between loss accounting and actual hourly losses occurring on the system; (iii) energy interchange with other utilities; (iv) metering errors; and (v) inadvertent flows between AEPCO and its Balancing Authority. The Billing Unit Program shall compute for each billing period the total net Base Energy Mismatch and total Other Energy Mismatch and assign a credit or charge for the period, as applicable, which shall be recovered through the appropriate FPPCA.

The initial logic flow diagram of the Billing Unit Program is attached hereto as Appendices B through D to this Exhibit A-4 and is a part hereof. The Billing Unit Program shall be the sole and exclusive method for billing purposes of assigning energy billing units from Dispatch Pool Resources to Billing Unit Entities, and may only be modified by a written amendment agreed to by the CEOs of all Billing Unit Entities.

4. METHODOLOGY FOR DETERMINING TARIFF ENERGY RATES:

The following describes the method AEPCO shall use to formulate the Base Energy Rate and the Other Energy Rate.

4.1 Tariff Base Energy Rate.

The Base Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Base Energy Cost of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credits, Base Economy Sales Cost and Remaining Base Energy Cost, by (ii) each Billing Unit Entity's Base Billing Energy of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.1.1 The Base Energy Rate of each All Requirements Member shall be the same as the Base Energy Rate for CARM.

4.1.2 The Base Power Cost Adjustor Base for each All Requirements Member shall be the same as the Base Power Cost Adjustor Base determined for CARM.

4.1.3 The Base Billing Energy of each All Requirements Member shall be the product of (i) the Base Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

4.2 Tariff Other Energy Rate.

The Other Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Total Other Energy Cost of each Billing Unit Entity of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's applicable Base Transfer Purchase Cost, S&G PPA Energy Cost, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Transfer Sales Credit, Other Economy Sales Credit and its share of Base Mismatch Energy Credit, Base Mismatch Energy Charge, Other Mismatch Energy Credit, Other Mismatch Energy Charge and, if any, by (ii) the Total Other Billing Energy as applicable to each Billing Unit Entity for the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.2.1 The Other Energy Rate of each All Requirements Member shall be the same as the Other Energy Rate for CARM.

4.2.2 The Other Power Cost Adjustor Base for each All Requirements Member shall be the same as the Other Power Cost Adjustor Base determined for CARM.

4.2.3 The Total Other Billing Energy of each All Requirements Member shall be the product of (i) the Total Other Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

5. DETERMINING BASE AND OTHER ENERGY CHARGES:

5.1 Each billing period, AEPCO shall charge each Billing Unit Entity a Base Energy Charge, Base Fuel Adjustor Charge, Total Other Energy Charge and Other Fuel Adjustor Charge as defined in the Tariff. For each billing period, AEPCO shall compute each Billing Unit Entity's Base Over or Under Collection and Other Over or Under Collection for each billing period, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

5.1.1 Base Energy Charge: The Base Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Energy Rate as set forth in the Tariff.

5.1.2 Base Fuel Adjustor Charge: The Base Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.3 Base Over or Under Collection: The Base Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Base Adjustor Per Unit Cost and (ii) the sum of the Base Power Cost Adjustor Base plus the Base Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Base Billing Energy of each Billing Unit Entity for that period.

5.1.4 Other Energy Charge: The Other Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Energy Rate as set forth in the Tariff.

5.1.5 Other Fuel Adjustor Charge: The Other Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.6 Other Over or Under Collection: The Other Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Other Adjustor Per Unit Cost and (ii) the sum of the Other Power Cost Adjustor Base plus the Other Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Total Other Billing Energy of each Billing Unit Entity for that period.

6. ENERGY COST ACCOUNTING PROCESS:

The following describes the method of the Energy Cost Accounting Process (ECAP) AEPCO shall use to formulate for each billing period each Billing Unit Entity's Base Energy Cost, Base Fuel Adjustor Cost, Total Other Energy Cost and Other Fuel Adjustor Cost, from which AEPCO shall compute each Billing Unit Entity's Base Adjustor Per Unit Cost and Other Adjustor Per Unit Cost for the billing period, which shall be used to calculate for each billing period (i) Base Over and Under Collection and Other Over or Under Collection for such energy and (ii) fuel adjustor costs, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

The initial logic flow diagram of the ECAP is attached hereto as Appendices E and F to this Exhibit A-4 and is a part hereof.

6.1 Formulating Base Energy Cost.

For each billing period, the ECAP shall first compute the Coal Energy Cost and use it to calculate the Coal Energy Rate based on the Coal Energy Generated.

The ECAP shall then use Base Transfer for the billing period to compute, separately for Daytime and Nighttime, Base Transfer Sales Credit based on the Coal Energy Rate, and use Base Transfer Billing Energy to compute, separately for Daytime and Nighttime, Base Transfer Energy Cost, based on the Economy Purchase Rate. Using the billing units determined for the billing period pursuant to the Billing Unit Program, the Base Transfer Sales Credits and Base Transfer Energy Cost will then be allocated to each Billing Unit Entity. Similarly, the ECAP shall use Base Economy Sales for the billing period to compute Base Economy Sales Credits (separately for Daytime and Nighttime) and Base Economy Sales Cost, based on Economy Sales Price (separately for Daytime and Nighttime) and the Coal Energy rate, respectively, and shall then allocate such Base Economy Sales Credits and Base Economy Sales Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall then calculate Base Billing Energy Cost for the billing period, by adding Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchases and Power Sales Resource Energy Revenue, and shall allocate such

Base Billing Energy Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

Finally, the ECAP shall calculate for the billing period each Billing Unit Entity's (i) Base Energy Cost, which shall be the total of the Billing Unit Entity's Base Transfer Sales Credit, Base Transfer Energy Cost, Base Economy Sales Credit, Base Economy Sales Cost and Remaining Base Energy Cost, and (ii) Base Average Energy Rate, which shall be the quotient of the Billing Unit Entity's Base Energy Cost divided by its Base Billing Energy determined pursuant to the billing units assigned by the Billing Unit Program.

6.2 Formulating Base Adjustor Per Unit Cost.

The ECAP shall allocate to each Billing Unit Entity based on the Billing Unit Entity's Allocated Capacity Percentage the billing period's total Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Cost, which allocation ECAP shall add to the Billing Unit Entity's Base Energy Cost to formulate the Billing Unit Entity's Base Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Base Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Base Fuel Adjustor Cost divided by its Base Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.3 Formulating Base Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Base Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Base Adjustor Per Unit Cost less the sum of (i) its Base Power Cost Adjustor Base and (ii) its Base Power Cost Adjustor Rate, and (b) Base Over or Under Collection, which shall be the product of the Billing Unit Entity's Base Incremental Unit Cost multiplied by its Base Billing Energy. Each Billing Unit Entity's Base Over or Under Collection shall then be added to the balance in its Base Fuel Bank.

6.4 Formulating Total Other Energy Cost.

Each billing period, the ECAP shall use the Economy Purchase Rate (separately for Daytime and Nighttime) to determine S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit based on S&G And Supplemental Transfer. Such S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit shall then be allocated as appropriate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall allocate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program (i) the billing period's Other Economy Sales

Credit as appropriate based on the Billing Unit Entity's proportionate share of the billing period's Post-Transfer S&G And Supplemental Capacity and Other Billing Energy, and (ii) the billing period's Other Energy Cost based on the Billing Unit Entity's Other Billing Energy. The ECAP shall then assign to each Billing Unit Entity pursuant to the Billing Unit Entity's ACP and/or interest in and the billing units assigned by the Billing Unit Program, as applicable, the Billing Unit Entity's S&G PPA Energy Charge, Supplemental Energy Charge, Base Transfer Purchase Cost, Other Energy Cost, Directed Sales Credit, and its share of Base Mismatch Energy Credit, Base Mismatch Energy Cost, and Other Mismatch Energy Credit.

Finally, the ECAP shall determine for the billing period (i) each Billing Unit Entity's Total Other Energy Cost, which shall be equal to the sum of all the credits and costs allocated or assigned to the Billing Unit Entity as described in this Section 6.4, and (ii) each Billing Entity's Other Average Energy Rate, which shall be the quotient of its Total Other Energy Cost divided by its Total Other Billing Energy.

6.5 Formulating Other Adjustor Per Unit Cost.

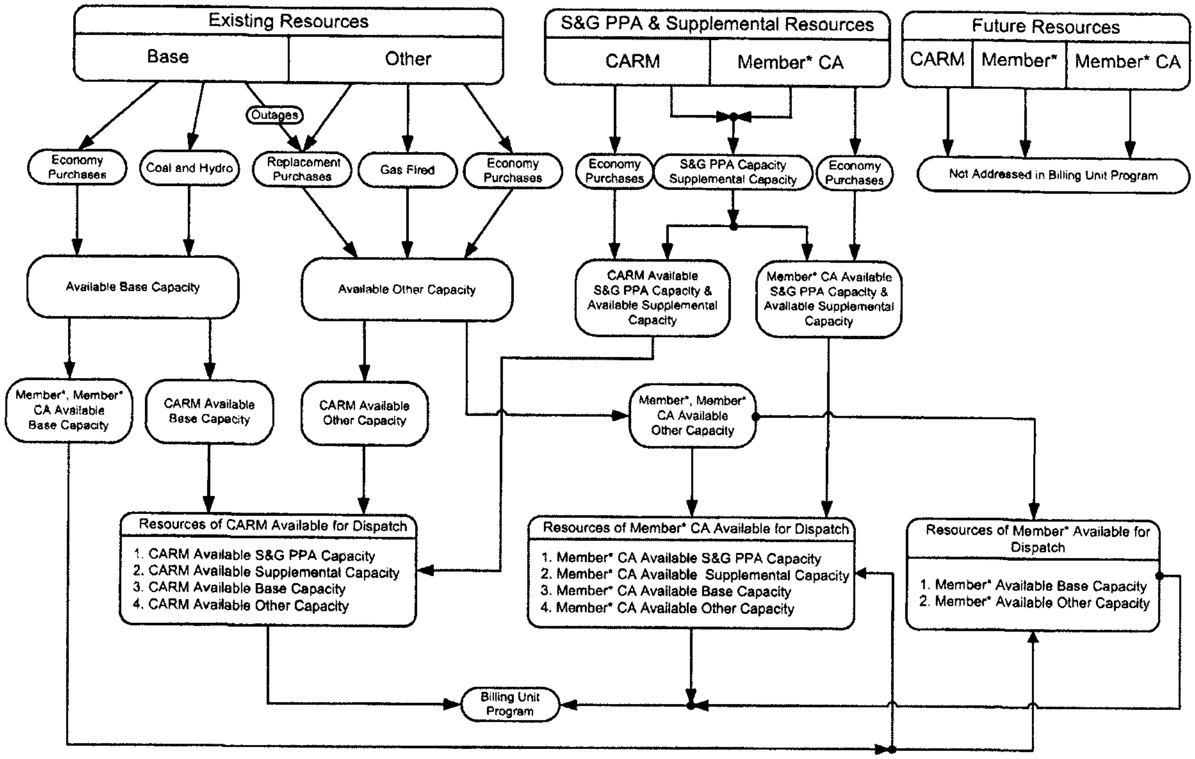
The ECAP shall allocate to each Billing Unit Entity the billing period's (i) total Other Transmission Wheeling Cost based on the Billing Unit Entity's Allocated Capacity Percentage, and (ii) S&G PPA Demand Charge, S&G PPA Wheeling Cost, Supplemental Demand Charge and Supplemental Wheeling Charge, pursuant to the Billing Unit Entity's ACP share or interest therein, if any. The ECAP shall then add such allocations to each Billing Unit Entity's Total Other Energy Cost to formulate the Billing Unit Entity's Other Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Other Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Other Fuel Adjustor Cost divided by its Total Other Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.6 Formulating Other Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Other Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Other Adjustor Per Unit Cost less the sum of (i) its Other Power Cost Adjustor Base, plus (ii) its Other Power Cost Adjustor Rate, and (b) Other Over or Under Collection, which shall be the product of the Billing Unit Entity's Other Incremental Unit Cost multiplied by its Other Billing Energy. Each Billing Unit Entity's Other Over or Under Collection shall then be added to the balance in its Other Fuel Bank.

Appendix A to Exhibit A-4 to Rate Schedule A: AEPCO Resources Definitions Flow Diagram



Appendix B Footnotes:

(1) Subroutine: CARM Post S&G And Supplemental Load is first assigned to CARM Minimum Other Capacity.
(1a) Subroutine: CARM Load is first assigned to CARM Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G and Supplemental Transfer Other Schedule or Post S&G And Supplemental Transfer Load.
(3) Subroutine: CARM Excess S&G And Supplemental Capacity is allocated as CARM S&G And Supplemental Transfers proportionately based on need to Member* Other Schedule and Member* CA Post Base Load, until such CARM Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule and Member* CA Post Base Load are satisfied.
(4) Subroutine: Member*, Member* CA Excess Base Capacity is allocated proportionately based on need to CARM and Member* CA Post-S&G And Supplemental TransferLoad and Member* Post-S&G And Supplmental Transfer Other Schedule until such Member*, Member* CA Excess Base Capacity is consumed, or until such CARM and Member* CA Post S&G and Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule are satisfied.
(5) Subroutine: CARM Excess Base Capacity is allocated proportionately based on need to Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G And Supplemental Transfer Load until such CARM Excess Base Capacity is consumed, or until Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G And Supplemental TransferLoad are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

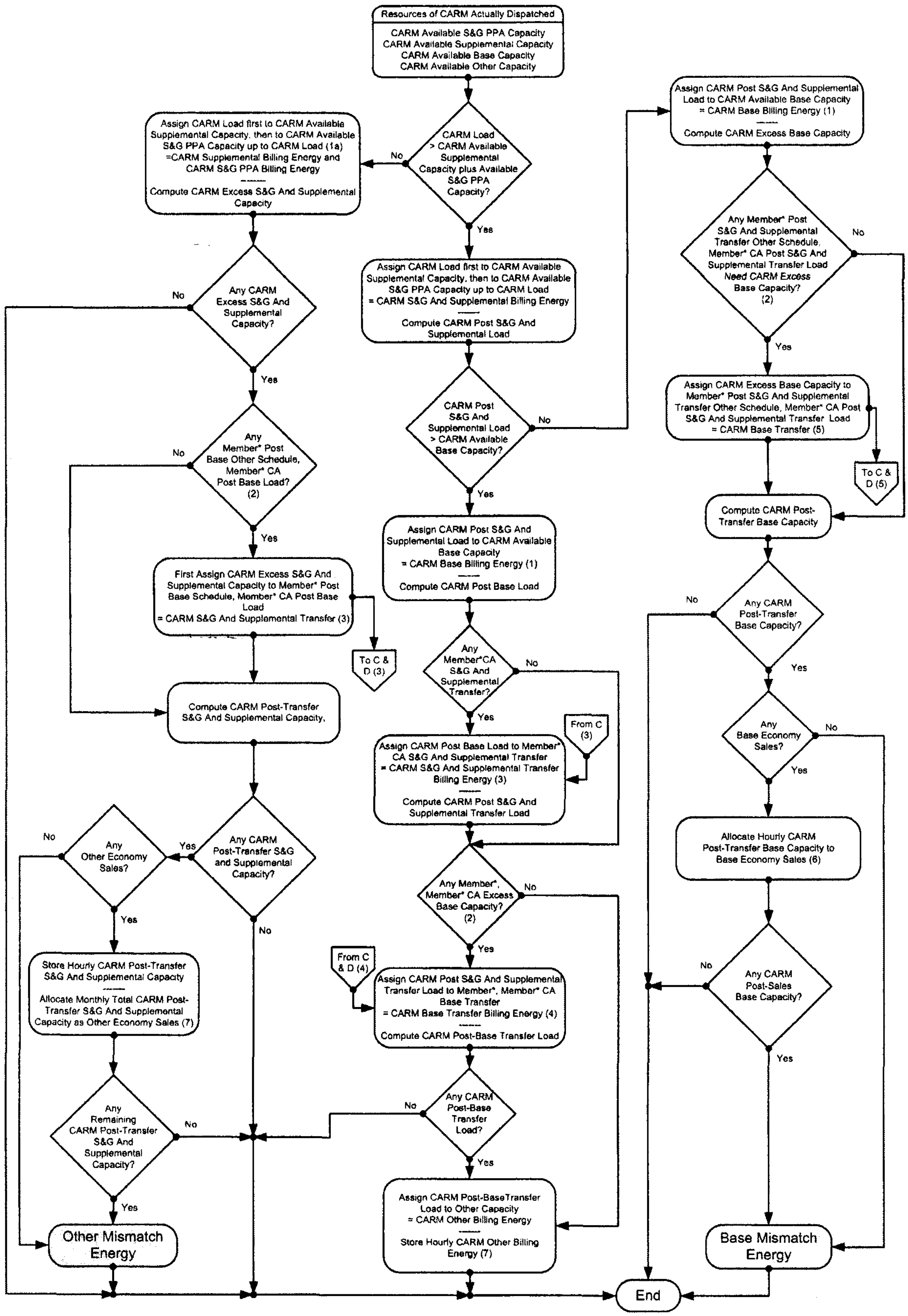
Appendix C Footnotes:

(1) Subroutine: Member* CA Post S&G And Supplemental Load is first assigned to Member* CA Minimum Other Capacity.
(1a) Subroutine: Member* CA Directed Sales and Load is first assigned to Member* CA Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA Excess S&G And Supplemental Capacity is allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: *Member*, CARM, and other Member** CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule *until such Member**, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* CA Excess Base Capacity is allocated proportionately based on need to Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

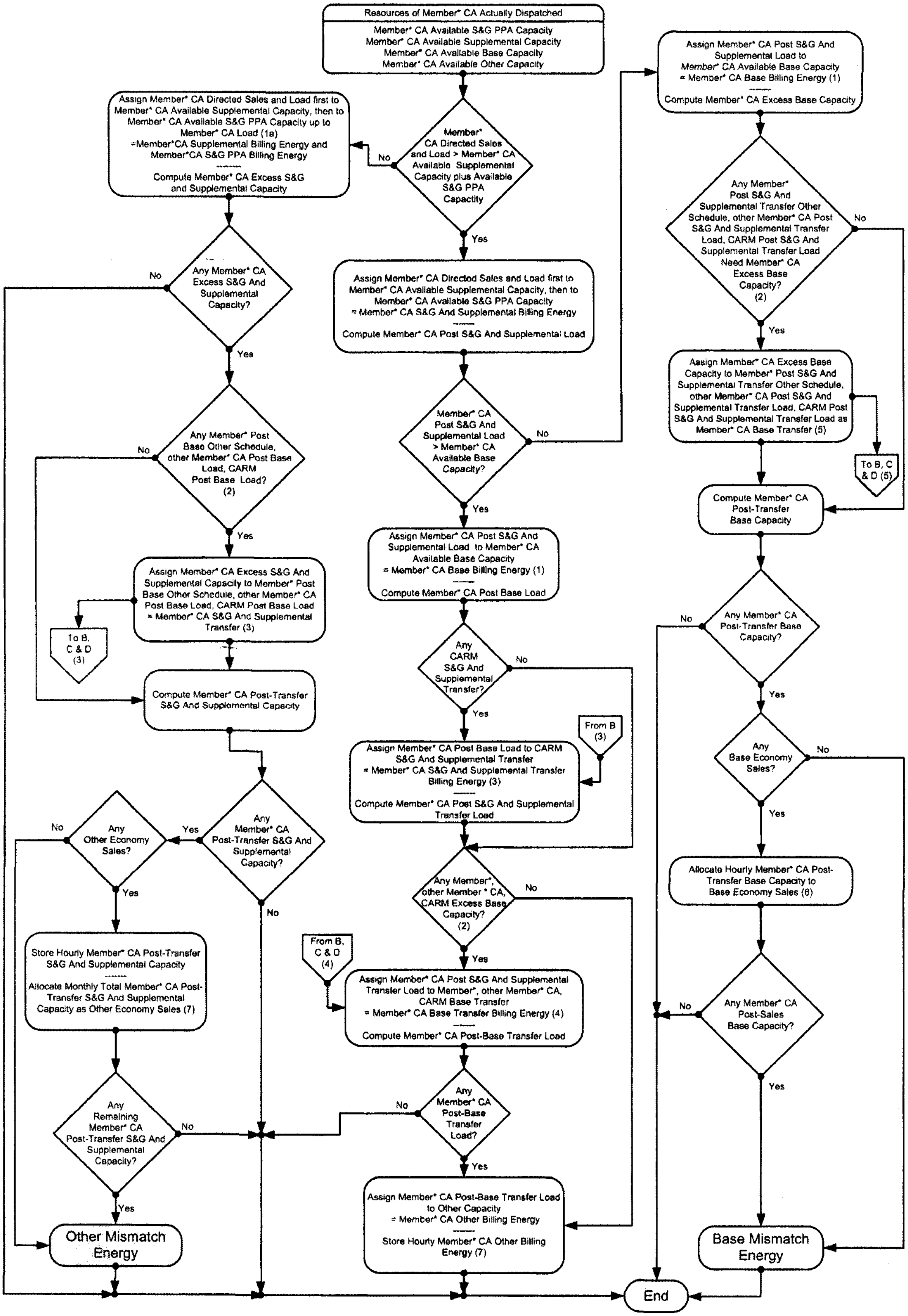
Appendix D Footnotes:

(1) Subroutine: Member* Base Schedule is first assigned to Member* Minimum Other Capacity.
(2) Subroutine: (2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA and CARM Excess S&G And Supplemental Capacity are allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Post Base Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* Excess Base Capacity is allocated proportionately based on need to each Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.
(8) No Partial Requirements Member with an interest in S&G PPA currently plans to operate outside the AEPCO pseudo-control area. In the event that a Partial Requirements Member with such an interest chooses to operate outside the AEPCO pseudo-control area in the future, the Appendix D flow chart for such a Member* will need to be modified.

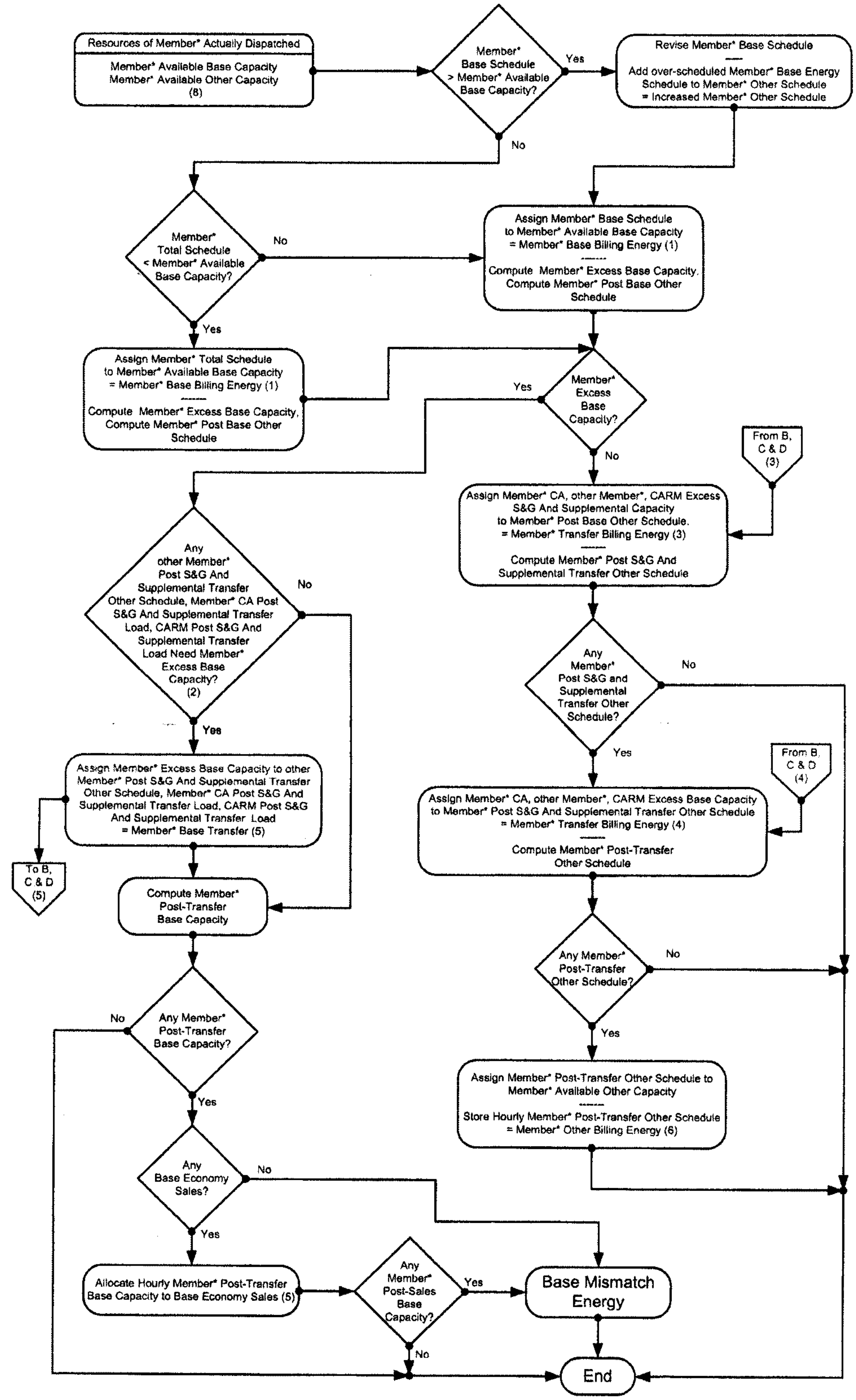
Appendix B to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
CARM Load Use of AEPCO Resources and Assignments as Additional and Base Transfers and AEPCO Third Party Sales



Appendix C to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* CA Load use of AEPCO Resources and Assignments as S&G PPA and Base Transfers and AEPCO Third Party Sales

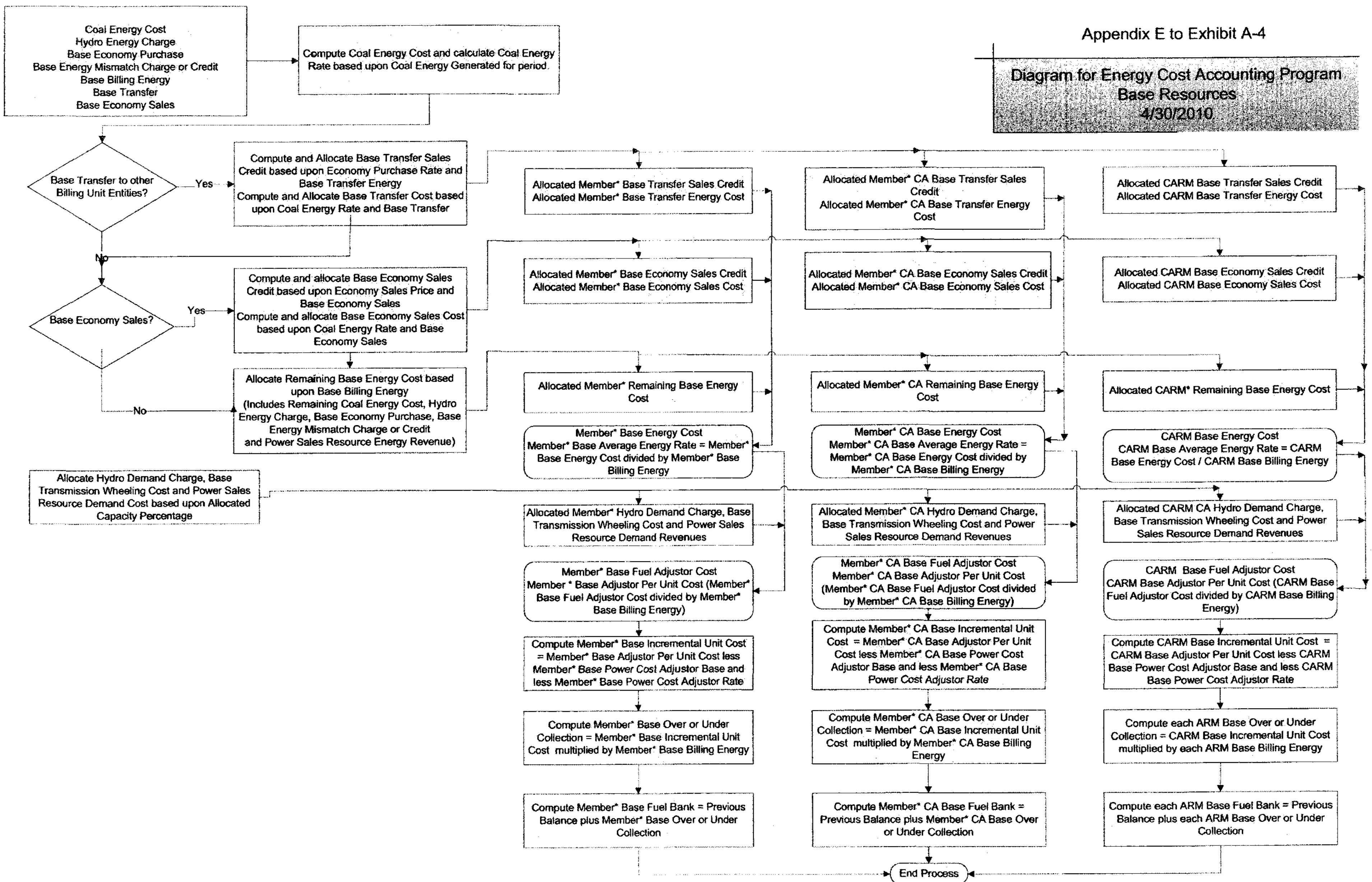


Appendix D to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* Use of AEPCO Resources and Assignments as Base Transfers and AEPCO Third Party Sales



Appendix E to Exhibit A-4

Diagram for Energy Cost Accounting Program
Base Resources
4/30/2010



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Appendix F to Exhibit A-4

Diagram for Energy Cost Accounting Program
Other Resources
4/30/2010

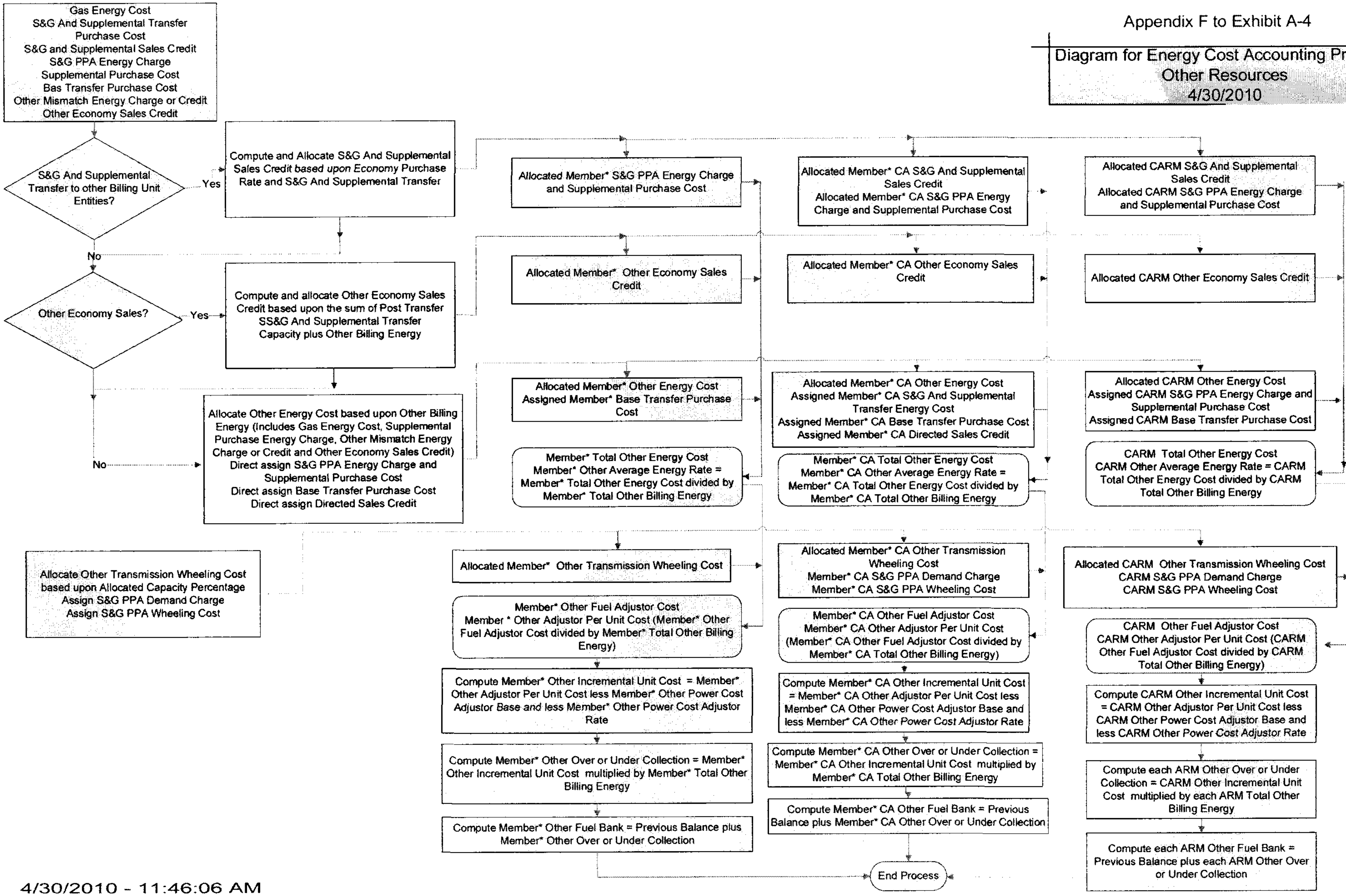

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Exhibit A-5 to Rate Schedule A
Allocated Capacity Percentages (ACP),
Allocated Capacity (AC)
and Reserves

ACP and AC DETERMINATION

An Allocated Capacity Percentage (ACP) was developed for Existing Resources as of the Effective Date for each Class A Member based on load forecasts from the 1996 Power Requirements Study (1996 PRS). The ACP in Existing Resources is used to calculate the Allocated Capacity (AC) for each Partial Requirements Member (PRM), and each All Requirements Member (ARM) in Existing Resources.

At the outset of AEPCO's restructuring, AEPCO, all AEPCO Class A Members, and RUS had approved the use of the 1996 PRS for planning purposes. AEPCO and its Class A Members agreed to the specific use of the 1996 PRS and forecast year 2000 as the basis for calculating the ACP in Existing Resources 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 in Existing Resources is summarized in Part A of Appendix A to this Exhibit A-5. The ACP calculation for Existing Resources utilized the forecasted year 2000 monthly coincident peaks of the Class A Members, which were obtained by multiplying: (a) each Member's forecasted monthly non-coincident peak as identified in the 1996 PRS, by (b) a historical three-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 an ARM in Existing Resources shall be used to determine its AC in Existing Resources in the event such ARM elects to become a Partial Requirements Member pursuant to the Conversion Agreement between the Class A Members and AEPCO dated August 1, 2001 (Conversion Agreement). The sum of the ACP's of the ARMs shall be the ACP of the Collective ARM (CARM) for purposes of Rate Schedule A to Existing Wholesale Power Contracts.

The monthly AC assigned to each PRM and the CARM from Existing Resources has been calculated by: (1) determining the capacity (in MW) of the generating units that comprise Existing Resources; (2) determining the Reserve percentage (described hereinafter) to be set aside from the generating units that comprise Existing Resources; (3) subtracting the Power Sales Resources as of the Closing Date of AEPCO's restructuring, including associated reserves and delivery losses attributable to such Power Sales: (4) further reducing the Existing Resource generating unit capacity for AEPCO generating unit reserves and delivery losses; (5) adding the monthly capacity from the Federal Hydro Power Agreements; and (6) multiplying such net capacity of Existing Resources by the ACP of each PRM and the CARM.

The AC in Existing Resources of each PRM and the CARM is further subdivided into Available Base Capacity and Available Other Capacity and shall be as shown on Appendix B to this Exhibit A-5. The Available Base Capacity of each PRM and the CARM shall be the respective

ACP shares of Base Resources after reduction for delivery losses. The Available Other Capacity shall be the respective ACP share of Other Resources after reduction for reserves and delivery losses.

For AEPCO Resources added and not included as Existing Resources (currently the S&G PPA Resource), each Class A Member participating in the added Resource accepts an ACP in that Resource pursuant to its agreement with AEPCO. That ACP shall be derived by a method determined by AEPCO based on adequacy of Resources to meet the forecasted loads of participating Class A Members under a method adopted by the AEPCO Board of Directors prior to AEPCO's commitment to the added Resource. Each participating Class A Member's AC in the Resource shall be the product of its ACP in the added Resource multiplied by the capacity of the Resource after reduction for delivery losses, and if required, reserves.

The ACP of the participating Class A Members as a PRM or as a part of CARM in an added Resource shall be set forth in a revision to Appendix A to this Exhibit A-5. The AC of such participating Class A Members as a PRM and as the CARM in an added Resource shall be set forth in a revision to Appendix B to this Exhibit A-5. Both the Appendices A and B as so revised shall be provided by AEPCO to all Class A Members at the time of the commitment by AEPCO to the added Resource. No such revision of Appendices A and B shall affect the ACP and AC of the non-participating Class A Members.

The ACP for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix A to this Exhibit A-5, and the AC for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix B to this Exhibit A-5. Neither the ACP nor the AC of the S&G PPA Resource shall be changed absent the agreement of TRICO and the participating ARMs that comprise the CARM.

RESERVE PERCENTAGE DETERMINATION:

In accordance with WECC reliability criteria, AEPCO is required to have in reserve access to generation sufficient to cover AEPCO's largest single generating unit hazard. AEPCO's largest single generating hazard consists of an outage of 188 MW of coal-fired steam generating unit capacity (which includes 13 MW of spinning reserve capacity), and after the first hour of such an outage includes an additional 29 MW, which 29 MW is subject to call from AEPCO by other members of the Southwest Reserve Sharing Group pursuant to the Southwest Reserve Sharing Group agreement, to which AEPCO is party. For the first hour of the outage, AEPCO currently relies on the generating support of other members of the Southwest Reserve Sharing Group to cover AEPCO's largest single generating unit outage.

Based on the above, AEPCO shall seek to reduce the MW of generation that would be required to be set aside for coverage of AEPCO's largest single generating unit by purchasing reserved transmission capacity from Southwest Transmission Cooperative, Inc., Mohave Electric Cooperative, Inc. and others as available, in that order of priority. AEPCO shall seek such transmission capacity in amounts necessary to realize AEPCO's reserve generating unit capacity percentage as 6.7% from 2011 through 2020, and 7.0% for the period from 2021 through 2035, which are the reserve capacity percentages as set forth in Appendix B to this Exhibit A-5. AEPCO and SWTC shall annually agree to a plan for AEPCO to follow to seek to obtain such transmission capacity, which shall be provided to the Class A Members for review. To the

extent AEPCO obtains transmission capacity in accordance with the established plan, the Class A Members agree that AEPCO shall include the costs of such transmission capacity in AEPCO's rates to such Class A Members.

In the event AEPCO is unsuccessful or less than fully successful in its attempts to timely purchase such reserved transmission capacity in advance of the start of any calendar year, AEPCO shall have the unilateral right to increase the reserve capacity percentage of Appendix B to this Exhibit A-5 for such calendar year. In such event, AEPCO shall provide, timely in advance of the start of such calendar year, a revised Appendix B to this Exhibit A for such calendar year that shows the effect of such increased reserve capacity percentage on the Available Base Capacity and Available Other Capacity of each PRM and the CARM. AEPCO and the Class A Members shall use such revised Available Base Capacity and Available Other Capacity for the purposes of Exhibit A-4 in the affected calendar year.

Appendix A to Exhibit A-5

Schedule of Allocated Capacity Percentages

A. The schedule and calculation of the Allocated Capacity Percentages (ACP) for AEPCO Existing Resources existing as of August 1, 2001 (consisting of Existing Resources as set forth in Appendix B to Exhibit A-5) is shown below:

		Allocated Capacity Percentage						
		1996 PRS Coincident Peak Demand Forecast – MW						
Col.		1	2	3	4	5	6	7
Ln.	Year 2000	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
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	ACP	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

B. The Allocated Capacity Percentages (ACP's) for the S&G PPA I Resource consisting of the South Point and Griffth PPAs is 0% for both MEC and SSVEC. For the remaining Class A Members and the CARM, the resulting ACP's for the S&G PPA Resource are as follows:

Allocated Capacity %	Anza	DVEC	GCEC	CARM	TRICO	Total
	0.1%	0.1%	3.0%	3.2%	96.8%	100%

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2011

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	15.0	15.0	15.0	15.0	15.0	15.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources			8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves	(4)	2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity			534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP		21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP		35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP		31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves	(5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves			11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members			36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	48.8	48.8	48.8	48.8	48.8	48.8	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	47.2	47.2	47.2	47.2	47.2	47.2	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total AC			109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total AC			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity	(8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity	(8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity	(8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base		100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total Available Capacity			109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total Available Capacity			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9

Notes:
(1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours.
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2012

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	5.0	5.0	5.0	5.0	5.0	5.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources			8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves (4)		2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity			534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP		21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP		35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP		31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves	(5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves			11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members			36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	58.6	58.6	58.6	58.6	58.6	58.6	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	1.9	1.9	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	56.7	56.7	56.7	56.7	56.7	56.7	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total AC			109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total AC			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity	(8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity	(8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity	(8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base		100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total Available Capacity			109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total Available Capacity			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9

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Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match *totall reserves required* of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2013

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves (4)		2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	70.0	70.0	70.0	70.0	70.0	70.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	68.4	68.4	68.4	68.4	68.4	68.4	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	66.2	66.2	66.2	66.2	66.2	66.2	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	607.9	608.1	609.0	608.6	607.6	597.1	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.7	191.6	191.7	191.8	192.1	192.0	191.6	187.9	187.9	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.9	539.3	608.0	608.2	609.0	608.7	607.6	597.2	528.8	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2014

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power	(7)		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power	(7)		0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	78.2	78.2	78.2	78.2	78.2	78.2	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	75.7	75.7	75.7	75.7	75.7	75.7	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes *are implemented to such loss factors pursuant* to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2015 thru 2020

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			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 S&G PPA Resources			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 After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(7)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(7)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(7)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(7)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity	(7)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0

Notes:
(1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2021 thru 2035

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-2			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-3			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Existing Resource Units			388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			406.9	406.9	411.8	417.3	417.4	417.7	418.6	418.2	417.2	406.7	406.7	406.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Remaining Reserve Requrement (MW)			27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Reserve Requrement (% of Unit Cap)	(3)		7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Power Sales Resources MW														
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
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Less Member Losses after Reserves	(4)	2.31%	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Net Existing Resource Unit Capacity			379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			398.6	398.6	403.5	409.0	409.1	409.4	410.3	409.9	408.9	398.4	398.4	398.6
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	45.4	45.4	46.0	46.6	46.6	46.7	46.8	46.7	46.6	45.4	45.4	45.4
TRICO Existing Resource @ ACP		21.1%	84.1	84.1	85.1	86.3	86.3	86.4	86.6	86.5	86.3	84.1	84.1	84.1
MEC Existing Resource @ ACP		35.8%	142.7	142.7	144.4	146.4	146.4	146.6	146.9	146.7	146.4	142.6	142.6	142.7
SSVEC Existing Resource @ ACP		31.7%	126.4	126.3	127.9	129.6	129.7	129.8	130.1	129.9	129.6	126.3	126.3	126.3
Member Reserve Shares (MW)														
CARM Reserves			3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
TRICO Reserves			5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
MEC Reserves	(5)		9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
SSVEC Reserves			8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Total Reserves Req'd of Class A Members			27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			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 S&G PPA Resources			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 After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total AC			78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total AC			133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total AC			121.8	121.7	123.3	125.0	125.1	125.2	125.6	125.3	125.0	121.7	121.7	121.7
Total			375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.1	41.1	41.7	42.3	42.3	42.4	42.5	42.4	42.3	41.1	41.1	41.1
TRICO Available Base Capacity	(7)	21.1%	76.1	76.1	77.1	78.3	78.3	78.4	78.6	78.5	78.3	76.1	76.1	76.1
MEC Available Base Capacity	(7)	35.8%	129.2	129.2	130.9	132.9	132.9	133.1	133.4	133.2	132.9	129.1	129.1	129.2
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.3	115.9	117.6	117.7	117.8	118.1	117.9	117.6	114.3	114.3	114.3
Subtotal Base		100.0%	360.8	360.7	365.6	371.1	371.2	371.7	372.6	372.0	371.1	360.6	360.6	360.7
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
TRICO Available Other Capacity	(7)	21.1%	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
MEC Available Other Capacity	(7)	35.8%	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
SSVEC Available Other Capacity	(7)	31.7%	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Subtotal Available Other Cap			14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total Available Capacity			78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total Available Capacity			133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total Available Capacity			121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total			375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5

Notes:
(1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totali reserves required of Class A members.
(6) Credit for Operating Reserve contribution from *EuroFresh generation* controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

Exhibit A-6: Sample Bill

INVOICE

To: Member *
Address
City, AZ

'ATTN:

Member * ACP %

DATE: February 10, 2011

January, 2011				
				Total $
Fixed Charge				
O&M Charge				
		kwh	$/kwh	Total $
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
Minimum Other Capacity Charge				
	DOAF			
Demand Overrun Adjustment	%			
Overrun Energy Charge				
	mkW	12MORA		
Power Factor Adjustor				
ACC Gross Operating Revenue Assessment				

Exhibit A-6: Sample Data for Bill
Member * 1

	Monthly MWH
Base Billing Energy	
Base Economy Purchases	
Off-peak	
On-Peak	
Base Transfer delivered	
Off-peak	
On-Peak	
Base Economy Sales credits	
Off-peak	
On-Peak	
Base Mismatch Energy	
Other Billing Energy	
Off-peak	
On-Peak	
Supplemental Transfer Billing Energy received	
Off-peak	
On-Peak	
S&G PPA Transfer Billing Energy received	
Off-peak	
On-Peak	
Base Transfer Billing Energy received	
Off-peak	
On-Peak	
Total Other Energy	
Off-peak	
On-Peak	
Other Mismatch Energy	
Other Ecomony Sales credits	

Exhibit A-6: Sample Bill

INVOICE

To: Member * CA
Address
City, AZ

'ATTN:

Member * CA ACP %

DATE: February 10, 2011

January, 2011				
				Total $
Fixed Charge				
O&M Charge				
		kwh	$/kwh	Total $
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Supplemental Billing Energy				
Supplemental Billing Energy Fuel Adjustor				
S&G PPA Billing Energy				
S&G PPA Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
Minimum Other Capacity Charge				
	DOAF			
Demand Overrun Adjustment	%			
Overrun Energy Charge				
	mkW	12MORA		
Power Factor Adjustor				

SCHEDULE B
TO PARTIAL REQUIREMENTS AGREEMENTS
Dated May 11, 2010
PRM RIGHTS, ABILITIES, AND CONSTRAINTS ASSOCIATED WITH ENERGY FROM AEPCO RESOURCES

1. INTRODUCTION

The primary purpose of this Schedule B is to define how a Partial Requirements Member (PRM) will access its entitlement to energy available from its AC in AEPCO Resources, such energy purchased pursuant to the Partial Requirements Capacity and Energy Agreement between Arizona Electric Power Cooperative, Inc. (AEPCO) and Member (Agreement) at the energy rates set forth in Exhibit A-1 to Rate Schedule A. This Schedule B defines available AEPCO Resources and the minimum capacity requirements for such resources, and how a PRM will schedule energy from AEPCO Resources in a manner consistent with such minimums and the Cost Causation principles upon which the energy rates are determined pursuant to Exhibit A-4 to Rate Schedule A.

Also recognized in this Schedule B is that the energy available for sale to a PRM at the energy rates set forth in Rate Schedule A can from time to time be a function of operating characteristics and limitations associated with the AEPCO Resources.

In addition, this Schedule B specifies the methodology pursuant to which additional charges shall be made by AEPCO to a PRM in the event that: (1) a PRM requires energy from AEPCO Resources that is in excess of the energy available to the PRM associated with its AC in AEPCO Resources; or (2) a PRM does not take its required minimum capacity and energy from AEPCO Resources because the PRM has used energy from other sources that displaces the use of such minimum energy from AEPCO Resources. Such additional charges shall be billed to the PRM pursuant to Rate Schedule A.

2. 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" shall mean Allocated Capacity.

"AEPCO Federal Hydro Power Capacity" shall mean that amount of capacity on an hourly basis scheduled by AEPCO pursuant to Federal Hydro Power Agreements.

"AEPCO Minimum Base Capacity" shall mean the capacity from Available Base Capacity that must be operated from time to time to maintain system reliability or for other reasons, reflecting AEPCO's determination as to the schedule of energy from the Federal Hydro Power Agreements and AEPCO Minimum Coal Capacity.

"AEPCO Minimum Coal Capacity" shall mean the minimum output for safe and reliable operation of Apache Units 2 and 3.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Scheduling Portal" shall mean an internet web site maintained by AEPCO and accessible by all Class A Members for the purpose of AEPCO posting ongoing information relating to the availability and minimum must run requirements for AEPCO Resources.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in its Partial Requirements Capacity and Energy Agreement. The AC for each month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of that agreement.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sale Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to the Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with this Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"CARM" or "Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources and in S&G PPA, as applicable to each All Requirements Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A to the ARM Wholesale Power Contracts.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's By-laws.

"Cost Causation" shall mean the identification of all direct and indirect costs, revenue and billing units associated with individual Resources and services, such that costs, revenue and billing units can be accounted for and billed separately to the specific Class A Members participating in such Resource or receiving such service.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AEPCO Resources.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth and designated as Existing Resources in Appendix B to Exhibit A-5 to Rate Schedule A, consisting of Base Resource(s) and Other Resource(s).

"Federal Hydro Power Agreement(s)" shall mean 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 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).

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Intra-Day Schedule" shall mean a Real-Time Schedule.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with this Schedule B.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Power Sales Resource" shall mean a sale of capacity and energy from Existing Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"Pre-Schedule Day" shall mean the day on which a Pre-Schedule must be submitted for the next Scheduling Day.

"PRM" shall mean a Partial Requirements Member.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Schedule" shall mean for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"Schedule" shall mean, for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduled Day" shall mean the Scheduling Day, as defined by WECC, for which a Pre-Schedule has been submitted.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made by AEPCO for a period of less than a year to serve load of CARM or a Member* CA as a Planning Contract Member in excess of CARM's or such Planning Contract Member's ACP shares of capacities of S&G PPA and Existing Resources.

"Tag" shall mean the collection of information in the electronic form of request and subsequent response as part of the process implemented by the North American Electric Reliability Corporation for electronically communicating a request for, securing approval of, and recording an energy transaction via the Internet.

3. AEPCO RESOURCE AVAILABILITY

3.1 Available Base Capacity.

AEPCO shall continuously notify each Scheduling Agent of Available Base Capacity by posting such information to the AEPCO Scheduling Portal. On a day-ahead and hourly basis, AEPCO will post Available Base Capacity reflecting AEPCO's determination as to the schedule of the hydropower plus available coal capacity. A Member* shall create its Base Schedules using its ACP share of Available Base Capacity as posted to the AEPCO Scheduling Portal.

3.2 Available Other Capacity.

A Member* shall create its Other Schedule of energy from its ACP share of Available Other Capacity, which may be an amount up to the difference obtained by subtracting the Member*'s ACP share of Available Base Capacity for each hour from such Member*'s AC in AEPCO Resources.

3.2.1 Once a Member* has submitted a Pre-Schedule of its Other Schedule, the Member* may not decrease such Other Schedule on an intraday basis (*i.e.* during the Scheduled Day for which the Other Schedule applies); provided, however, that in the event that a Member* experiences an unforeseen downward deviation in Native Load as compared to what was reasonably forecasted in its Pre-Schedule, such Member* shall first decrease to the extent possible its schedule from Member* Resources, and then may decrease its Other Schedule by means of an Intraday Schedule.

3.2.2 In the event that a Member* decreases an Other Schedule by means of an Intraday Schedule, the Member* shall provide to AEPCO by noon of the second subsequent Business Day evidence showing that Member*'s Native Load was, in fact, less than was reasonably forecasted in the Other Schedule. If AEPCO rejects such evidence, the Member* shall be billed

as if such Other Schedule were not decreased, and the Member* shall pay the amount billed, and may dispute its payment pursuant to the Dispute Resolution provisions of its Agreement.

3.3 Available S&G PPA Capacity.

On a day-to-day basis, AEPCO will post to the AEPCO Scheduling Portal the available capacity and the hours of each day in which AEPCO is obligated to take such capacity if scheduled, for each of the purchase power agreements which make up Available S&G PPA Capacity. A Member* shall create its S&G PPA Schedule using 100% of its ACP share of available capacity from either or both purchase power agreements of Available S&G PPA Capacity, for all the hours of the scheduling day for which AEPCO is obligated to schedule capacity from each such purchase power agreement.

3.5 Obligations of the Parties for the Period Beyond January 1, 2021.

Beginning January 1, 2021, a PRM's AC shall be reduced to reflect the effective retirement of certain Other Resources. To the extent that such retirement reduces Available Other Capacity such that a PRM's Available Other Capacity is available only as reserve capacity, the provisions of Sections 3.2. and 4.2 shall no longer be of any force or effect. In addition, a PRM's Available Base Capacity may be reduced in the event AEPCO must use Available Base Capacity to meet operating reserve requirements, unless the PRM and AEPCO agree that operating reserves may be supplied from another source.

4. MINIMUM CAPACITY REQUIREMENTS:

4.1 Minimum Base Capacity Requirements.

On a day-to-day basis, AEPCO will post to the AEPCO Scheduling Portal Minimum Base Capacity reflecting AEPCO's discretion as to the schedule of energy from the Federal Hydro Power Agreements and Minimum Coal Capacity. A Member* shall schedule and a Member* CA shall take energy available from its AC in AEPCO Resources in an hour in an amount no less than its share of AEPCO Minimum Base Capacity. A Billing Unit Entity's share of AEPCO Minimum Base Capacity shall be the product of its ACP multiplied by AEPCO Minimum Base Capacity for that hour. If a Billing Unit Entity fails to takes its Minimum Base Capacity, AEPCO shall charge a Minimum Base Capacity Charge, as applicable, either pursuant to Section 6.2.1 of this Schedule B for a PRM or pursuant to Section 2.4 of its Rate Schedule A for an ARM.

4.2 Minimum Other Capacity Requirements.

From time to time, AEPCO may be required to generate out of merit order energy from Other Resources for such reasons as: to respond to transmission constraints, to maintain reliability in certain peak periods of the year, to support generation needs in the event of an outage of a Base Resource, or to consume scheduled

natural gas deliveries in the event natural gas storage cannot be utilized. As Minimum Other Capacity is determined, AEPCO will post to the AEPCO Scheduling Portal the nature, amount, and deration of Minimum Other Capacity as in effect from hour to hour. A Member* must schedule and a Member* CA must take energy available from its Available Other Capacity in an hour in an amount no less than its share of Minimum Other Capacity. For each hour of each month, a Billing Unit Entity's share of AEPCO Minimum Other Capacity shall be the product of its ACP multiplied by AEPCO Minimum Other Capacity. If a Billing Unit Entity fails to takes its Minimum Other Capacity, AEPCO shall charge a Minimum Other Capacity Charge, as applicable, either pursuant to Section 6.2.1 of this Schedule B for a PRM or pursuant to Section 2.4 of its Rate Schedule A for an ARM.

4.3 Minimum S&G PPA Capacity.

AEPCO will dispatch, account for, and bill the costs of Available S&G PPA Capacity in accordance with one or more applicable agreements between AEPCO and all Class A Members with an ACP in S&G PPA. Schedules submitted by Members to AEPCO for the use of Available S&G PPA Capacity will comport with the actual dispatch limitations and requirements of the S&G PPA.

In each hour, a Billing Unit Entity shall be responsible for taking and paying for its ACP share, if any, of energy from S&G PPA Capacity as dispatched by AEPCO.

5. SCHEDULING:

5.1 General Scheduling Concepts.

This section establishes a framework for scheduling AEPCO Resources consistent with cost causation principles. A Member* shall submit separate Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, to AEPCO. Schedules submitted by Member*s shall not dictate physical dispatch, except in the case of the S&G PPA. AEPCO shall retain full generation control, develop forecasts of resource requirements, and dispatch the resources at its disposal using traditional economic stacking principles.

5.2 Scheduling Agent.

A Member* shall designate itself or a third party as Scheduling Agent to compute and provide to AEPCO Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, for use of energy from its AC in AEPCO Resources. The Member* shall bind its Scheduling Agent to abide by the confidentiality provisions of this Agreement in order to prohibit sharing of AEPCO Resource costs and availability information with others.

5.3 Member* Schedules.

The Scheduling Agent shall develop Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, pursuant to this Section 5 and Exhibit B-1 hereof. Scheduling Agent shall submit such Schedules to AEPCO in accordance with the timetables outlined in Exhibit B-1 hereof.

5.4 Scheduling Limitations.

Schedules may be limited in accordance with the following.

5.4.1 Scheduling Limits during Base Resource Outage or Reduction.

AEPCO will notify the Scheduling Agents as soon as practicable after the outage or reduction of a Base Resource.

For so long as AEPCO is a member of the Southwest Reserve Sharing Group or its successor (SRSG), the following time frames shall apply for scheduling in response to an outage or reduction of a Base Resource:

(a) Initial Sixty (60) Minute Period - The replacement energy for the first sixty (60) minutes following notification of the loss to the SRSG parties will be provided to AEPCO pursuant to the SRSG Agreement, and Schedules need not be adjusted for such initial sixty (60) minutes.

(b) After the Initial Sixty (60) Minute Period - The Scheduling Agent shall reduce the Member*'s Base Schedule by the Member*'s share of the lost capacity beginning at sixty (60) minutes following AEPCO's notification of the outage to the SRSG parties. In such event, the Scheduling Agent may increase its Other Schedule to replace the lost capacity; otherwise, such capacity will be replaced by AEPCO. Within ten (10) minutes of notification of a Base Resource outage or reduction, Scheduling Agent must notify AEPCO if Member* does not want to increase its Other Schedule after such sixty (60) minute period to replace the lost capacity; unless AEPCO receives such notice within such ten (10) minutes, AEPCO will replace the lost capacity. Any otherwise applicable requirements of Exhibit B-1 that set timeframes for notice will not apply in such event.

If the SRSG Agreement is terminated or AEPCO is otherwise no longer a member of SRSG, the Parties agree to diligently work to determine how the capacity will be replaced in case a Base Resource experiences an outage or reduction.

5.4.2 Scheduling Limits during Other Resource Outage.

In the event an outage or de-ration of an Other Resource occurs, AEPCO shall post notice of such event to the AEPCO Scheduling Portal and replace the reduced capacity of the Other Resource, and Scheduling Agent may but shall not be required to alter Member*'s Other Schedule. Within ten (10) minutes of notification of an Other Resource outage or reduction, Scheduling Agent must notify AEPCO if Member* plans to alter its Other Schedule; unless AEPCO receives such notice within such ten (10) minutes, AEPCO will replace the lost capacity. Any otherwise applicable requirements of Exhibit B-1 that set timeframes for notice will not apply in such event.

5.4.3 Overscheduling.

5.4.3.1 If a Scheduling Agent submits a Base Schedule in an amount that exceeds the Member*'s Available Base Capacity, the amount in excess of Member*'s Available Base Capacity will become part of the Member*'s Other Schedule for the purposes of the energy accounting of the Billing Unit Program of Exhibit A-4.

5.4.3.2 If a Scheduling Agent submits Schedules that collectively exceed the Member*'s AC for an hour, AEPCO is not obligated to provide the amount above AC, provided, however, that if AEPCO does not seek to have Member* correct such Schedules, Member* shall be subject to a penalty, calculated in accordance with Section 6.2.2.

5.5 AEPCO Scheduling Responsibilities.

5.5.1 AEPCO shall communicate by posting to the AEPCO Scheduling Portal all information required in accordance with this Section 5.5 and Exhibit B-1 hereof. Using the AEPCO Scheduling Portal, AEPCO shall publish and update Available Base Capacity, Available Other Capacity, and Available S&G PPA Capacity, all on a real time basis. In addition, AEPCO will contact and notify Scheduling Agents as soon as practicable when units become unavailable and/or are derated, and when units return to service, in whole or in part.

5.5.2 AEPCO shall be responsible for scheduling and dispatching AEPCO Resources on an economic basis to meet CARM load requirements, Member* CA load requirements, and Member* Schedules.

5.5.3 AEPCO shall make Replacement Purchases as necessary to meet load requirements and Schedules due to outages of AEPCO Resources.

5.6 Unit Limitations.

AEPCO shall maintain Resource Operation and Unit Dispatch Practices, attached hereto as Exhibit B-2 and made a part hereof, that among other things establish

limitations on the dispatching of AEPCO Resources and consequently provide a basis for AEPCO to make Other Economy Purchases and Replacement Purchases.

6. ADDITIONAL CHARGES:

6.1 Ordinary Service.

Unless otherwise provided in this Schedule B, the energy sold by AEPCO to a PRM pursuant to the Agreement shall be at the rates and charges set forth in Exhibit A-1 to Rate Schedule A to their respective Agreements.

6.2 Additional Charges.

In addition to the rates and charges set forth in Exhibit A-1 to Rate Schedule A, a PRM shall pay AEPCO the following additional amounts resulting from this Schedule B.

6.2.1 Capacity and Energy Below AC.

If a PRM is utilizing a Member* Resource, Future Resource, S&G PPA, or Supplemental Purchase in any hour to serve Native Load and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of AEPCO Minimum Base Capacity or Minimum Other Capacity, it shall pay a charge as set forth in this Section 6.2.1.

6.2.1.1 PRM Minimum Base Capacity Charge - In the event that a PRM has replaced its use of AEPCO Resources with a Member Resource, Future Resource, S&G PPA or Supplemental Purchase to serve Native Load in any hour and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of Minimum Base Capacity, AEPCO shall charge and the PRM shall pay a charge in an amount obtained by multiplying the lesser of (i) the amount of Member Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour, or (ii) the amount of the PRM's pro rata share of all PRMs' collective deficiency in their combined shares of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 to Rate Schedule A and as determined for the billing period. Member shall only be subject to PRM Minimum Base Capacity Charge to the extent that Available Base Capacity dispatched for Class A Members as a whole is below Minimum Base Capacity.

6.2.1.2 PRM Minimum Other Capacity Charge - In the event that a PRM has replaced its use of AEPCO Resources with a Member Resource, Future Resource, S&G PPA or Supplemental Purchase to serve Native Load in any hour and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of AEPCO Minimum Other Capacity, AEPCO shall charge and the

PRM shall pay an amount obtained by multiplying the lesser of (i) the amount of Member Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour, or (ii) the amount of the PRM's pro rata share of all PRMs' collective deficiency in their combined share of Minimum Other Capacity in such hour, by the Gas Energy Rate as defined in Exhibit A-4 to Rate Schedule A and as determined for the billing period.

6.2.1.3 In the event that in any hour both Sections 6.2.1.1 and 6.1.1.2 would apply, the PRM Minimum Other Capacity Charge will be determined first as set forth in Section 6.2.1.2 above, and the associated PRM Minimum Base Capacity Charge shall be an amount obtained by multiplying the lesser of (i) the amount of Member* Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour less the amount of energy used as the basis for the PRM Minimum Other Capacity Charge, or (ii) the amount of the PRM's deficiency in its share of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period.

6.2.2 Capacity and Energy Above AC.

In each month in which a Class A Member's use of AEPCO Resources exceeds its AC, AEPCO shall charge the Class A Member an amount equal to the Demand Overrun Adjustment as calculated in Section 2.3 of Rate Schedule A, and the Class A Member shall also pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Energy Rate.

7. REVISIONS TO EXHIBITS:

From time to time events will occur which will necessitate the revision of the Exhibits attached to this Schedule B. Except when such Exhibits specifically provide for updates by specific parties, such revisions shall only be made pursuant to mutual agreement of AEPCO and all PRMs.

EXHIBIT B-1

Merchant Scheduling Practices and Procedures

1. FOR MEMBERS* OUTSIDE THE AEPCO PSEUDO BALANCING AREA:

1.1 Introduction.

1.1.1 Prior to each Scheduled Day, the Scheduling Agent will provide Pre-Schedules identifying anticipated Base Schedules and Other Schedules for the Scheduling Day, as defined by WECC, by hour, to AEPCO. AEPCO may commit to natural gas purchases when Other Resources have been Pre-Scheduled.

1.1.2 On the Scheduled Day, the Scheduling Agent may submit Real-Time Schedules adjusting Base Schedules within the ramping and other operating limitations of the Base Resources located at the Apache Generating Station. Real-Time Schedules may be submitted to adjust Other Schedules in accordance with Section 3.2.1 and within the ramping and other operating limitations of the Other Resources located at the Apache Generating Station; such Real-Time Schedules adjusting Other Schedules will only be accommodated to the extent they can be coordinated with fuel scheduling adjustments. (See the operating day gas unit limitations outlined in the PRM load control transfer agreements.) All Real-Time Schedules must be submitted no later than seventy (70) minutes prior to the hour power is to flow.

1.1.3 AEPCO may be able to make exceptions and accommodate Real-Time Schedules that would require AEPCO to ramp at a faster rate than under normal operating levels when such adjustments are needed to deal with emergency situations; such requests will be dealt with case-by-case.

1.2 Pre-Schedules.

1.2.1 Scheduling Agent shall submit Member*'s preliminary estimated Pre-Schedules to AEPCO pre-schedulers by 1600 MST of the day prior to Scheduling Day as defined by WECC. The Pre-Schedules shall separately identify Base Schedules and Other Schedules. Preliminary Pre-Schedules may be submitted by phone, fax or e-mail.

1.2.2 Scheduling Agent shall submit Member*'s final Pre-Schedules to AEPCO pre-schedulers by 0630 MST of the Pre-Schedule Day. The Pre-Schedules shall separately identify Base Schedules and Other Schedules. Final Pre-Schedules may be submitted by phone, fax or e-mail.

1.2.3 Scheduling Agent is responsible for generating tags in accordance with WECC time-lines and procedures. AEPCO, as mutually agreed, may generate tags on behalf of the Scheduling Agent.

1.3 Day of Scheduling.

1.3.1 Real-Time Schedules must be provided to AEPCO at least seventy (70) minutes prior to the hour the Schedule is to flow.

1.3.2 Scheduling Agent is responsible for creating or modifying tags in accordance with WECC time-lines and procedures. AEPCO, as mutually agreed, may create tags on behalf of the Scheduling Agent.

1.3.3 In the event AEPCO chooses to modify the source of a Base Schedule or Other Schedule from its originally tagged source, AEPCO will be responsible for creating the tags associated with the modified source such Schedule. Upon notice from AEPCO no later than forty (40) minutes in advance of the hour, Scheduling Agent shall adjust any of the original tags to accommodate the new tag created by AEPCO, per AEPCO's direction.

1.4 Information Supplied by AEPCO Real Time.

1.4.1 Planned generating unit maintenance schedules.
1.4.2 Planned and unplanned full or partial generating unit outages.
1.4.3 AEPCO Minimum Base Capacity and AEPCO Minimum Other Capacity.

1.5 Emergency scheduling.

1.5.1 Schedules which do not meet the requirements in this Section 1 may be accepted by AEPCO subject to the agreement of all affected parties in the transaction.

1.6 Procedure for Rounding Tenths of MW to Whole MWs.

Initially, AEPCO will report hourly values for AC and for shares of Available Base Capacity, of AEPCO Minimum Base Capacity and of Minimum Other Capacity in tenths of a MW. To facilitate the industry standard of the scheduling of energy in whole MWs, values of hourly AC and shares of Available Base Capacity, of AEPCO Minimum Base Capacity and of Minimum Other Capacity in tenths of a MW shall be rounded down to whole MWs. Values for the hourly share of Available Other Capacity shall then be obtained by subtracting such rounded down share of Available Base Capacity from such rounded down AC for the same hour.

1.7 Intra Day Schedule Change Requiring Gas Generation.

1.7.1 As of early 2010, gas turbine minimum loading, run times and start-up cost is as follows. Applicable updates to this information shall be provided from time to time by AEPCO to Scheduling Agents.

1.7.1.1 Combine Cycle (82 MW): Minimum run time is monthly with a minimum loading of 20 MW every hour. Start-up is $4,469

1.7.1.2 Steam Unit #1 (72 MW): Minimum run time is monthly with a minimum loading of 20 MW every hour. Start-up is $4,469

1.7.1.3 Gas Turbine #1 (10 MW): Minimum run time is four (4) hours with a minimum loading of 2 MW every hour. Start-up is $1,817

1.7.1.4 Gas Turbine #2 (20 MW): Minimum run time is four (4) hours with a minimum loading of 2 MW every hour. Start-up is $1,646

1.7.1.5 Gas Turbine #3 (65 MW): Minimum run time is six (6) hours with a minimum loading of 5 MW every hour. Start-up is $1,514

1.7.1.6 Gas Turbine #4 (38 MW): Minimum run time is two (2) hours with a minimum loading of 10 MW every hour. Start-up is $ (to be provided by AEPCO)

1.7.2 El Paso Gas Scheduling Times.

1.7.2.1 Introduction.

The following closing times for each gas scheduling cycle are provided to assist Scheduling Agent when submitting Other Schedules. AEPCO requires at least a one (1) hour notice prior to such closing times in order to purchase gas from suppliers and to schedule the gas by means of El Paso's software. If there is any change to applicable closing times, AEPCO shall provide Scheduling Agents updates of such times.

1.7.2.2 Winter (Nov-Mar).
Pre-Schedule Day
Cycle 1: 0730 MST
Cycle 2: 1530 MST

Day of Flow
Cycle 3: 0930 MST
Cycle 4: 1300 MST

1.7.2.3 Summer (Apr-Oct).
Pre-Schedule Day
Cycle 1: 0630 MST
Cycle 2: 1430 MST

Day of Flow
Cycle 3: 0830 MST
Cycle 4: 1200 MST

1.8 After-the-Fact Check-Outs.

1.8.1 Mid-month - AEPCO and Scheduling Agent shall perform a mid-month check-out approximately on the 15th of each month. Check-out should include Base Schedules and Other Schedules.

1.8.2 Monthly - AEPCO and Scheduling Agent shall perform a month end check-out of schedule flow as soon as possible after the end of each month, but no later than four (4) working days after end of the month.

1.9 AEPCO Contacts.

The following contact information may be updated by AEPCO or a PRM, as applicable, at any time by providing notice to all contacts listed at the time for all other entities.

1.9.1 AEPCO Pre-Schedule Contacts

i Ron Goodman
(520) 586-5276
(520) 586-5445 Facsimile
rgoodman@aepco.coop

ii. Daniel Unrast
(520) 586-5528
(520) 586-5445 Facsimile
dunrast@aepco.coop

E-mails relating to Pre-Schedules shall be sent to all persons listed above.

1.9.2 AEPCO Real-Time Schedule Contacts

i Traders
(520) 586-5407
(520) 586-5445 fax
traders@aepco.coop

1.10 PRM Scheduling Agent Contacts.

1.10.1 PRM Scheduling Agent Pre-Schedule Contacts

i Penny Casey
(602) 605-2585
(602) 605-2831 facsimile
Casey@wapa.gov

i Tim Alme
(602) 605-2854
(602) 605-2831 facsimile

1.10.2 PRM Scheduling Agent Real-time Schedule Contacts

i On-Call Scheduler
(602) 605-2666
(602) 605-2831 fax

1.11 Contacts for After-the Fact Check-Outs.

1.11.1 AEPCO

i Ron Goodman
(520) 586-5276
(520) 586-5445 Facsimile
rgoodman@aepco.coop

ii. Daniel Unrast
(520) 586-5228
(520) 586-5445
dunrast@aepco.coop

1.11.2 PRM Scheduling Agent Contacts for After-the-Fact Check-Outs
i ??????????
(602) 605-2675
(602) 605-2490 facsimile
ii John Paulsen
(602) 605-2557
(602) 605-2831 facsimile

2. FOR MEMBER* CAS INSIDE THE AEPCO PSEUDO BALANCING AREA:

A Member* CA shall execute a Scheduling, Accounting and Reporting Services Agreement with AEPCO, which agreement shall identify any applicable scheduling practices or procedures, including procedures by which Member* CA can direct AEPCO to sell for Member* CA's benefit a specified amount of the energy to which Member* CA is entitled.

EXHIBIT B-2

AEPCO's Resource Operation & Unit Dispatch Practices

1. INTRODUCTION:

These Resource Operation & Dispatch Guidelines set forth the practices that AEPCO shall follow in: (a) operating AEPCO Resources, including the AC of the Partial Requirements Members and sales from AEPCO Resources, when: (i) Pre-Scheduling such Resources for dispatch by AEPCO on a least cost basis; (ii) placing such Resources out of service for planned or forced maintenance; (iii) making Third Party Economy Sales from such Resources and making Non-Base Economy Purchases against such Resources; (iv) purchasing for sale; (v) making power sales from such Resources; (vi) accounting for energy uses and costs; (vii) billing and collecting from third parties for capacity and/or energy sales, purchases, transmission and other services; and (viii) complying with regulatory requirements of Governmental Authorities having jurisdiction, all in accordance with the provisions of this Agreement.

2. AEPCO RESOURCE PRE-SCHEDULE PRACTICES:

AEPCO shall perform Resource pre-scheduling as follows:

2.1. Establishing Pre-schedules - AEPCO shall develop Resource Pre-Schedules in advance for each hour of the subsequent operating day(s) through midnight of the next working day in accordance with principles of least-cost dispatch of AEPCO Resources to the extent practicable. AEPCO shall submit such Pre-Schedules to TRANSCO for its implementation as required by TRANSCO. Pre-schedules shall specify sufficient Resources to serve forecast hourly AEPCO Delivered Load plus the Pre-Scheduled Energy requirements for delivery losses related to AEPCO Delivered Load. Pre-Schedules shall additionally provide AEPCO Resources on-line and operating in an unloaded state sufficient to provide Operating Reserves - Spinning Reserves and for Regulation and Frequency Response Service, both as required for AEPCO Delivered Load. Pre-Schedules shall additionally consider AEPCO provisions for unloaded and off-line generating capacity and/or interruptible load sufficient to provide for Operating Reserve - Supplemental as required for AEPCO Delivered Load. All AEPCO Resources shall be Pre-Scheduled to dispatch resources of lowest operating cost first. AEPCO shall coordinate with and provide Pre-Schedule information to all suppliers and transmitters of the AEPCO Resources involved in the Pre-Schedule. All Pre-Schedules shall be prepared with consideration for the following parameters:

2.1.1. Generator operating constraints such as minimum and maximum loading levels, ramp rates, minimum run times, maximum run times, system stability requirements (e.g., voltage support or VAR support), operating reserve requirements, planned outages, environmental compliance and any other constraint or condition affecting generation;

2.1.2. Generating unit testing requirements in accordance with Prudent Utility Practice;

2.1.3. Firm purchase contract conditions such as minimum and maximum load factors, minimum or maximum Energy take requirements, and any other constraint or condition affecting the ability to receive Capacity or Energy under the contract;

2.1.4. Generating unit outages which would limit a supplier's ability to deliver Capacity or Energy pursuant to a purchase contract;

2.1.5. The availability of Non-Base Economy Purchases from market suppliers, and the opportunity to make Third Party Economy Sales at the current market price; and

2.1.6. Transmission constraints or limitations and transmission service contract requirements which would preclude the physical delivery of Energy as contemplated by the Pre-Schedule, including loss factors.

2.2 Resource Revisions to Pre-Schedules.

Resource Pre-Schedules may be revised by AEPCO in advance of any hour to recognize changes in load requirements, generator conditions, transmission outages, market opportunities and such other needs as may occur throughout the day. AEPCO's primary purpose in making such revisions shall be to keep sufficient AEPCO Resources on-line at all times to reliably serve AEPCO Total Load. A secondary purpose shall be to reduce overall operating costs of AEPCO Resources.

3. REGULATORY REQUIREMENTS:

AEPCO shall comply with regulatory requirements of all Governmental Authorities having jurisdiction as such requirements may apply with respect to these Resource Operation and Unit Dispatch Guidelines. In the event of any conflict between such regulatory requirements and these Guidelines, such regulatory requirement shall govern.

4. AEPCO COMMITMENT GUIDELINES FOR OTHER RESOURCES:

The following unit commitment guidelines relate to the start-up and operation of Other Resources. These are intended to recognize Other Resources operation limits in order to preserve their lives and reduce the likelihood of experiencing renovation and/or extraordinary maintenance costs prior to their anticipated retirement at the end of 2020. These guidelines do not prohibit AEPCO from buying from the market in lieu of starting and operating these units at any time. The guidelines shall be as follows:

4.1 For peaking GT Units 1 and 3: These units shall be reserved for dispatch basically in super-peak hours (HE 1200 through HE 2000) in summer months of June through September (exception: GT-1 when used with Steam 1 in CC operation)

4.1.1 No nighttime commitment (off-peak hours Monday through Saturday, Sunday HE 2300 – HE 0700).

4.1.2 No winter commitment except if necessary to cover superpeak daytime periods during base load unit maintenance outages.

4.2 For peaking GT Unit 2: This unit shall not be operated and shall be held in reserve for meeting 20 MW of AEPCO's non-spinning reserve requirements, but may be started and dispatched as called upon to fulfill reserve obligations.

4.3 For peaking GT Unit 4: This unit shall be available for operation in Peak Hours and Sunday HE 0800 through HE 2200 throughout the summer period, in winter peak months (December, January), and during coal unit Existing Resource maintenance or forced outages. When operating, a portion of its Capacity as needed shall be set aside for supplementing the Spinning Reserves supplied from coal-fired Existing Resources.

4.4 For Steam 1 (in CC or not): This unit shall be available in the summer period (May through October) for daily operation around the clock as may be required to preserve load serving capability and backup to forced outage of coal-fired Existing Resources. Winter period use is permitted during coal unit maintenance outage periods and during winter peak months of December and January, but every effort should be made to utilize market purchases prior to committing the unit in winter months.

5 GUIDELINES FOR AEPCO PURCHASES AND SALES:

5.1 Maintenance Purchases.

In the event an AEPCO Resource is out of service for planned maintenance or otherwise has been taken off-line and a Replacement Purchase is needed to meet AEPCO Total Load, AEPCO may locate and contract for the replacement of such AEPCO Resource for the expected deration of the Resource outage.

5.2 Economy Sales and Economy Purchases.

5.2.1 General.

AEPCO shall at all times be cognizant of the opportunities to make and shall make appropriate Third Party Economy Sales from AEPCO Resources (with the exception of power purchased under Federal Hydro Power Agreements) and Non-Base Economy Purchases against AEPCO Resources to realize the optimum cost of Resources in the Pre-Schedule for serving AEPCO Delivered Load. Any single such Third Party Economy Sale and any single such Non-Base Economy Purchase shall not extend beyond the subsequent twelve calendar months nor exceed duration of

twelve (12) consecutive months, and otherwise shall be made in accordance with the following:

5.2.2 Economy Sales.

At any time that Capacity and Energy from an AEPCO Resource is available for sale and can be sold without jeopardizing system reliability and taking into consideration the factors governing such Resource as set forth in Section 2.1 above, AEPCO may Pre-Schedule such a sale. The price related to such Economy Sale shall exceed such Resource's marginal cost (including appropriate allowances for fixed and variable costs as determined by AEPCO from time to time) plus transmission service and ancillary services costs and losses, as applicable (Resource Cost).

5.2.3 Dump Energy Sales.

At any time that an AEPCO Resource must be maintained online for testing or for meeting subsequent hours' loads and is not otherwise needed to serve current loads, AEPCO may sell the energy surplus of such Resource as dump energy at the prevailing market price without regard to such Resource's Resource Cost.

5.2.4 Non-Base Economy Purchases.

AEPCO may Pre-Schedule a Non-Base Economy Purchase at any time an AEPCO Resource that is (i) currently being dispatched, (ii) can be taken and remain off line for the purchase period without jeopardizing system reliability, and (iii) will be replaced with a capacity or energy purchase at a price lower than its Resource Cost.

5.3 Energy Purchase for Sale.

AEPCO may from time to time enter into purchases of energy at wholesale from third party suppliers to substitute for Resources that could otherwise be dispatched (or as a temporary replacement for Resources out of service as an alternative to interrupting the sale) to support sales at wholesale from AEPCO Resources (Purchases for Sale), subject to the following:

5.3.1 The Resource Cost of such purchases plus the cost of other Resources being used to make the sale (including delivery costs and losses) shall be less than the price received from the sale;

5.3.2 Such Purchases for Sale shall not increase the operating reserve requirements or otherwise increase costs to AEPCO unless such costs are recovered in the sale price; and (iii) such purchase shall be for a deration of no greater than the deration of the sale which it supports.

EXHIBIT B

MOHAVE ELECTRIC COOPERATIVE, INC.

THIRD AMENDMENT TO PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

This Third Amendment to Partial Requirements Capacity and Energy Agreement (MEC PRC&EA) is entered into this 14 day of May, 2010, by and between Mohave Electric Cooperative, Inc., a non-profit corporation organized and existing under the laws of the State of Arizona (Member) and Arizona Electric Power Cooperative, Inc., a non-profit cooperative corporation organized and existing under the generation and transmission electric cooperative laws of the State of Arizona (AEPCO). Member and AEPCO are also hereinafter referred to individually as "Party" or collectively as "Parties."

WHEREAS, the Parties have entered into that certain Partial Requirements Capacity and Energy Agreement dated July 2, 2001, as amended January 26, 2004 and December 29, (Partial Agreement) such that Member pursuant to the Partial Agreement is an "AEPCO Partial Requirements Member," as that term is defined in the Amended and Restated Appendix A dated May 11, 2010, attached hereto and referred to herein as the "2010 Definition Appendix";

WHEREAS, the Parties intend to modify as among themselves, the manner in which rates, charges and Fixed Charges for electrical service to Member are formulated and designed in order to effect resolution of certain Rate Allocation Issues and Rate Design Issues which have developed among AEPCO and the AEPCO Class A Members, as all such capitalized terms are defined in the 2010 Definition Appendix, pursuant to the Rate Settlement Agreement dated May 14, 2010 (Rate Settlement Agreement);

WHEREAS, the Parties recognize the benefit in entering into this Amendment in order to settle the Rate Allocation Issues and Rate Design Issues, by providing for a fair, equitable and repeatable allocation of costs and revenues at issue between the PRMs and ARMs based on principles of cost causation;

WHEREAS, the Parties intend that this Amendment shall be an integral component of the Rate Settlement Agreement;

WHEREAS, AEPCO filed on October 1, 2009, an application with the Arizona Corporation Commission (ACC) in ACC Docket No. E-01773A-09-0472 to modify its rates and charges (AEPCO 2009 Rate Application);

WHEREAS, this Amendment is intended to be entered into contemporaneously with certain other substantially identical amendments to individual partial requirements capacity and energy agreements between AEPCO and the other Partial Requirements Members of AEPCO, as defined in the 2010 Definition Appendix;

WHEREAS, it is in the best interest of Member and its members to enter into this Amendment to implement the changes in AEPCO's rate formulation herein contemplated, thereby partially implementing the Rate Settlement Agreement; and

WHEREAS, the Parties wish to amend the Partial Agreement, as set forth in this Amendment;

NOW, THEREFORE, in consideration of the premises set forth above and for good and valuable consideration, the receipt and sufficiency of which the Parties hereby acknowledge, the Parties hereto, intending to be legally bound, mutually agree as follows:

Section 1. Effective Date:

This Third Amendment to the MEC PRC&EA shall become effective on the first day of the month following the latter of (1) the date of its approval by the Rural Utilities Service (RUS), (2) the date of approval by the ACC or (3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

Section 2. Amendment to Section 2.1.2:

Section 2.1.2 Delete the words "take and pay, or" from the first line.

Section 3. Amendment to Section 2.1.3:

Section 2.1.3 Shall be deleted in its entirety.

Section 4. Amendment to Section 2.6.1:

Section 2.6.1 shall be deleted in its entirety and replaced with the following:

"The Member shall have an unconditional obligation to make all payments to AEPCO required hereunder at the rates and charges and on the terms and conditions set forth herein and in Rate Schedule A. The Member shall make all payments of charges and energy charges for capacity and energy provided for under this Agreement, including without limitation, rates and charges resulting from all Required Modifications and Minor Resource, 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.

Section 5. Amendment to Section 3.4.4 (d) (ii)(c):

Section 3.4.4 (d) (ii)(c) shall be deleted in its entirety and replaced with the following:

"(c) the rates and charges 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."

Section 6. Amendment to Section 5.1:

The last two (2) sentences of Section 5.1 shall be deleted in their entirety and replaced with the following:

"Member shall make all payments to AEPCO that are required pursuant to this Agreement at the rates, charges, 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 5.6 hereof. All such rates, charges 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."

Section 7. Amendment to Section 5.3:

Section 5.3 shall be deleted in its entirety and replaced with the following:

"O&M Charge. AEPCO shall charge, and the Member shall pay all operations and maintenance costs and expenses based on its ACP 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."

Section 8. Amendment to Section 5.4:

Section 5.4 shall be deleted in its entirety and replaced with the following:

"Energy Charges. Subject to Schedule B 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 monthly energy charges as determined, and set forth in, and due and payable, pursuant to Rate Schedule A."

Section 9. Amendment to Section 5.6:

Section 5.6 shall be deleted in its entirety and replaced with the following:

"Rate and 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 charges for electric energy and capacity provided hereunder, under any Partial Requirements Capacity and Energy Agreement with any other Class A Member, and under the Existing

Wholesale Power Contracts with AEPCO's All Requirements Members. If such rates or charges 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 charges with the effective date thereof, and the basis upon which the rates or charges are proposed to be adjusted and set. The Member agrees that the rates and charges 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 charges pursuant to such revised rates and charges; provided that no such revised rates or charges shall be effective if they have been disapproved in writing by the Administrator. AEPCO shall design and set future rates and charges 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."

Section 10. Amendment to Section 5.7:

Section 5.7 shall be deleted in its entirety and replaced with the following:

"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 charges charged to the Member in accordance with Rate Schedule A."

Section 11. Amendment to Section 5.9:

Section 5.9 shall be deleted in its entirety and replaced with the following:

"Reasonable Rate. The Parties agree that the rates, charges, rate methodology, and 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 charges 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 charges 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."

Section 12. Amendment to Section 5.11:

Section 5.11 shall be deleted in its entirety and replaced with the following:

"Cost Responsibility. The rates and charges 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 among the AEPCO 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."

Section 13. Amendment to Section 5.12:

Section 5.12 shall be deleted in its entirety and replaced with the following:

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

Section 14. Amendment to Section 6.2.5:

Section 6.2.5 shall be deleted in its entirety and replaced with the following:

"The Parties agree that the rates and charge methodology and principles of cost allocation set forth in this Agreement are just and reasonable."

Section 15. Amendment to Section 16.1 (b):

Section 16.1(b) shall be deleted in its entirety and replaced with the following:

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

Section 16. Amendment to Section 10 Committees:

Section 10 is hereby amended in its entirety and replaced with the Section 10 attached hereto as Attachment 1.

Section 17. 2010 Definition Appendix:

Appendix A is hereby amended in its entirety and replaced by the Amended and Restated Appendix A dated May 11, 2010, attached hereto.

Section 18. Amendment to Rate Schedule A and all revisions thereto, attached to the Partial Agreement:

Rate Schedule A attached to the Partial Agreement and all revisions thereto shall be amended in its entirety and replaced with the Rate Schedule A dated May 11, 2010, attached hereto as Attachment 2.

Section 19. Amendment to Schedule B and all revisions thereto, attached to the Partial Agreement:

Schedule B attached to the Partial Agreement and all revisions thereto shall be amended in its entirety and replaced with the [redacted] Schedule B dated May 11, 2010, attached hereto as Attachment 3.

Section 20. Miscellaneous:

(a) Extent of Amendment. Except as expressly herein set forth, all of the terms and conditions of the Partial Agreement are herein ratified and confirmed and shall remain in full force and effect.

(b) Counterparts. This Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Amendment by signing any such counterpart.

(c) Binding Effect. This Amendment shall be binding upon the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the undersigned have duly executed this Third Amendment to Partial Agreement, effective as of the date set forth below.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

By:____________________
Name: Gary G. Grim
Title: Senior Vice President and Chief Operating Officer
Date: 5/11/10

MOHAVE ELECTRIC COOPERATIVE, INC.

By:____________________
Name:____________________
Title:____________________
Date:____________________

Section 18. Amendment to Rate Schedule A and all revisions thereto, attached to the Partial Agreement:

Rate Schedule A attached to the Partial Agreement and all revisions thereto shall be amended in its entirety and replaced with the Rate Schedule A dated May 11 2010, attached hereto as Attachment 2.

Section 19. Amendment to Schedule B and all revisions thereto, attached to the Partial Agreement:

Schedule B attached to the Partial Agreement and all revisions thereto shall be amended in its entirety and replaced with the [redacted] Schedule B dated May 11 2010, attached hereto as Attachment 3.

Section 20. Miscellaneous:

(a) Extent of Amendment. Except as expressly herein set forth, all of the terms and conditions of the Partial Agreement are herein ratified and confirmed and shall remain in full force and effect.

(b) Counterparts. This Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Amendment by signing any such counterpart.

(c) Binding Effect. This Amendment shall be binding upon the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the undersigned have duly executed this Third Amendment to Partial Agreement, effective as of the date set forth below.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

By:______________________________
Name:____________________________
Title:_____________________________
Date:_____________________________

MOHAVE ELECTRIC COOPERATIVE, INC.

By:______________________________
Name: LYN R. OPALKA
Title: PRESIDENT
Date: 5/14/10

ATTACHMENT 1 to Third Amendment to Partial Agreement

Section 10. Operations Review Committee:

10.1 The Class A Members of Generating Cooperative (Class A Members), including Member, shall have an opportunity to make recommendations to the Operations and Construction Committee (OCC) and the Finance and Audit Committee (FAC) of the Board of Directors of Generating Cooperative (AEPCO) and to the AEPCO Board as described below on any matters that relate to the service and cost of the service provided by AEPCO to Member through the representative of each on a committee (Representative) herein designated as the Operations Review Committee (Committee).

10.2 The Committee shall consist of one authorized Representative from each Class A Member and a Representative designated by AEPCO, who shall serve as Chairperson of the Committee. Each Class A Member shall designate as its Representative an employee of such Class A Member with experience in the areas in which the Committee will function and AEPCO shall designate the Chairperson, who shall be an AEPCO employee.

10.3 Each Class A Member shall evidence the appointment of its Representative by written notice to the other Class A Members and AEPCO, and by similar notice, any Class A Member or AEPCO may change its Representative on the Committee at any time. The list of Committee Representatives will be updated by the Chairperson and distributed to each of the Class A Members with appropriate contact information as necessary to keep the list current as to representation on the Committee.

10.4 Each Class A Member shall be entitled to one vote through its Representative on matters that come before the Committee. In the absence of unanimous consent, the various positions of the Representatives shall be compiled, referred and communicated to the OCC and or FAC by those Representatives electing to do so.

10.5 The Committee shall meet in person or telephonically quarterly except as otherwise determined by the Committee, but in no event less frequently than annually. The Representatives shall determine the agenda of the Committee and have access to all information related to the resources used by AEPCO to provide service.

10.6 Prior to the beginning of each calendar year, and as may be required during any such calendar year, an agenda for the Committee meeting will be solicited from the Representatives and the Committee will receive, consider and review all information requested by the Committee including but not limited to the Apache Station Operations and Maintenance Budget, Capital Budget and Construction Work Plans, A & G expenses proposed by AEPCO management, load forecasts, financial forecasts, cash flow forecasts, rate filings and forecasts, and review variances, updates and amendments thereto and such other operations data as may be requested. Following consideration thereof by the Committee, the Chairperson will promptly report to either the OCC or the FAC, as appropriate, such recommendations concerning any issues considered together with alternatives raised by a Representative. The Representatives may make reports through the AEPCO Director for the Member they represent on the positions they sponsor if they differ from the Committee recommendation report to the OCC or the FAC. Such reports to the OCC and the FAC given by the Chairman and the sponsoring Director(s) shall present all alternatives considered by the Committee in addition to the recommendations of the Committee. Representatives of the Committee may assist in the presentation by their Director(s) of alternatives considered by the Committee for the Board's review in making the final Board decision.

Appendix A
Amended and Restated Definitions

APPENDIX A

AMENDED AND RESTATED: DEFINITIONS
DATED May 11, 2010

1. These Definitions shall have the respective meanings set forth herein for use in the following agreements and their exhibits and schedules (unless the context in which the term is used in a particular agreement clearly requires otherwise):

   1. MEC Partial Requirements Capacity and Energy Agreement;
   2. SSVEC Partial Requirements Capacity and Energy Agreement;
   3. TRICO Partial Requirements Capacity and Energy Agreement;
   4. Resource Integration Agreement;
   5. SSVEC Transmission Agreement;
   6. MEC Transmission Agreement;
   7. TRICO Transmission Agreement;
   8. Network Service Agreement;
   9. Member Agreement between AEPCO, SWTC, Sierra and ANZA, DVEC, GCEC, MEC, SSVEC and TRICO.

2. These Definitions shall not be amended or modified without advance notice, review and approval by all parties to any of the agreements listed above, and RUS (as hereinafter defined), which remain executory, and after providing to all parties in advance a listing of any such agreements in which a proposed amended or modified defined term is contained.

3. The following shall be used in interpreting these Definitions and the agreements listed above:

   3.1 Unless otherwise required by the context in which any term appears:

   (a) Capitalized terms used in any agreement listed above shall have the meanings specified in this Appendix A or, if used solely within an Agreement, as set forth in such agreement.

   (b) The singular shall include the plural and the masculine shall include the feminine and neuter.

   (c) References to "Articles," "Sections," "Schedules," "Appendices" or "Exhibits" shall be to articles, sections, schedules, appendices, or exhibits of the agreement(s) specified, and references to paragraphs shall be to separate paragraphs of the section or subsection in which the reference occurs.

   (d) The words "herein," "hereof", "hereinbelow" and "hereunder" shall refer to an agreement, specified as a whole and not to any particular section or subsection of such agreement; the words "include," "includes" or "including" shall mean "including, but not limited to"; and the words "best effort(s)" shall mean a level of effort which, in the exercise of reasonable judgment in the light of facts known at the time a decision is made, can

be expected to accomplish the desired result at a reasonable cost, consistent with Prudent Utility Practice (as hereinafter defined).

(e) Except where the context otherwise indicates, the term "day" shall mean a calendar day, and whenever an event is to be performed by a particular date, or a period ends on a particular date, and the date in question falls on a weekend, a legal holiday in the State of Arizona, or a day when the relevant cooperative is not open for business, the event shall be performed, or the period shall end, on the next succeeding business day.

(f) All accounting terms not specifically defined herein or by specified Accounting Requirements (as hereinafter defined) shall be construed in accordance with Generally Accepted Accounting Principles in the United States of America, consistently applied.

3.2 All references herein to the term "cooperative" shall be to AEPCO, TRANSCO, CSP or a Member (as hereinafter defined) cooperative as appropriate from the context in an agreement.

3.3 All references to a particular entity shall include such entity's successor and permitted assigns.

3.4 All references herein to any agreement, including its schedules, exhibits and appendices, shall be to such agreement as amended, supplemented or modified.

3.5 All references herein to any Law (as hereinafter defined) shall be to such Law as amended, supplemented, modified or replaced.

3.6 The titles of the articles and sections of the agreements have been inserted as a matter of convenience of reference only and shall not control or affect the meaning or construction of any of the terms or provisions thereof.

3.7 The parties have agreed to the wording of the agreements, and none of the provisions thereof shall be construed against one party on the ground that any party is the author of such agreement or any part thereof.

3.8 In any defined term which begins with the word "PRM*," the word PRM* may be replaced with the name of a Partial Requirements Member. When the name of a Partial Requirements Member is substituted, the definition remains the same but is applicable only to the named Partial Requirements Member. For example, "'PRM* Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load." If MEC is substituted, "'MEC Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of MEC to MEC AEPCO Load."

"AC" shall mean Allocated Capacity.

"ACC" shall mean Arizona Corporation Commission or any State of Arizona regulatory agency succeeding to its powers and functions.

"Accounting Report" shall mean the report prepared by TRANSCO that accounts for all of the installed cost of each transmission facility constructed or acquired by TRANSCO as a part of the TTS and classifies such facility or portion thereof and apportions its installed cost as an All Requirements Resource Facility, an Existing System Facility, a Load Growth System Facility, a Power Sale Resource System Facility, a Resource Facility, or a Reliability System Facility, for the purposes of Sections 2 and 6 hereof and consistent with Accounting Requirements.

"Accounting Requirements" shall mean the requirements of any system of accounts prescribed by the RUS as long as RUS is the holder of any obligation of a cooperative; provided, however, that if a cooperative is specifically required by another Governmental Authority to employ the system of accounts prescribed by that Governmental Authority, then "Accounting Requirements" means the system of accounts prescribed by that Governmental Authority; provided, further, however, that if RUS is not a holder of any obligation or, if a holder, RUS does not prescribe a system of accounts applicable to the cooperative, and the cooperative is not specifically required by another Governmental Authority to employ that entity's system of accounts, then "Accounting Requirements" means the requirements of Generally Accepted Accounting Principles or another comprehensive basis of accounting applicable to like entities conducting business similar to that of the cooperative. Generally Accepted Accounting Principles refers to a common set of accounting standards and procedures that are either promulgated by an authoritative accounting rulemaking body or accepted as appropriate due to widespread application in the United States.

"Additional AEPCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by AEPCO.

"Additional CSP Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by CSP.

"Additional TRANSCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by TRANSCO.

"Administrator" shall mean the Administrator of RUS or any other federal regulatory agency or department succeeding to the Administrator's power or functions as a lender or mortgagee to a cooperative.

"AEPCO" shall mean Arizona Electric Power Cooperative, Inc., a non-profit generation and transmission cooperative corporation organized under the Laws of the State of Arizona.

"AEPCO Available Resource(s)" shall mean that portion of AEPCO Resources representing operating reserves which can be sold on an interruptible basis and surplus to AEPCO Total Load.

"AEPCO By-law Amendments" shall mean the amendments to the AEPCO By-laws relating to governance, in the form adopted by AEPCO in accordance with the terms of the AEPCO By-laws and the Laws of the State of Arizona.

"AEPCO By-laws" shall mean the By-laws adopted and amended by the Members or Board of Directors of AEPCO in accordance with the Laws of the State of Arizona.

"AEPCO Class A Member" shall mean (i) any Class A Member which purchases power and energy from AEPCO pursuant to any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement and is listed in Recital B to the Partial Requirements Capacity and Energy Agreement; or (ii) is determined to be a Class A member by the terms of the AEPCO By-laws.

"AEPCO Closing Date Allocation and Attribution" shall mean the allocations and attributions to be made by AEPCO on the Closing Date, as set forth in Section 2.6 of the Member Agreement and Section 2.3 of the Restructuring Agreement.

"AEPCO Delivered Load" shall mean the aggregate of the demand requirements and the associated energy requirements of all electric loads served from AEPCO Resources (including distribution losses but not including reserves or transmission losses), and shall consist of:

1. The loads of All Requirements Members served from AEPCO Resources;
2. PRM*AEPCO Load;
3. PRM*AEPCO Sales;
4. Power Sales Loads; and
5. CSP AEPCO Load.

"AEPCO Employees" shall mean those individuals employed by AEPCO as of the Closing Date.

"AEPCO Federal Hydro Power Capacity" shall mean that amount of capacity on an hourly basis scheduled by AEPCO pursuant to Federal Hydro Power Agreements.

"AEPCO Load Forecast" shall mean a listing of the demand and associated energy requirements of AEPCO Total Load (by month for the Resource Forecast Period) to be served from AEPCO Resources

"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 the Partial Requirements Capacity and Energy Agreements and the Existing Wholesale Power Contracts.

"AEPCO Minimum Base Capacity" shall mean the capacity from Available Base Capacity that must be operated from time to time to maintain system reliability or for other reasons, reflecting AEPCO's determination as to the schedule of energy from the Federal Hydro Power Agreements and AEPCO Minimum Coal Capacity.

"AEPCO Minimum Coal Capacity" shall mean the minimum output for safe and reliable operation of Apache Units 2 and 3.

"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.

"AEPCO Notes" shall mean written instruments or notes which evidence the obligation of AEPCO for loans that in whole or in part financed the construction of AEPCO's generation and transmission facilities, the payment of which is guaranteed by the Government pursuant to the REAct, and those written instruments or notes of AEPCO outstanding on the Effective Date (with respect to the MEC Partial Requirements Capacity and Energy Agreement), the Agreement Date (with respect to the SSVEC Partial Requirements Capacity and Energy Agreement), or the Approval Date (with respect to the TRICO Partial Requirements Capacity and Energy Agreement) payable to the Government evidencing loans made by the Government, acting by and through the Administrator of RUS, pursuant to the REAct, or evidencing reimbursement obligations of AEPCO to the Government with respect to the Government's guarantee of the payment of certain notes payable to the order of FFB and all amendments, supplements, extensions, and replacements to, of, or for, such notes, and loans made by, or securities issued to, or obligations undertaken to, others, including the Financial Entities. AEPCO Notes in the future will also include written instruments, which may evidence additional or new loans or advances that AEPCO may obtain to finance the construction or purchase of new facilities, Future Resources or the modification of Existing Resources, as applicable.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Retained Personnel" shall mean AEPCO management and other personnel designated as such by the chief executive officer of AEPCO.

"AEPCO's Revenue Requirement" shall mean the total revenues, from any source whatsoever, necessary to enable AEPCO, utilizing a twelve (12) 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) include 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, determined in accordance with Accounting Requirements.

“AEPCO's Revenue Requirement from AEPCO's Class A Members” shall mean that portion of AEPCO's Revenue Requirement less revenues anticipated by AEPCO from all other sources than the AEPCO Class A Members.

“AEPCO’s Revenue Requirement From Partial Requirements Members” shall mean that portion of AEPCO’s Revenue Requirement from AEPCO Class A Members allocated to Partial Requirements Members in accordance with Section 5 of the Partial Requirements Capacity and Energy Agreements and Section 3 of Rate Schedules A.

“AEPCO Scheduling Portal” shall mean an Internet web site maintained by AEPCO and accessible by all Class A Members for the purpose of AEPCO posting ongoing information relating to the availability and minimum must run requirements for AEPCO Resources.

“AEPCO Secured Obligations” shall mean the AEPCO Notes, loans made by, or securities issued to, or debt obligations entitled to the lien created by the AEPCO Mortgage.

“AEPCO Total Load” shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

“Agreement Date” shall mean the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC.

“All Requirements Member” shall mean any Class A Member of AEPCO that is currently a party to any Wholesale Power Contract with AEPCO which provides for the purchase from AEPCO of all such Member’s requirements of electric power, which as of the Effective Date consisted of ANZA, DVEC, GCEC, SSVEC AND TRICO, which as of the Agreement Date consisted of ANZA, DVEC, GCEC and TRICO, and which as of the Approval Date shall consist of ANZA, DVEC and GCEC.

“All Requirements Resource Facility” shall mean any System Facility, or portion hereof, or Direct Assignment Facility that is required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future resource in which MEC and SSVEC have no ACP.

“Allocated Capacity” or “AC” shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in its Partial Requirements Capacity and Energy Agreement. The AC for each

month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of such agreement.

"Allocated Capacity Percentage" or "ACP" of a Class A Member shall mean the percentage allocation with respect to an AEPCO Resource, for which, if it is a Partial Requirements Member, such Member is responsible, including the allocation of electric capacity, cost responsibility and revenues, as set forth in its Partial Requirements Capacity and Energy Agreement. Appendix A to Exhibit A-5 to Rate Schedule A sets forth the ACP for each Class A Member with respect to Existing Resources and the S&G PPA.

"Ancillary Services" shall mean the ancillary services required by FERC to be made available with transmission service in accordance with the FERC pro-forma open access transmission tariff, including; but not limited to scheduling, system control and dispatch service; reactive supply and voltage control from generation sources service; regulation and frequency response service; energy imbalance service; operations reserve-spinning reserve service, and; operating reserve - supplemental reserve service, all as such terms are further defined by FERC in Order No. 888 and 889 and identified in transmission tariffs and service agreements of TRANSCO.

"Annual Planning Report" shall mean the annual written report and analysis given to AEPCO of a Class A Member's short, intermediate and long-range forecast of load and such other planning data required by the Resource Integration Agreement.

"Annual Transmission Requirements Report" shall have the meaning set forth in Section 5 of Schedule B hereto (Transmission Planning Policies).

"ANZA" shall mean Anza Electric Cooperative, Inc., a non-profit electric cooperative corporation organized and existing under the Laws of the State of California.

"Applicable Additional Contract" shall mean each additional contract as set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement, which either the Restructuring Agreement or the Member Agreement requires to be executed by each party to the Agreements.

"Approval Date" shall mean the first day of the month, no earlier than December 1, 2010, following the latter of 1) the date upon which the TRICO Transmission Agreement and the TRICO PRC&EA shall have been approved by the RUS, 2) the date upon which the TRICO PRC&EA shall have been approved by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

"ARM Energy Cost Responsibility Share or ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Assignment for Security" shall mean an assignment, transfer, mortgage or pledge of a party's interest in an Agreement made as security for any obligation secured by any

indenture, mortgage, deed, deed of trust, security instrument, or similar lien on its system assets, without limitation on the right of the secured party to further assign such Agreement.

"Authorized Representative" shall mean a representative designated by a party pursuant to the terms of an Agreement and authorized to act for such party in certain matters as set forth in the relevant terms of such Agreement.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available Resource(s)" shall mean the Pooled Resource(s) surplus to Pooled Load available for sale or dispatch as Merchant Sales.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Available Transmission Resources" shall mean the transmission facilities and contract rights of the Parties (as set forth in Schedule E attached) required for the delivery of Pooled Resources to Pooled Loads.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer Energy of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"Bonds" shall mean the CFC Guaranteed Solid Waste Disposal Revenue Bonds (Series 1994Adw) and the CFC Guaranteed Pollution Control Revenue Refunding Bonds (Series 1997C).

"CARM or Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources applicable to each All Requirements Member of AEPCO as set forth in Appendix A to Exhibit A-5 to the Rate Schedule A of the ARM Wholesale Power Contracts.

"CFC" shall mean the National Rural Utilities Cooperative Finance Corporation, a corporation organized under the Laws of the District of Columbia, or similar successor agency.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's By-laws.

"Closing" shall mean the execution and delivery of any and all documents and the tendering, transferring or delivering of all payments required to be made or otherwise necessary or desirable to consummate the transactions contemplated by the Restructuring Agreement and the Member Agreement, including such actions and documents described in the Closing Memorandum as specified in Section 8.1 of both the Restructuring Agreement and the Member Agreement, following satisfaction or waiver, if any, of the conditions for Closing therein.

"Closing Date" shall mean the date on which the Closing occurs.

"Closing Memorandum" shall mean the memorandum agreed to by the parties to the Member Agreement prior to the Pre-Closing which sets forth the consents, assignments, transfers, delivery of other approvals, documents, legal opinions, payments and transaction documents to be furnished by the parties, other conditions for Closing, and events and actions required to effect the Closing

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Collected Funds" shall mean deposited funds in a banking institution that are immediately available for use without any float restrictions.

"Contract Rate of Interest" shall mean the lesser of: (i) the interest rate equal to the effective "Prime Rate" per annum as specified in the "Money Rates" section of the Wall Street Journal or, (ii) the maximum interest rate permitted by applicable Law in the State of Arizona if any is so stated.

"Cost Causation" shall mean the identification of all direct and indirect costs, revenue and billing units associated with individual Resources and services, such that costs, revenue and billing units can be accounted for and billed separately to the specific Class A Members participating in such Resource or receiving such service.

"CSP" shall mean Sierra Southwest Cooperative Services, Inc., a non-profit corporation organized under the generation and transmission cooperative corporation Laws of the State of Arizona.

"CSP Actual AEPCO Load Data" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP AEPCO Load" shall mean the sum of the demand and associated energy requirements, including distribution losses, but not including reserves or transmission losses, of the Member JMP Load of each Class A Member and of those other loads for which CSP purchases capacity and energy from AEPCO as specified in separate sales agreements between AEPCO and CSP.

"CSP AEPCO Load Forecast" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP Assets" shall mean all capital stock of TSEPP, personal property, authorization to make Retail Sales, intangible assets, employee benefit plans, intellectual property, software licenses, employee or consultant agreements, equipment leases and contracts, licenses, any chose in action, and other agreements related to the performance of the CSP Business identified on Schedule 2 to the Restructuring Agreement.

"CSP Business" shall mean (i) the business of power sales and retail sales; (ii) the provision of personnel and consulting services to AEPCO, TRANSCO, and others pursuant to contract; and, (iii) the ownership and use of the CSP Assets, including responsibility for CSP Liabilities.

"CSP JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of those loads within a Member's Distribution Service Area served using capacity and energy provided by CSP from CSP Resources pursuant to a Joint Marketing Agreement between a Class A Member and CSP.

"CSP Liabilities" shall mean (i) the CSP liabilities identified on Schedule 2 to the Restructuring Agreement, as such obligations exist as of the Closing Date; and (ii) such other obligations relating to the performance of the CSP Business as CSP, AEPCO and TRANSCO may agree upon from time to time in other agreements; and (iii) any liabilities which CSP assumes in accordance with its By-laws.

"CSP Member" shall mean AEPCO, TRANSCO and the Class A Members of AEPCO on the Closing Date and any Person, which has become and retains membership in CSP in accordance with the CSP By-laws.

"CSP Resource" shall mean a Resource owned or purchased by CSP from third parties.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Debt Service Coverage Ratio" or "DSC" shall mean the financial ratio determined, based on figures shown on RUS Form 12 for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) depreciation and amortization expense, (b) interest on long-term debt (increased by one-third of the amount, if any, by which long-term leases exceed two percent of total margins and equities less regulatory assets), and (c) net patronage capital or margins and (2) dividing the sum obtained by the total of interest and principal billed under long-term debt and debt service requirements.

"Deficiency Purchase" shall mean the purchase of additional capacity and energy through the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1.1 herein, which purchase is required to supply capacity and associated energy to meet AEPCO Total Load, if it is the Purchasing Party, or MEC Total Load if MEC is the Purchasing Party.

"Delivery Point" shall mean the interconnection between the TTS and the transmission, distribution system or load of a Class A Member at which TRANSCO is to deliver capacity or energy pursuant to the Transmission Agreement or the Network Service Agreement.

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

"Direct Assignment Facilities" shall mean those transmission lines, substation facilities (or components thereof) and firm wheeling purchased by TRANSCO, for the sole use and benefit of a TRANSCO Member or of a particular transmission customer receiving service under the TRANSCO Tariff.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.

"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"DVEC" shall mean Duncan Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Economy Purchase(s)" shall mean a wholesale purchase of capacity and/or energy for a term not to exceed one year (including all renewal periods) entered into by AEPCO.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sale(s)" shall mean a wholesale sale by AEPCO of capacity and energy from AEPCO Available Resources made for monthly, daily or hourly periods of the next twelve months on a pre-scheduled basis.

"Economy Sales Price" shall mean for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Effective Date" shall mean either (i)________________, or (ii) the Closing Date.

"Eligible Customer For TRANSCO " shall mean any of the following: (i) any electric utility (including AEPCO, CSP or any power marketer), Federal Power Marketing Agency, or any Person generating electric energy for sale for resale (electric energy sold or produced by any such entity may be produced in the United States, Canada or Mexico) or (ii) any Person offering retail electric service to others or taking retail service pursuant to a state requirement that TRANSCO offer unbundled transmission service or to a voluntary offer of such service by TRANSCO.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Engineering Analysis Requirement" shall mean have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.

"Equity" shall be defined in accordance with Accounting Requirements.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G and Supplemental Billing Energy.

"Exercise Date" shall mean date certain on or before which The Possible Selling Party or Parties shall provide notice to the Purchasing Party or Parties of an election pursuant to Section 10.1.1 herein to exercise The First Right of Refusal among AEPCO and MEC.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth and designated as Existing Resources in Appendix B to Exhibit A-5 to Rate Schedule A, consisting of Base Resource(s) and Other Resource(s).

"Existing System Facility" shall mean any System Facility that is in service or has been acquired as of the Agreement Date, and improvements thereto and replacements thereof occurring during the term of the Agreement.

"Existing Wholesale Power Contract" shall mean the Wholesale Power Contract between AEPCO and a Class A Member, and when used in the plural shall mean such contract and similar contracts between AEPCO and each of the Class A Members pursuant to which, in either case, such Class A Member purchases or purchased all its requirements of electric power from AEPCO prior to its becoming a Partial Requirements Member.

"FERC" shall mean the Federal Energy Regulatory Commission, an agency of the United States Department of Energy, or regulatory agency succeeding to the powers and functions thereof.

"Federal Hydro Power Agreement(s) shall mean 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 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).

"FFB" shall mean the Federal Financing Bank, an instrumentality and wholly owned corporation of the Government or any agency or department of the Government succeeding to the powers and functions thereof.

"Final Load Ratio Share of PRM*" shall mean the Load Ratio Share of PRM* in effect as of the Last Service Date.

"Financial Entities" shall mean collectively RUS, CFC, FFB, the trustees and bondholders of the Bonds and other lending institutions or issuers of debt who have made loans to or hold securities or other obligations of a cooperative.

"First Right(s) of Refusal" shall mean reciprocal one-time rights of first refusal to sell capacity and associated energy granted by the purchasing party to the selling party pursuant to Section 10.1 of the Resource Integration Agreement. Certain conditional first rights of refusal provided by CSP to AEPCO as set forth in Section 14 of the Resource Integration Agreement shall not be deemed to form a part of this defined term.

"First Right(s) of Refusal Period" shall mean the time period during which the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1 of the Resource Integration Agreement shall be in effect commencing on the Effective Date and ending on September 1, 2001.

"Fixed Charge" shall mean the charge computed in accordance with Section 5.2 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Force Majeure" shall mean the occurrence or non-occurrence of any act, event or cause beyond the control of a party to an Agreement whereby the party is unable to perform its obligation, other than the obligation to pay money, which act, event or cause by that party's exercise of due diligence could not have reasonably been expected and avoided, or which even with the exercise of due diligence, the party has not been able to overcome or avoid or cause to be avoided. Such act, event or cause shall include, but not be limited to: acts of God; failure or threat of immediate failure of facilities; explosions, flood, drought, earthquake, storm, fire, pestilence, lightning and other natural catastrophes; epidemic; war; riot; civil disturbance or disobedience, strike, or labor disturbance, disputes or unrest of whatever nature; civil disputes or unrest of whatever nature; labor, material or fuel shortage; sabotage; vandalism; restraint by court order or public authority; a failure or threat of failure of any generating or transmission facility, which is likely to cause an outage of electric service to customers served from that party's system (including transmission curtailments by a transmission provider) or to cause such party to experience a rapid decline in system voltage or frequency; and, action or non action by or inability to obtain the necessary authorizations or approvals from any Governmental Authority (but not including the ACC or RUS), provided however, that no act, event or cause that is the result of the lack of necessary financial resources shall constitute an event of "Force Majeure," nor shall an act, event or cause that is the result of the negligence of the party claiming Force Majeure constitute an event of "Force Majeure."

"Form 12A Balance Sheet" shall mean RUS Form 12a, Section B, Balance Sheet.

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Resource" shall mean (i) any new AEPCO Generating Resource, or (ii) any AEPCO Power Purchase Resource with a term of greater than one (1) year; either of which Resource would require the assignment of a new ACP to each Class A Member participating in such Resource and an amendment, or a new Exhibit to Rate Schedule A.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"GCEC" shall mean Graham County Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona

"Generally Accepted Auditing Standards" shall mean a common set of auditing standards and procedures that have been developed over time by several auditing boards, the most current set of standards and procedures of which is the Auditing Standards Board.

"Generating Resource" shall mean an interest in any existing, additional, modified or repowered generating facility or unit, which may be owned (jointly or individually), leased or otherwise acquired by AEPCO, provided that in connection with any lease of an Existing Resource, such leasehold interest shall not be deemed to be a Future Resource for purposes of the Partial Requirements Capacity and Energy Agreement.

"Generation Business" shall mean with respect to AEPCO: (i) the business of generation of electricity; (ii) operation of the Resource Pool; and, (iii) the use, ownership, rights, obligations and duties associated with the generation assets including its agreements for Power Purchase Resources, Power Sales Resources, Economy Purchases and Economy

Sales including, but not limited to, the Existing Wholesale Power Contracts and the Partial Requirements Capacity and Energy Agreement.

"Government" shall mean the federal government of the United States of America.

"Governmental Authority" shall mean any local, state, regional, federal, or national administrative, legal, judicial, or executive governmental agency, commission, department, or other governmental entity having jurisdiction over AEPCO, TRANSCO, CSP, their respective Members, or any of their activities.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Indebtedness" shall mean:

(1) debt incurred or assumed by a cooperative for borrowed money, or debt incurred for the reimbursement of money advanced under any credit support agreements if in either case categorized as debt according to Accounting Requirements;

(2) lease obligations, if categorized as debt according to Accounting Requirements;

(3) debt incurred or obligations assumed for facilities or power purchases included in a Member's ACP;

(4) debt incurred or obligations issued to finance the amount of a pre-payment; or

(5) debt for any Person (other than debt otherwise treated as Indebtedness hereunder) described in clauses (1), (2), (3) or (4) above which are guaranteed (whether by payment or collection) by the cooperative, provided that none of the following shall constitute Indebtedness:

   (A) guarantees of performance or payment by, or any obligations of, any Person under contracts to pay for fuel for the system; and

   (B) guarantees of performance by any Person for other than payment of debt incurred or assumed for borrowed money, or any obligation if categorized as debt according to Accounting Requirements, including, without limitation, all debt (other than indebtedness otherwise treated as Indebtedness hereunder) for borrowed money or the acquisition, construction or improvement of property or capitalized lease obligations guaranteed directly or indirectly, in any manner by a cooperative, or in effect guaranteed, directly or indirectly, by such cooperative through an agreement, contingent or otherwise, to assume any such indebtedness or to advance or supply funds for the payment or purchase of any such indebtedness or to purchase property or services primarily for the purpose of enabling the debtor or seller to make payment of such indebtedness, or to assure the owner of the indebtedness against loss, because of such indebtedness or to supply funds to or in any other manner invest in the debtor (including any agreement to

pay for property or services irrespective of whether or not such property is delivered or such services are rendered) or otherwise.

"Interest Expense" shall mean an amount constituting interest on long-term Indebtedness (less any interest during construction and allowance for funds used during construction including an interest rate swap collar, floor forward or other hedging agreement, arrangement or security, however denominated) and other interest expense computed in accordance with Accounting Requirements.

"Intra-Day Schedule" shall mean a Real-Time Schedule.

"Joint Marketing Agreement" shall mean an agreement by and between CSP and a Class A Member pertaining to joint competitive retail electric marketing and sales activities, in accordance with applicable Law, within such Member's Distribution Service Area.

"Joint Marketing Plan" shall mean a plan designed by and entered into between CSP and a Class A Member concerning Retail Sales, the form of which is set forth in Exhibit B to the Joint Marketing Agreement.

"Last Service Date" shall mean the last date on which TRANSCO provides service to PRM* pursuant to Section 2 of a PRM* Transmission Agreement, unless otherwise extended by mutual agreement of the Parties as set forth in writing.

"Law" shall mean any applicable treaty, statute, code, constitutional provision, ordinance, rule, regulation, order, judgment, decree, decision, injunction, process or any similar form of legally binding decision or directive issued by any Governmental Authority including permits and regulatory approvals and any applicable common law.

"Legal Requirement" shall mean any obligation of AEPCO or TRANSCO required by Law.

"Load Forecast" shall mean he projections of monthly coincident peak kilowatt and total monthly kilowatt-hour loads of a party to an Agreement.

"Load Growth System Facility" shall mean any System Facility or portion thereof that is not an All Requirements Resource Facility or a Resource Facility and is constructed or acquired by TRANSCO to deliver the power and energy of any Future Resource or Resource Modification to All Requirements Members for serving the portion of total load of All Requirements Members that is in excess of the sum of the collective AC of All Requirements Members in Existing Resources with all Power Sales Resources reduced to zero.

"Load Pool" shall mean those Pooled Loads served from Pooled Resources.

"Load Ratio Share" shall have the meaning set forth in the TRANSCO Tariff.

"Load Ratio Share of PRM*" shall mean the ratio, expressed as a decimal, that results from dividing: (i) the demand of PRM* AEPCO Load at the time of the TRANSCO system Peak, by (ii) the sum of: (a) the actual total of the demands of all firm loads of all TRANSCO

customers at the time of the TRANSCO system peak, including PRM* plus (b) the reserved transmission capacity of all TRANSCO customers receiving firm point to point transmission service under the TRANSCO Tariff, less (c) the actual demands at the time of the TRANSCO system peak of the loads of TRANSCO's customers receiving firm point to point transmission service under the TRANSCO Tariff. Such ratio shall be calculated on a rolling twelve month basis.

"Long Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period extending beyond the subsequent five calendar years.

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

"MEC" shall mean Mohave Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Member" shall mean a member of AEPCO, a CSP Member or a TRANSCO Member, as applicable.

"Member Actual AEPCO Load Data" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member AEPCO Load Forecast" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member Agreement" shall mean the Member Agreement as executed and delivered by and among the Class A Members, AEPCO, TRANSCO and CSP, dated July 2, 2001.

"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's Member Peak Demand purchased by Member from AEPCO pursuant to a PRM* Partial Requirements Capacity and Energy Agreement, which consists of the demands of PRM* AEPCO Load and PRM* AEPCO Sales.

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

"Member JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses of loads located within a Member's Distribution Service Area served using capacity and energy provided by CSP as a result of a Joint Marketing Agreement between CSP and a Class A Member, for which CSP purchases capacity and energy from AEPCO.

"Member Transaction" shall mean (i) the consolidation or merger by the Partial Requirements Member with any other Person; (ii) the reorganization or change of the form of the Partial Requirements Member's business organization from an electric cooperative non-profit membership-owned corporation; or, (iii) the sale, transfer, lease, or other disposal of all or substantially all the Partial Requirements Member's assets to any Person (or any effort or agreement therefor), whether accomplished in a single transaction or contemplated through a series of transactions as set forth in Section 12 of the Partial Requirements Capacity and Energy Agreement and the Transmission Agreement.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member's Distribution Service Area" shall mean the geographical electric service territory of a Class A Member as certificated by the ACC, the California Public Utility Commission or the New Mexico Public Utility Commission, as applicable, to supply distribution service as well as all other territory so served by such Class A Member pursuant to applicable Law, or any inter-utility border agreement.

"Merchant Purchase(s)" shall mean a wholesale purchase of capacity and/or energy (pursuant to Section 11 herein) for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to: (i) minimize the cost of energy production from Pooled Resources, and (ii) displace energy from Pooled Resources of higher Pool Price.

"Merchant Sale(s)" shall mean a wholesale sale of capacity and/or energy (pursuant to Section 11 herein) from Surplus Resources for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to use Surplus Resources for the economic benefit of the Pool Resource Owners.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Minor Resource Modification" shall mean an addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of an AEPCO Power Purchase Resource for five years or less, undertaken by AEPCO in its sole discretion, which will not: (i) increase of greater than ten percent the capacity of the AEPCO Resource being modified; (ii) result in an increase of greater than five percent in AEPCO's Revenue Requirement From AEPCO's Class A Members upon the operation of such addition, improvement, repair and modification or extension, as the case may be; or, (iii) extend the term of any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement.

"Must-Pool Load(s)" shall mean those loads of AEPCO, CSP and MEC which Section 3 herein requires be served from the Resource Pool.

"Must-Pool Resources" shall mean AEPCO Resources and those Resources of CSP and the Partial Requirements Member, which are required to be included in the Resource Pool.

"Native Load" shall mean (i) for AEPCO, the electric load of wholesale power customers of AEPCO on whose behalf AEPCO, by Law, tariff or contract, has undertaken an obligation to construct, or otherwise obtain, reliably operate and provide AEPCO Resources (including Purchase Power Resources of AEPCO) to meet the electric requirements of such customers and shall include, but not be limited to, AEPCO Delivered Load, (ii) for TRANSCO, "Native Load" shall mean the electric loads of the TTS customers on whose behalf TRANSCO, by Law, tariff or contract (including as TTS successor to AEPCO) has undertaken an obligation to construct and operate the TTS and shall include, but not be limited to, AEPCO Delivered Load, and (iii) for a Member, "Native Load" shall mean the electric load of the customers of a Member to whom such Member sells power and/or energy and on whose behalf the Member, by Law, tariff, or contract, has undertaken an obligation to construct, or otherwise obtain, and reliably operate the Member's system to meet the power supply requirements of such customers.

"Near Term" shall mean" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period not to exceed the subsequent two calendar years.

"NERC" shall mean the North American Electric Reliability Council, or entity or agency succeeding to its powers and functions.

"Net Utility Plant" shall mean total utility plant less accumulated depreciation as computed consistent with Accounting Requirements.

"Network Integration Transmission Service" shall described in Part III of the TRANSCO Tariff.

"Network Loads" shall have the meaning set forth in Section 1 of the TRANSCO Tariff. The Delivery Points of the Network Loads of Member served pursuant to this Agreement are set forth in Schedule C hereto.

"Network Loss Factor" shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

"Network Resources" shall have the meaning set forth in Section 1 of the TRANSCO Tariff.

"Network Service Agreement" shall mean the Network Service Agreement by and between TRANSCO, AEPCO and the All Requirements Members, substantially in the form attached as Exhibit B-1 to the Member Agreement.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Non-Generation Assets" shall mean as determined in accordance with Accounting Requirements, all assets of AEPCO of every kind, description, and location which shall be acquired by TRANSCO from AEPCO, as of the Closing Date, which are set forth in Schedule 1 to the Restructuring Agreement.

"Non-Pool Loads" shall mean those loads of a Partial Requirements Member or CSP or applicable portions of such loads which are not included in Pooled Loads.

"Non-Pool Resource" shall mean any Resource obtained by a Partial Requirements Member or CSP and which is not included in the Resource Pool.

"O&M" shall mean the general accounting term used to describe activities and expenses involved with the use, operation, maintenance and repair of a cooperative's plant and facilities including expenses associated with activities intended to prevent or remedy an impending or actual breakdown of those facilities. The term O&M does not include the enlargement or improvement of the property owned or leased and operated by a cooperative nor does it include the replacement of retirement units.

"O&M Charge" shall mean the charge computed in accordance with 5.3 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Off-Peak Hours" shall mean those hours defined by the Western Systems Coordinating Council to represent off-peak load periods, which for each day consist of the eight hours of the hour ending at 2300 through hour ending at 0600, Mountain Standard Time, and the remaining hours of each Sunday and of each of six holidays (New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day).

"Operating Committee" shall mean the standing committee(s) established in the Partial Requirements Capacity and Energy Agreement and assigned by the parties thereto to deal on a prompt and orderly basis with certain technical and operating issues that may arise in connection with system development or operations.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Optional Pool Resources" shall mean those Resources which a party may commit to the Resource Pool.

"Order No. 888" shall mean that certain FERC order Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. para. 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. para. 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC para. 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC para. 61,046 (1998).

"Order No. 889" shall mean that certain FERC order Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs. para. 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & Regs. para. 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC 61,253 (1997).

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period,

as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean, Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Peak Hours" shall mean all hours of each day which are not Off-Peak Hours.

"Performance Default" shall meant the default by either party to a Partial Requirements Capacity and Energy Agreement, a Transmission Agreement, a Network Service Agreement, or a Joint Marketing Agreement, whereby, as provided by the terms of each such Agreement, such party fails to comply, after any notice of such failure and opportunity to cure, with any of the respective terms, conditions, obligations or covenants of such Agreement.

"Person" shall mean an individual, partnership, association, limited liability company, corporation, membership corporation, business trust, joint stock company, trust, cooperative, unincorporated organization, joint venture, or other entity.

"PGR Purchase Agreement" shall mean the Power Purchase Agreement between Panda Gila River, L.P., and AEPCO, dated April 15, 2003, as amended.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Planning Services" shall mean bulk power supply planning and Future Resource procurement services.

"Pool Price" shall mean the price, in mills/kWh, established for a Pooled Resource pursuant to Appendix A-2 of the Resource Pooling Policies.

"Pool Resource Owner" shall mean a Party that has committed Resources to the Resource Pool pursuant to Section 4 herein.

"Pooled Loads" shall mean the aggregate total electric load and sales of the parties that are to be served by Pooled Resources, including distribution losses and not including reserves or transmission losses.

"Pooled Resources" shall mean those Resources which have been committed to the Resource Pool.

"Possible Selling Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Factor" shall mean the cosine of the phase angle between the voltage and the current. Power Factor can be lagging or leading indicating whether the current is lagging or leading the applied voltage.

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

"Power Purchase Resource" shall mean capacity and energy or energy purchased by a party under a contract with a term greater than one year, including any such capacity and energy or energy purchased or acquired pursuant to (i) the Public Utility Regulatory Policies Act of 1978, as it may be amended from time to time, or (ii) the Environmental Portfolio Standard set forth in A.A.C. R14-2-1618, as it may be amended from time to time, as adopted by the Arizona Corporation Commission.

"Power Sale(s)" shall mean a wholesale sale of capacity or energy for a term of one year or more. Power Sales do not include Retail Sales.

"Power Sales Load" shall mean the demand and energy requirements of the load associated with Power Sales Resource(s).

"Power Sales Resource" shall mean a sale of capacity and energy from Existing Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

"Power Sales Resource Demand Revenues" shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Power Sales Resource Energy Revenue" shall mean, for a billing period, the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period

"Power Sales Resource System Facility" shall mean any System Facility or portion thereof that is required to enable delivery of capacity and energy to Class A Members from expired Power Sales Resources which existed as of the Effective Date.

"Pre-Closing" shall mean the execution and delivery of all documents that are a condition to Closing, as further described in the Closing Memorandum.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"Pre-Schedule Day" shall mean the day on which a Pre-Schedule must be submitted for the next Scheduling Day.

"PRM" shall mean a Partial Requirements Member.

"PRM*" shall mean a term in definitions which may be replaced with the name of a PRM so that the definition would apply only to the specified PRM (see Section 3.8 above).

"PRM* 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 (or served from line extensions therefrom) for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement, but shall not include PRM* Wheeling Load. Such demand and energy requirements are included within PRM* Metered kW and PRM* Metered kWh. The demand component of PRM* AEPCO Load numerically consists of the coincident aggregate, at a specific time, of: (i) PRM* Metered kW; less (ii) kW of PRM* Wheeling Load; less (iii) kW of Member JMP Load of PRM*; less (iv) kW of CSP JMP Load of PRM*; (v) less Kw of PRM* Internal Load. The energy component of PRM* AEPCO Load numerically consists of the aggregate during a specific time interval of: (i) PRM* Metered kWh; less (ii) kWh of PRM* Wheeling Load; less (iii) kWh of Member JMP Load of PRM*; less (iv) kWh of CSP JMP Load of PRM*; less, (v) kWh of PRM* Internal Load.

"PRM* 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 PRM* to wholesale buyers or to end use loads which are external to Member's Distribution Service Area of PRM* for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement. The demand and energy requirements of PRM* AEPCO Sales shall be metered (or determined) as agreed between PRM* and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery.

"PRM* External Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located external to the Member's Distribution Service Area of PRM* (and not served from line extensions therefrom) for which PRM* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* External Load are not included in PRM* Metered kW and Member* Metered kWh, respectively.

"PRM* Internal 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 PRM* (or served from line extensions therefrom) for which Member* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* Internal Load are included in PRM* Metered kW and PRM* Metered kWh, respectively.

"PRM* Metered kW" shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Metered kWh " shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and PRM*.
"PRM* Resource(s)" shall mean a Resource of a Partial Requirements Member of AEPCO; PRM* Resource does not include the capacity and energy purchased from AEPCO under the PRM* Partial Requirements Capacity and Energy Agreement, or purchased by AEPCO under separate contract.

"PRM* Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and PRM* for the purposes of PRM* Transmission Service.

"PRM* Transmission Service" shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load.

"PRM* Wheeling Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within Member's Distribution Service Area of PRM* (or served from line extensions therefrom), which are supplied by capacity and energy from third parties (and not from Member Resources or the AC of PRM*) and for which PRM* provides delivery services over its

distribution system. The demand and energy requirements of PRM* Wheeling Load are included within PR* Metered kW and PRM* Metered kWh, respectively.

"Project Approval" shall mean the approval required by Section 3.4.5 of the Partial Requirements Capacity and Energy Agreement for a Resource Modification.

"Proposal and Analysis" shall have the meaning set forth in Section 3.4.3 of the Partial Requirements Capacity and Energy Agreement.

"Prudent Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to include a spectrum of possible practices, methods, or acts generally acceptable in the region that could be expected to accomplish the desired result at a reasonable cost consistent with reliability, safety and expedition in light of the circumstances.

"Purchasing Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Rate Schedule A" shall mean the Schedule A to the Partial Requirements Capacity and Energy Agreements or to an Existing Wholesale Power Contract.

"REAct" shall mean the Rural Electrification Act of 1936.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Receipt Point" shall mean the interconnection between the TTS and the transmission, sub-transmission, generating resource or distribution facilities at which TRANSCO is to accept capacity or energy from AEPCO Resources for delivery pursuant to the Transmission Agreement or Network Service Agreement, and from which TRANSCO provides transmission service to the Delivery Point.

"Reliability System Facilities" shall mean System Facilities and/or improvements that are constructed and installed or acquired by TRANSCO to enhance or maintain the reliability of the TTS as required by the transmission system performance criteria of the NERC, as applied within the WECC, consistent with Prudent Utility Practice.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing

period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Remaining Equity Investment of TRANSCO" shall mean that portion of the installed cost of a System Facility or Direct Assignment Facility financed by an equity contribution of TRANSCO (with interest accrued thereon) which remains undepreciated on the Last Service Date (or the date of closing of a transaction between the parties involving the disposition of a Direct Assignment Facility).

"Remaining Indebtedness of TRANSCO" shall mean the principal balance remaining unamortized as of the Last Service Date (or the Date of Closing of a transaction between the Parties involving the disposition of a Direct Assignment Facility) of that portion of the installed cost of a System Facility or Direct Assignment Facility financed by TRANSCO debt, with interest accrued thereon, which remains unamortized on the Last Service Date or termination or exercise of an option to purchase the Direct Assignment Facilities serving SSVEC (plus any actual prepayment penalties incurred from the prepayment of such debt).

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"Required Modification" shall have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.
"Resource" shall mean either a Generating Resource or Power Purchase Resource.

"Resource Acquisition" shall mean the performance of analyses of Resource needs or Resource sales proposals, the recommendation of a Power Purchase Resource or Generating Resource, and the negotiation of and acquisition for AEPCO of a Resource.

"Resource Deficiency" shall mean a deficiency in AEPCO Resources available to serve Class A Members and Power Sales Loads.

"Resource Facility" shall mean any System Facility, or portion thereof, or Direct Assignment Facility required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future Resource in which SSVEC has all ACP.

"Resource Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending upon the earlier of:(a)the twentieth anniversary thereafter or (b) the last service date of a Class A Member's Wholesale Power Contract, as set forth in the Resource Planning Policies.

"Resource Integration Agreement" shall mean the multi-party agreement by and between CSP, TRANSCO, AEPCO and MEC and dated July 2, 2001, as amended to include SSVEC and TRICO as parties.

“Resource Modification” shall mean any addition, improvement, repair or modification to a Generating Resource or the modification or extension of the term of an existing Power Purchase Resource made by AEPCO which would: (i) increase the capacity of the AEPCO Resource by more than ten percent; or (ii) result in an increase of more than five percent in AEPCO's Revenue Requirement upon the operation of such addition, improvement, repair and modification, or extension, as the case may be, or (iii) require an extension of the term of an Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement. A Resource Modification shall not be construed to include a Minor Resource Modification.

“Resource Operation Policies” shall mean the resource operation policies set forth in Schedule B to the Resource Integration Agreement and Exhibit B2 to Schedule B of the Partial Requirements Capacity and Energy Agreement.

“Resource Planning” shall mean the process used to identify a deficiency in the amount of existing Resources needed to reliably meet anticipated load requirements (including reserves). Resource Planning includes a review of alternative Resources and the selection of the preferred Resources to be constructed or acquired to meet the deficiency.

“Resource Planning Policies” shall mean the resource planning policies set forth in resource planning and acquisition documents.

“Resource Pool” shall mean the capacity and energy pool which integrates the electric capacity and associated energy of AEPCO Resources with Resources owned or contracted for by the Partial Requirements Members and CSP, which the Partial Requirements Member or CSP is required to include or has designated for inclusion in such pool.

“Resource Pool Operation” shall mean that load and resource integration service provided by AEPCO.

“Resource Pooling Policies” shall mean the resource pooling policies set forth in Schedule A of the Resource Integration Agreement.

“Resource Pre-Schedule” shall mean a schedule of energy needed from the Resources of the Resource Pool to meet the aggregate of the Pooled Loads made on a least energy cost and a day-ahead basis.

“Restructuring Agreement” shall mean the Restructuring Agreement as executed and delivered by and among AEPCO, TRANSCO and CSP, dated the 11th day of October 2000.

“Retail Sales” shall mean sales arranged or made by CSP in the competitive retail electric market, including sales at retail from Surplus AEPCO Resources. Retail Sales do not include Power Sales.

“Revenue Shortfall” shall mean the failure of a cooperative to receive sufficient revenue to cover its revenue requirement.

"Rights of Way" shall mean the various rights of way and easements held by TRANSCO from time to time.

"RUS" shall mean the Rural Utilities Service, as successor-in-interest to the Rural Electrification Administration, which is an agency of the United States Department of Agriculture, or any agency of the Government succeeding to its powers and functions

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as a S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduled Day" shall mean the Scheduling Day, as defined by WECC, for which a Pre-Schedule has been submitted.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Scheduling Party" shall mean the owner of an Optional Pool Resource that qualifies to be a Pooled Resource but is not included in the Resource Pool and which is separately scheduled by such owner.

"SEC" shall mean the Securities and Exchange Commission, or any agency of the Government succeeding to its powers and functions.

"Separation of Functions and Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct referenced in Section 15 of the Resource Integration Agreement and set forth as Schedule F attached thereto.

"Service Agreement" shall mean the agreement entered into by a transmission customer or network customer and TRANSCO for transmission service or network service under Part II or Part III respectively, of the TRANSCO Tariff.

"Service Agreement(s) for Firm and Non-Firm Transmission and Ancillary Services" shall mean any Service Agreement by and between TRANSCO and AEPCO for transmission

service pursuant to Part II of the TRANSCO tariff, substantially in the form of agreement attached to the TRANSCO Tariff.

"Short Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period greater than the subsequent two calendar years but lasting less than five calendar years.

"Southwest" shall mean TRANSCO.

"SSVEC" shall mean Sulphur Springs Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Staffing Agreement" shall mean each of the individual staffing agreements whereby CSP shall furnish personnel services to TRANSCO or AEPCO, respectively.

"Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct as set forth as Schedule F to the Resource Integration Agreement.

"Stranded Costs" shall mean any actual charge or cost (including any transmission or distribution surcharges, fee, competition transition charge, wires charge, adjustment, rate, system benefit charge, regulatory charge, regulatory asset surcharge, exit fee or any other mechanism or systematic recovery program approved for use for the recovery of stranded investments) that are permitted by the ACC pursuant to the ACC Electric Competition Rules, A.A.C. R14-2-1601, et seq. or successor rule, or otherwise assessed or levied in order to recover the expenses and liabilities associated with stranded investments including without limitation, regulatory assets, or costs associated with the introduction of competition in the retail sales of electric energy and capacity.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase

"Supplemental Energy Intrachange" shall have the meaning set forth in Section 6 of the Resource Pooling Policies.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made by AEPCO for a period of less than a year to serve load of CARM or a Member* CA Planning Contract Member in excess of CARM's or such Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Surplus AEPCO Resource(s)" shall mean AEPCO Resources available and not necessary or used to serve AEPCO Total Load.

"Surplus Resource" shall mean a Pooled Resource(s) that is surplus to Pooled Load and its operating reserves as determined by a Pool Resource Owner in accordance with Prudent Utility Practice.

"System Facilities" shall mean the transmission lines, substation facilities or components thereof and firm wheeling purchased by TRANSCO, which do not constitute Direct Assignment Facilities and are used to deliver capacity and energy to the Members and other transmission customers of TRANSCO.

"Tag" shall mean the collection of information in the electronic form of request and subsequent response as part of the process implemented by the North American Electric Reliability Corporation for electronically communicating a request for, securing approval of, and recording an energy transaction via the Internet.

"Tariff" shall mean at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sale" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported by AEPCO as an economy sale to RUS Uniform System of Accounts Number 447.

"Times Interest Earned Ratio" or "TIER" " shall mean the financial ratio determined based on figures shown on Form 12 Balance Sheet for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) net

patronage capital or margins and (b) Interest Expense on long-term Indebtedness, and (2) dividing the sum obtained by Interest Expense on long-term Indebtedness.

"Total Assets" shall mean an amount constituting the total assets of a Class A Member determined in accordance with Accounting Requirements.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

"TRANSCO", which is also known as "Southwest", shall mean Southwest Transmission Cooperative, Inc., a non-profit corporation organized under the Laws of the State of Arizona.

"TRANSCO Assumed AEPCO Debt" shall mean that portion of AEPCO's Indebtedness that TRANSCO assumes pursuant to the TRANSCO CFC Note (if required), the TRANSCO FFB Note(s), the TRANSCO RUS Note(s) and the TRANSCO Assumption and Indemnity Agreements, in each case, in accordance with applicable Law.

"TRANSCO Assumption and Indemnity Agreements" shall mean collectively the Assumption and Indemnity Agreements between TRANSCO and AEPCO and the trustees of certain financial instruments, the forms of which are set forth in Appendix A to the Restructuring Agreement pursuant to which TRANSCO will agree to assume the obligation to pay that portion of AEPCO's debt secured under the AEPCO Mortgage that AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO By-laws" shall mean the By-laws, in the form adopted by the TRANSCO Board of Directors or the TRANSCO Members, as appropriate.

"TRANSCO Employees" shall mean all persons employed by TRANSCO, including TRANSCO Management and systems operations personnel designated by the chief executive officer of TRANSCO, but shall not include persons employed by CSP or any other contractor.

"TRANSCO FFB Note(s)" shall mean the note(s) in the form required by FFB pursuant to which TRANSCO will assume and replace AEPCO as an obligor with respect to that portion of AEPCO's Indebtedness to the FFB outstanding as of the Effective Date that each of

AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO Member" or "Southwest Member" shall mean any of the Class A Members of TRANSCO, and others, including AEPCO and CSP, that become members of TRANSCO in accordance with the TRANSCO By-laws.

"TRANSCO Mortgage" shall mean the Mortgage and Security Agreement, dated as of the Effective Date, made by and among TRANSCO, RUS and CFC which secures the TRANSCO Secured Obligations.

"TRANSCO Notes" shall mean written instruments or notes which evidence the obligation of TRANSCO for its assumption of a portion of the AEPCO Indebtedness (the TRANSCO Assumed AEPCO Debt) to purchase the Transmission Business as evidenced and effected by delivery of the TRANSCO FFB Note(s) and the TRANSCO RUS Note(s), payable to or guaranteed by the Government, acting through the RUS, and by its assumption of the repayment obligations of a portion of the loans made by, or securities issued to, or obligations undertaken to the Financial Entities, and which in the future will also include written instruments which may evidence additional or new loans or advances TRANSCO may obtain to finance the construction or purchase of new facilities for the TTS or the modification of existing TTS facilities, as applicable.

"TRANSCO RUS Note" shall mean the simple allocation of the AEPCO Note owed to RUS.

"TRANSCO Secured Obligations" shall mean collectively, the TRANSCO Notes, certain of the loans made by others to TRANSCO, or securities issued to others by TRANSCO, or debt obligations entitled to the lien created by the TRANSCO Mortgage.

"TRANSCO Tariff" or "Southwest Tariff" shall mean the open access transmission tariff under which transmission services and Ancillary Services are offered by TRANSCO.

"TRANSCO Transmission System" or "TTS" shall mean the electric transmission system of TRANSCO including all transmission lines, substations, microwave and telecommunication facilities, system control and data acquisition system, inventories, works in progress, contract rights to provide or receive transmission services, leases, interests in joint transmission projects, licenses, other related transmission agreements and all other such transmission related assets.

"Transferee" shall mean any of the following Persons: (i) the Person formed as a result of a Member Transaction by any consolidation of the Partial Requirements Member with any other Person; (ii) the survivor of any merger or reorganization of the Partial Requirements Member; (iii) or a Person that acquires or leases all or substantially all of the electric assets of the Partial Requirements Member.

"Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and a Partial Requirements Member.

"Transmission Business" shall mean the performance of transmission services and Ancillary Services, and the ownership and use of any rights, obligations, duties, approvals and licenses to the Non-Generation Assets, including the Transmission Resources, and shall include responsibility for the Non-Generation Liabilities.

"Transmission Forecast" shall mean with respect to any Person, such Person's forecast, on an annual basis, of its transmission requirements from TRANSCO.

"Transmission Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending at least the tenth anniversary thereafter.

"Transmission Planning" shall mean the process by which the performance of an electric transmission system is evaluated with respect to specified load-serving capability in accordance with Prudent Utility Practice and by which future modifications, improvements and additions to such electric transmission system are determined by TRANSCO.

"Transmission Requirements Study" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TRICO" shall mean Trico Electric Cooperative, Inc., an electric cooperative non-profit corporation organized and existing under the Laws of the State of Arizona.

"TRS Work Plan" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TSEPP" shall mean TSE Promotional Products, Inc., an Arizona corporation.

"TTS" shall mean TRANSCO Transmission System.

"WECC" shall mean Western Electricity Coordinating Council, a regional division of NERC, and successor to WSCC.

"Wholesale Power Contract" shall mean a contract, including its amendments and modifications, including the Existing Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement, between AEPCO and a Class A Member of AEPCO, for the wholesale sale by AEPCO of electric power or electric power and transmission services to such Class A Member.

"Withdrawal Agreement" shall mean the form of withdrawal agreement attached to the Member Agreement as Exhibit D.

"WSCC" shall mean Western System Coordinating Council, a regional division of NERC.

ATTACHMENT 2 to Third Amendment to Partial Agreement

Partial Requirements Members Rate Schedule A

Partial Requirements Members

RATE SCHEDULE A
Dated May 11, 2010

1. INTRODUCTION:

This Rate Schedule A specifies the rates and charges and the methodology for developing and administering those rates and the charges for capacity and energy sales made by AEPCO to Member pursuant to its 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 charges which are currently in effect in accordance with the Agreement. Exhibit A-2 specifies the methodology for calculating the rates and charges, 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 the methodologies for determining billing units, energy rates and energy charges using cost causation principles. Exhibit A-6 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 Existing Resources, the S&G PPA and Supplemental Purchases (the "Dispatch Pool Resources"). AEPCO may include the Dispatch Pool Resources in a larger pool for dispatch purposes, provided that the Billing Unit Program is maintained pursuant to Exhibit A-4 and the rights and benefits of each Class A Member are not diminished. No additional members may be added to the existing Class A Members with rights in the Dispatch Pool Resources, and changes in the membership shall be subject to Sections 12 and 13 of the Agreement.

AEPCO shall not enter into contracts for or acquire (i) any new AEPCO Generating Resource; or (ii) any AEPCO Power Purchase Resource with a term of greater than one year, unless AEPCO has first entered into a written agreement between AEPCO and all Class A Members agreeing to participate in such Resource, under which no related direct and indirect costs, charges and revenues derived from such Resource would be assigned to any non-participating Class A Members.

2. CONDITIONS OF SERVICE:

2.1 Applicability.

The rates, charges, and adjustments and the methodology for setting and adjusting such rates, charges and adjustments are set forth in this Rate Schedule A. Member shall make payment for electric service under the Agreement through the rates, charges and adjustments established by AEPCO in accordance with the Agreement and this Rate Schedule A. Member shall remain obligated at all times during the term of the 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 Adjustment.

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

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

Where:

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

2.3 Demand Overrun Adjustment.

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

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

Where:

doaf	=	demand overrun adjustment factor
mbdkW	=	Member Schedule in kW or Metered kW less capacity from sources outside the Dispatch Pool, as applicable, and
AC	=	Allocated Capacity of Member, in kW.

2.4 Taxes and/or Assessments.

The rates and charges 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 charges. 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 charges for capacity and energy sales for payment by Member.

2.5 Charges.

The monthly charge billed to 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 as set forth in Exhibit A-1 hereof; plus,

3. the Base Energy Charge and Base Fuel Cost Adjustor Charge, calculated as set forth in Exhibit A-4; plus

4. the Other Energy Charge and Other Fuel Cost Adjustor Charge, calculated as set forth in Exhibit A-4; plus

5. any Power Factor Adjustment pursuant to Section 2.2 hereof; plus,

6. any Demand Overrun Adjustment pursuant to Section 2.3 hereof; plus,

7. all taxes and/or assessments pursuant to Section 2.4 hereof, if any; plus

8. 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 the Agreement, including this Rate Schedule A, is attached to this Rate Schedule A as Exhibit A-6 and made a part hereof. Actual billings made by AEPCO to Member pursuant to Section 5.1 of the 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 charges set forth in Exhibits A-1 to Rate Schedules 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 charges as set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members do not provide revenues sufficient, but only sufficient, to satisfy AEPCO's Revenue Requirements from Class A Members, the Board of Directors of AEPCO shall establish new rates and new charges for electric service to Member pursuant to the procedures set forth in Section 5.6 of the Agreement and otherwise comply with those provisions pertaining to rates and the charges as set forth in Section 5 of the Agreement. Such new rates and charges established in conjunction with new rates and charges for all other Class A Members shall be submitted to the RUS and shall become effective unless they have been disapproved in writing by the RUS, and Exhibits A-1 (and other Exhibits, as may be applicable) to Rate Schedules A shall be modified to reflect such new rates and charges in effect.

3.2 Development of Cost of Service and Revenue Requirement.

AEPCO rates and the charges developed under this Rate Schedule A for charging Member and rates and charges for charging 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 proposed rates and charges based on such cost of service studies and Revenue Requirement are approved by the AEPCO Board of Directors. 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., data shall be 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 all Class A Members shall be developed pursuant 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, or energy as set forth in Exhibit A-2 and depicted in Exhibit A-3 hereto.

3.4 Development of Rates, Charges, and Billing Determinants.

Once the components of fixed, O&M, and energy of AEPCO's Revenue Requirement from All Class A Members are determined pursuant to Section 3.2, and all expenses are classified pursuant to Section 3.3, the rates and charges for electric service pursuant to the Agreement shall be determined in accordance with Exhibit A-2. The billing determinants for Member's Fixed Charge and Member's O&M Charge shall be the ACP as specified in Section 3.5 below. The billing determinants for the energy rates shall be determined pursuant to Exhibit A-4 and as set forth in Section 5.4 of Exhibit A-2.

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 and O&M Charge for Member. Appendix B to Exhibit A-5 to this Rate Schedule A identifies AEPCO Resources in the Dispatch Pool as well as the Allocated Capacity (AC) for Member.

Exhibit A-1 to Rate Schedule A
Partial Requirements Member
Rates and Fixed Charge
(Effective as of Agreement Date)

Fixed Charge	$ per month *
O&M Charge	$ per month *
Energy Rates:	
Base Energy Rate	$_______ per kWh * of base resources used during the billing period.
Other Energy Rate	$_______ per kWh * of other resources used during the billing period.
Power Cost Adjustor Rate for FPPCA:	
Base Resources	$_______ per kWh *
Other Resources	$_______ per kWh *

*based on test year data with pro forma adjustments as approved by the ACC.

Partial Requirements Members
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 charges applicable for AEPCO Resources in which Member has an ACP. This methodology shall be applied to AEPCO expenses and revenues described herein which are maintained under the RUS 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 charges 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 Member through charging the rates and charges developed pursuant to the Agreement, plus (ii) revenues to be recovered from other Partial Requirements Members through rates and charges pursuant to their Partial Requirements Capacity and Energy Agreements; plus (iii) revenues to be recovered from the All Requirements Members through rates and charges pursuant to their Existing Wholesale Power Contracts, plus (iv) 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 RUS 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 under the RUS Uniform System of Accounts by AEPCO 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 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 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 classified as either: (a) Credits-F, (b) Credits-O, or (c) Credits-E.

Margins shall be classified and assigned to the fixed category.

2.2 Depiction.

The expense and revenue accounts and their classification into fixed, O&M and energy 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 charges attributable to electric service under the 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 Charge 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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Account 403	(Depreciation & Amortization Expense),
Account 408	(Ad Valorem Taxes),
Accounts 427-428	(Interest on Long Term Debt, Interest Charged to Construction, 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),
Plus 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 Accts 447-456	(Credits – F) which include: (a) a portion of the revenues from Power Sales Resources, consisting of total Power Sales Resources' revenues less Power Sales Resources' energy revenues, to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such revenues; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services, but excluding the sales of power in subparagraph a above; such portion to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such net revenues.

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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

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), and
Accounts 920-923	(Administrative & General I-O only),
Account 924	(Administrative & General II-O only),
Accounts 925-926	(Administrative & General III-O only), and
Accounts 927-932	(Administrative & General I-O only).
Less Accounts 447-456	(Credits-O) consisting of: (a) Scheduling Revenues - The scheduling revenues resulting from providing scheduling and trading services for customers other than Class A Members of AEPCO, excluding energy-related revenues, to be credited in an amount equal to the product of the total of such revenues multiplied by the ACP of the Member; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services; such portion to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such net revenues.

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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Accounts 501 and 547	(Fuel-E only),
Accounts 555	(Purchased Power-E only),
Account 565	(Wheeling Power-E only),
Accounts 920-923	(Administrative & General I-E only),
Account 924	(Administrative & General II-E only),
Accounts 925-926	(Administrative & General III-E only), and
Accounts 927-932	(Administrative & General I-E only),
Less Accounts 447-456	(Credits-E only).

5.0 MEMBER RATES AND CHARGES:

5.1 Elements.

The rates and charges for electric service under the Agreement to Member shall consist of (a) the Fixed Charge, composed of an appropriate allocated fixed capacity component, including a margin, (b) an O&M Charge, (c) Base Energy Rate, and (d) Other Energy Rate.

5.2 Fixed Charge.

The monthly Fixed Charge for Member, stated in dollars, shall equal: the quotient of (a) the product of (i) 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 caused by failures of Class A Members to meet their portion of AEPCO's Revenue Requirement, multiplied by (ii) the ACP of Member, (b) divided by twelve (12) to convert to a monthly charge.

5.3 O&M Charge.

The O&M Charge for Member shall be equal to the quotient of (a) the product of (i) the annual test year O&M component as calculated in Section 3.3 of this Exhibit A-2, multiplied by (ii) the ACP of Member, (b) divided by twelve (12) to convert to a monthly charge.

5.4 Base Energy Rate and Other Energy Rate.

The Base Energy Rate and Other Energy Rate for Member shall be established based on the methodology contained in Exhibit A-4, and shall together equal the energy component comprised of the expenses, less revenue credits as identified in Section 4.0 of this Exhibit A-2 and calculated pursuant to the methodology in Exhibit A-4, divided by the aggregate test year energy billing units (stated in kWh) developed pursuant to Exhibit A-4 in the cost of service study for the Class A Members, adjusted for known and measurable changes.

6.0 REVENUE SHORTFALLS:

Any deficiencies or shortfalls in collections of AEPCO's Revenue Requirement from Class A Members will be recovered through appropriate adjustments to: (a) the O&M Charge, or (b) the margin included in the Fixed Charge. An adjustment will be made to the O&M Charge 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 Charge 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 charges shall be based on Schedules or on metered data at the Delivery Points. 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 and charges 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.

Partial Requirements Members
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	
	Maintenance:			

[1]All fuel related costs are assigned to the energy classification, except for 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)
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]
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]

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[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)
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		
447-456	Operating Revenues from Other Sources – Credit	X(7)	X(7)	X(7)
	Margin Component	X		

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[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.

[7]Excluding revenue from Power Sales Resources, revenue from sources other than AEPCO's Class A Members shall be credits to the Fixed component and to the O&M component in amounts proportionate to Fixed Revenue Requirements and O&M Revenue Requirements.

Exhibit A-4 to Rate Schedule A
Determination of Billing Units, Energy Rates and Energy Charges Using Cost Causation Principles

1. INTRODUCTION:

This Exhibit A-4 sets forth the methodology for the determination of energy billing units, energy rates and energy charges for each of AEPCO's Class A Members using cost causation allocation principles.

2. DEFINITIONS:

The following terms are used in this Exhibit and its Appendices.

"ARM Energy Cost Responsibility Share" or "ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future

Scheduling Hour; and for each Billing Unit Entity having a percentage interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Caacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by its (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the

entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"CARM" or "Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources and in S&G PPA, as applicable to each All Requirements Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A to the ARM Wholesale Power Contracts.

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.
"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate" shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sales Price" shall mean, for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy.

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G PPA Billing Energy and Supplemental Billing Energy.

"Federal Hydro Power Agreement(s)" shall mean 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 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).

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Network Loss Factor" shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period, as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Sales Resource Demand Revenues" shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Power Sales Resource Energy Revenue" shall mean, for a billing period the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"PRM" shall mean a Partial Requirement Member.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as an S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean, for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made for a period of less than a year to serve load of CARM or a Planning Contract Member in excess of CARM's or the Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by

AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Tariff" shall mean, at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sales" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported as an economy sale by AEPCO to RUS Uniform System of Accounts Number 447.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean, for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

3. <u>BILLING UNIT PROGRAM METHODOLOGY</u>:

The Billing Unit Program shall be assembled and maintained to reflect AEPCO's economic dispatch philosophy and priority as further set forth in Schedule B to the Partial Requirements Capacity and Energy Agreements. The Parties have divided and defined AEPCO Resources based on the respective interests therein as assigned under the Billing Unit Program, the definition of which is set forth in Appendix A to this Exhibit A-4, attached hereto and a part hereof.

The Billing Unit Program is established hereunder to account for hourly energy, separately for Daytime and Nighttime hours, first, for each Billing Unit Entity, its Minimum Other Capacity, then for each Billing Unit Entity having an ACP in S&G PPA or an interest in Supplemental Purchase, from its interests in Available Supplemental Capacity and Available S&G PPA Capacity (as dispatched by AEPCO under governing purchase contracts), then for each Billing Unit Entity its Available Base Capacity and finally its remaining Available Other Capacity. These hourly amounts for each Billing Unit Entity are assigned first to any Directed Sales of a Member* CA, to the loads of the CARM and Member* CA and to each Member*'s Total Schedule, but only to the extent required by the load of the CARM, by the Directed Sales and load of the Member* CA and by the Member*'s Total Schedule.

If a Billing Unit Entity has load or a Schedule that is not satisfied by its Available Base Capacity, Available Supplemental Capacity and Available S&G PPA Capacity, the Billing Unit Entity shall be assigned S&G And Supplemental Transfers and Base Transfers from other Billing Unit Entities' Excess S&G And Supplemental Capacity and Excess Base Capacity pursuant to the Billing Unit Program, proportionately based on the need of each Billing Unit Entity for Other Resources to the need of all Billing Unit Entities for Other Resources. To the extent a Billing Unit Entity still has load or a Schedule that is not satisfied, energy shall be assigned to it from its Available Other Capacity.

On the other hand, if a Billing Unit Entity has any Excess S&G And Supplemental Capacity or Excess Base Capacity, it shall be assigned pursuant to the Billing Unit Program proportionately based on available excess as S&G And Supplemental Transfers and Base Transfers. Then any Post-Transfer Base Capacity shall be assigned pursuant to the Billing Unit Program proportionately based on the amounts of such excess in the hour as Base Economy Sales, if any, or shall be assigned as Base Energy Mismatch or Other Energy Mismatch, as applicable.

Finally pursuant to the Billing Unit Program, the Other Economy Sales accumulated for the billing period will be allocated to each Billing Unit Entity proportionately based on each Billing Unit Entity's proportionate share of the billing period's accumulated totals of Post-Transfer S&G And Supplemental Capacity, each Member*'s Other Billing Energy, CARM Other Billing Energy, and each Member* CA's Other Billing Energy.

The Parties agree that all such assignments and allocations represent sale and purchase transactions to and from the Dispatch Pool Resources for which each Billing Unit Entity shall be credited or billed pursuant to Section 4 below.

Base Energy Mismatch and Other Energy Mismatch may occur due to operating conditions experienced during any billing period when the assignment and allocation of energy pursuant to the Billing Unit Program may be more or less than the amount of energy actually produced by the Dispatch Pool Resources; the causes of which may include, but are not limited to: (i) energy received from resources of third parties or provided to third parties for losses repayment; (ii) variations between loss accounting and actual hourly losses occurring on the system; (iii) energy interchange with other utilities; (iv) metering errors; and (v) inadvertent flows between AEPCO and its Balancing Authority. The Billing Unit Program shall compute for each billing period the total net Base Energy Mismatch and total Other Energy Mismatch and assign a credit or charge for the period, as applicable, which shall be recovered through the appropriate FPPCA.

The initial logic flow diagram of the Billing Unit Program is attached hereto as Appendices B through D to this Exhibit A-4 and is a part hereof. The Billing Unit Program shall be the sole and exclusive method for billing purposes of assigning energy billing units from Dispatch Pool Resources to Billing Unit Entities, and may only be modified by a written amendment agreed to by the CEOs of all Billing Unit Entities.

4. METHODOLOGY FOR DETERMINING TARIFF ENERGY RATES:

The following describes the method AEPCO shall use to formulate the Base Energy Rate and the Other Energy Rate.

4.1 Tariff Base Energy Rate.

The Base Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Base Energy Cost of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credits, Base Economy Sales Cost and Remaining Base Energy Cost, by (ii) each Billing Unit Entity's Base Billing Energy of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.1.1 The Base Energy Rate of each All Requirements Member shall be the same as the Base Energy Rate for CARM.

4.1.2 The Base Power Cost Adjustor Base for each All Requirements Member shall be the same as the Base Power Cost Adjustor Base determined for CARM.

4.1.3 The Base Billing Energy of each All Requirements Member shall be the product of (i) the Base Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

4.2 Tariff Other Energy Rate.

The Other Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Total Other Energy Cost of each Billing Unit Entity of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's applicable Base Transfer Purchase Cost, S&G PPA Energy Cost, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Transfer Sales Credit, Other Economy Sales Credit and its share of Base Mismatch Energy Credit, Base Mismatch Energy Charge, Other Mismatch Energy Credit, Other Mismatch Energy Charge and, if any, by (ii) the Total Other Billing Energy as applicable to each Billing Unit Entity for the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.2.1 The Other Energy Rate of each All Requirements Member shall be the same as the Other Energy Rate for CARM.

4.2.2 The Other Power Cost Adjustor Base for each All Requirements Member shall be the same as the Other Power Cost Adjustor Base determined for CARM.

4.2.3 The Total Other Billing Energy of each All Requirements Member shall be the product of (i) the Total Other Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

5. DETERMINING BASE AND OTHER ENERGY CHARGES:

5.1 Each billing period, AEPCO shall charge each Billing Unit Entity a Base Energy Charge, Base Fuel Adjustor Charge, Total Other Energy Charge and Other Fuel Adjustor Charge as defined in the Tariff. For each billing period, AEPCO shall compute each Billing Unit Entity's Base Over or Under Collection and Other Over or Under Collection for each billing period, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

5.1.1 Base Energy Charge: The Base Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Energy Rate as set forth in the Tariff.

5.1.2 Base Fuel Adjustor Charge: The Base Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.3 Base Over or Under Collection: The Base Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Base Adjustor Per Unit Cost and (ii) the sum of the Base Power Cost Adjustor Base plus the Base Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Base Billing Energy of each Billing Unit Entity for that period.

5.1.4 Other Energy Charge: The Other Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Energy Rate as set forth in the Tariff.

5.1.5 Other Fuel Adjustor Charge: The Other Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.6 Other Over or Under Collection: The Other Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Other Adjustor Per Unit Cost and (ii) the sum of the Other Power Cost Adjustor Base plus the Other Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Total Other Billing Energy of each Billing Unit Entity for that period.

6. ENERGY COST ACCOUNTING PROCESS:

The following describes the method of the Energy Cost Accounting Process (ECAP) AEPCO shall use to formulate for each billing period each Billing Unit Entity's Base Energy Cost, Base Fuel Adjustor Cost, Total Other Energy Cost and Other Fuel Adjustor Cost, from which AEPCO shall compute each Billing Unit Entity's Base Adjustor Per Unit Cost and Other Adjustor Per Unit Cost for the billing period, which shall be used to calculate for each billing period (i) Base Over and Under Collection and Other Over or Under Collection for such energy and (ii) fuel adjustor costs, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

The initial logic flow diagram of the ECAP is attached hereto as Appendices E and F to this Exhibit A-4 and is a part hereof.

6.1 Formulating Base Energy Cost.

For each billing period, the ECAP shall first compute the Coal Energy Cost and use it to calculate the Coal Energy Rate based on the Coal Energy Generated.

The ECAP shall then use Base Transfer for the billing period to compute, separately for Daytime and Nighttime, Base Transfer Sales Credit based on the Coal Energy Rate, and use Base Transfer Billing Energy to compute, separately for Daytime and Nighttime, Base Transfer Energy Cost, based on the Economy Purchase Rate. Using the billing units determined for the billing period pursuant to the Billing Unit Program, the Base Transfer Sales Credits and Base Transfer Energy Cost will then be allocated to each Billing Unit Entity. Similarly, the ECAP shall use Base Economy Sales for the billing period to compute Base Economy Sales Credits (separately for Daytime and Nighttime) and Base Economy Sales Cost, based on Economy Sales Price (separately for Daytime and Nighttime) and the Coal Energy rate, respectively, and shall then allocate such Base Economy Sales Credits and Base Economy Sales Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall then calculate Base Billing Energy Cost for the billing period, by adding Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchases and Power Sales Resource Energy Revenue, and shall allocate such

Base Billing Energy Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

Finally, the ECAP shall calculate for the billing period each Billing Unit Entity's (i) Base Energy Cost, which shall be the total of the Billing Unit Entity's Base Transfer Sales Credit, Base Transfer Energy Cost, Base Economy Sales Credit, Base Economy Sales Cost and Remaining Base Energy Cost, and (ii) Base Average Energy Rate, which shall be the quotient of the Billing Unit Entity's Base Energy Cost divided by its Base Billing Energy determined pursuant to the billing units assigned by the Billing Unit Program.

6.2 Formulating Base Adjustor Per Unit Cost.

The ECAP shall allocate to each Billing Unit Entity based on the Billing Unit Entity's Allocated Capacity Percentage the billing period's total Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Cost, which allocation ECAP shall add to the Billing Unit Entity's Base Energy Cost to formulate the Billing Unit Entity's Base Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Base Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Base Fuel Adjustor Cost divided by its Base Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.3 Formulating Base Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Base Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Base Adjustor Per Unit Cost less the sum of (i) its Base Power Cost Adjustor Base and (ii) its Base Power Cost Adjustor Rate, and (b) Base Over or Under Collection, which shall be the product of the Billing Unit Entity's Base Incremental Unit Cost multiplied by its Base Billing Energy. Each Billing Unit Entity's Base Over or Under Collection shall then be added to the balance in its Base Fuel Bank.

6.4 Formulating Total Other Energy Cost.

Each billing period, the ECAP shall use the Economy Purchase Rate (separately for Daytime and Nighttime) to determine S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit based on S&G And Supplemental Transfer. Such S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit shall then be allocated as appropriate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall allocate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program (i) the billing period's Other Economy Sales

Credit as appropriate based on the Billing Unit Entity's proportionate share of the billing period's Post-Transfer S&G And Supplemental Capacity and Other Billing Energy, and (ii) the billing period's Other Energy Cost based on the Billing Unit Entity's Other Billing Energy. The ECAP shall then assign to each Billing Unit Entity pursuant to the Billing Unit Entity's ACP and/or interest in and the billing units assigned by the Billing Unit Program, as applicable, the Billing Unit Entity's S&G PPA Energy Charge, Supplemental Energy Charge, Base Transfer Purchase Cost, Other Energy Cost, Directed Sales Credit, and its share of Base Mismatch Energy Credit, Base Mismatch Energy Cost, and Other Mismatch Energy Credit.

Finally, the ECAP shall determine for the billing period (i) each Billing Unit Entity's Total Other Energy Cost, which shall be equal to the sum of all the credits and costs allocated or assigned to the Billing Unit Entity as described in this Section 6.4, and (ii) each Billing Entity's Other Average Energy Rate, which shall be the quotient of its Total Other Energy Cost divided by its Total Other Billing Energy.

6.5 Formulating Other Adjustor Per Unit Cost.

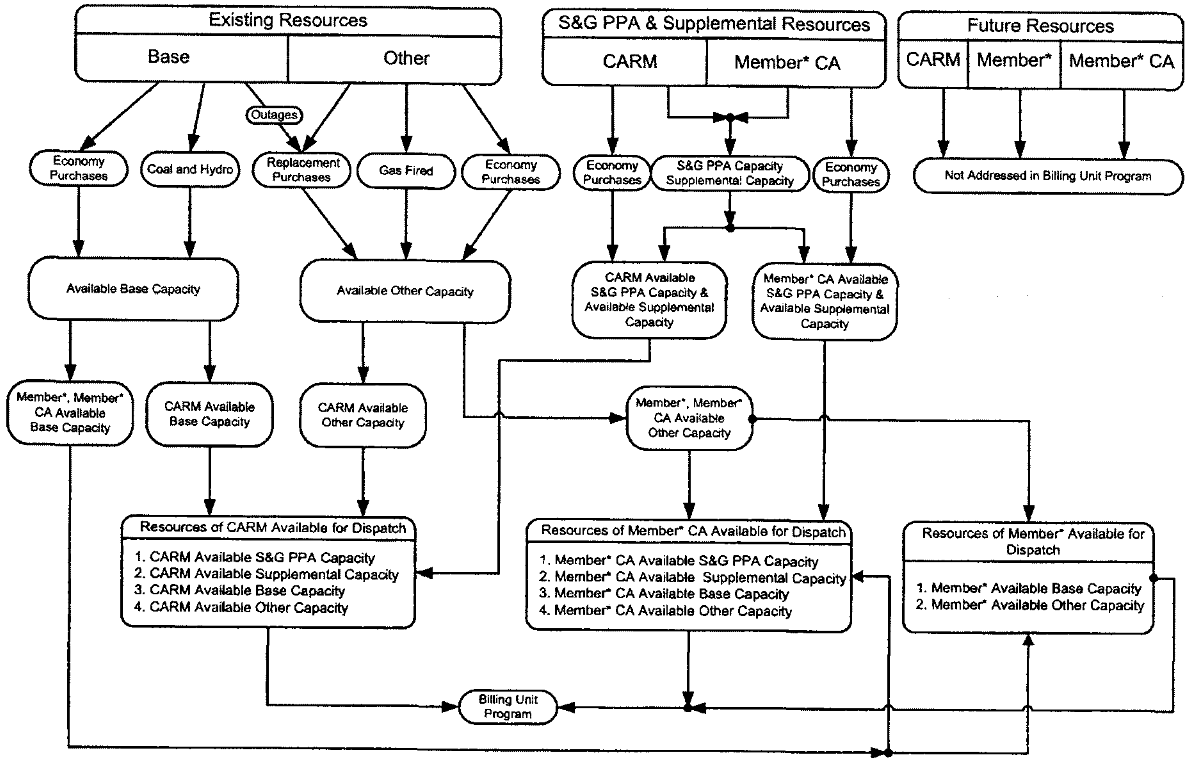
The ECAP shall allocate to each Billing Unit Entity the billing period's (i) total Other Transmission Wheeling Cost based on the Billing Unit Entity's Allocated Capacity Percentage, and (ii) S&G PPA Demand Charge, S&G PPA Wheeling Cost, Supplemental Demand Charge and Supplemental Wheeling Charge, pursuant to the Billing Unit Entity's ACP share or interest therein, if any. The ECAP shall then add such allocations to each Billing Unit Entity's Total Other Energy Cost to formulate the Billing Unit Entity's Other Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Other Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Other Fuel Adjustor Cost divided by its Total Other Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.6 Formulating Other Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Other Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Other Adjustor Per Unit Cost less the sum of (i) its Other Power Cost Adjustor Base, plus (ii) its Other Power Cost Adjustor Rate, and (b) Other Over or Under Collection, which shall be the product of the Billing Unit Entity's Other Incremental Unit Cost multiplied by its Other Billing Energy. Each Billing Unit Entity's Other Over or Under Collection shall then be added to the balance in its Other Fuel Bank.

Appendix A to Exhibit A-4 to Rate Schedule A: AEPCO Resources Definitions Flow Diagram



Appendix B Footnotes:

(1) Subroutine: CARM Post S&G And Supplemental Load is first assigned to CARM Minimum Other Capacity.
(1a) Subroutine: CARM Load is first assigned to CARM Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G and Supplemental Transfer Other Schedule or Post S&G And Supplemental Transfer Load.
(3) Subroutine: CARM Excess S&G And Supplemental Capacity is allocated as CARM S&G And Supplemental Transfers proportionately based on need to Member* Other Schedule and Member* CA Post Base Load, until such CARM Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule and Member* CA Post Base Load are satisfied.
(4) Subroutine: Member*, Member* CA Excess Base Capacity is allocated proportionately based on need to CARM and Member* CA Post-S&G And Supplemental TransferLoad and Member* Post-S&G And Supplmental Transfer Other Schedule until such Member*, Member* CA Excess Base Capacity is consumed, or until such CARM and Member* CA Post S&G and Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule are satisfied.
(5) Subroutine: CARM Excess Base Capacity is allocated proportionately based on need to Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G And Supplemental Transfer Load until such CARM Excess Base Capacity is consumed, or until Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G And Supplemental TransferLoad are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

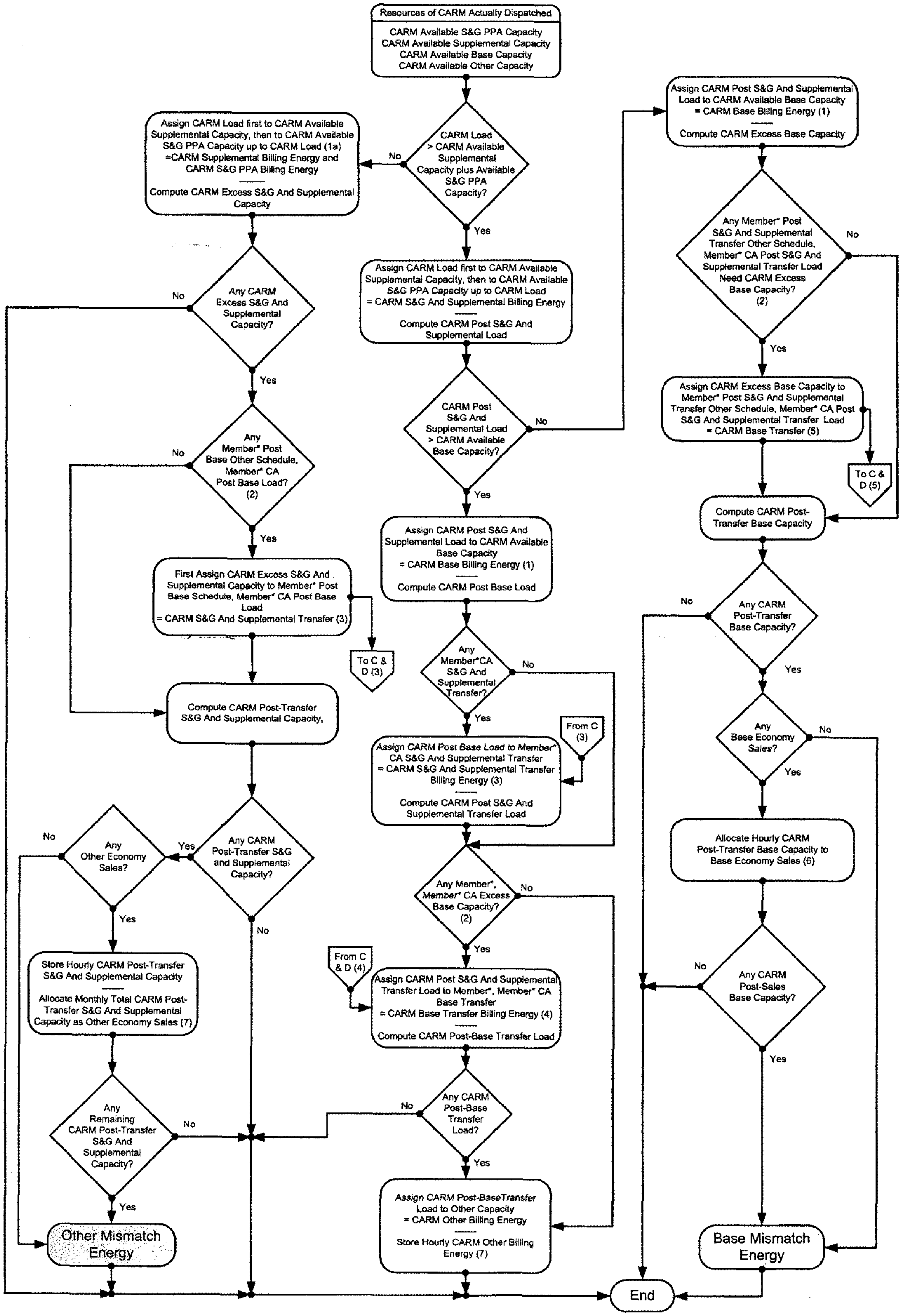
Appendix C Footnotes:

(1) Subroutine: Member* CA Post S&G And Supplemental Load is first assigned to Member* CA Minimum Other Capacity.
(1a) Subroutine: Member* CA Directed Sales and Load is first assigned to Member* CA Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA Excess S&G And Supplemental Capacity is allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* CA Excess Base Capacity is allocated proportionately based on need to Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

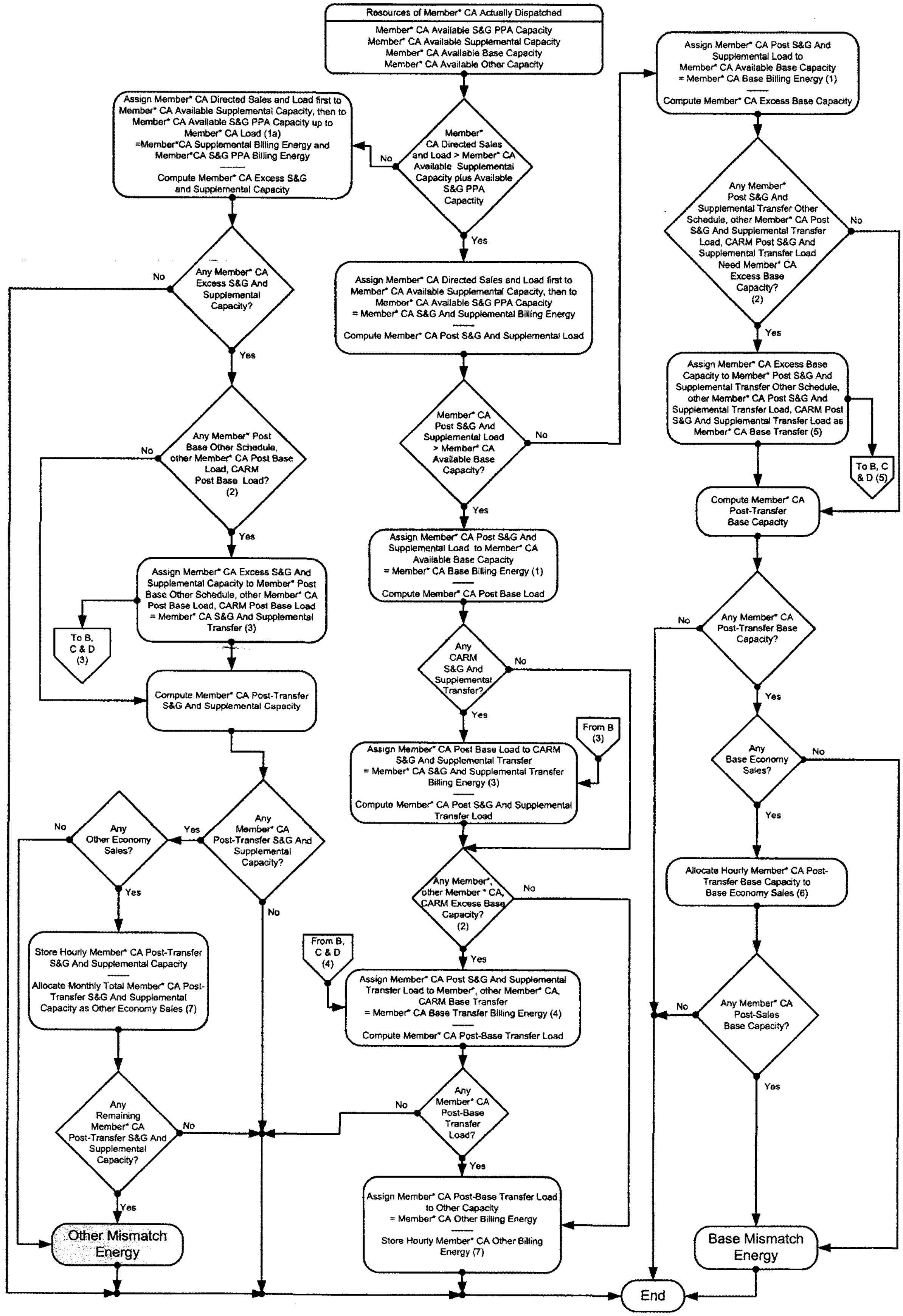
Appendix D Footnotes:

(1) Subroutine: Member* Base Schedule is first assigned to Member* Minimum Other Capacity.
(2) Subroutine: (2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA and CARM Excess S&G And Supplemental Capacity are allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Post Base Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* Excess Base Capacity is allocated proportionately based on need to each Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.
(8) No Partial Requirements Member with an interest in S&G PPA currently plans to operate outside the AEPCO pseudo-control area. In the event that a Partial Requirements Member with such an interest chooses to operate outside the AEPCO pseudo-control area in the future, the Appendix D flow chart for such a Member* will need to be modified.

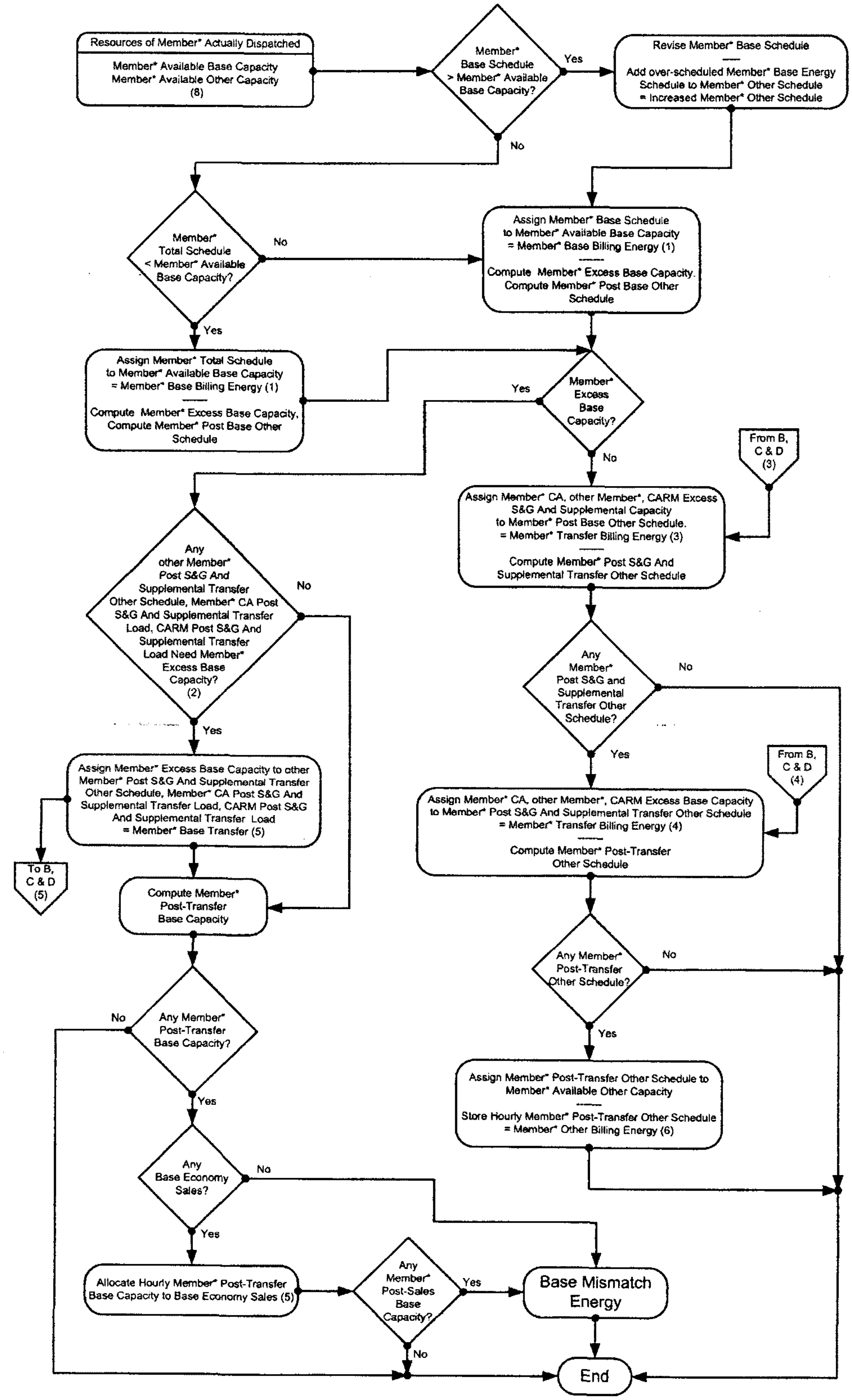
Appendix B to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
CARM Load Use of AEPCO Resources and Assignments as Additional and Base Transfers and AEPCO Third Party Sales



Appendix C to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* CA Load use of AEPCO Resources and Assignments as S&G PPA and Base Transfers and AEPCO Third Party Sales

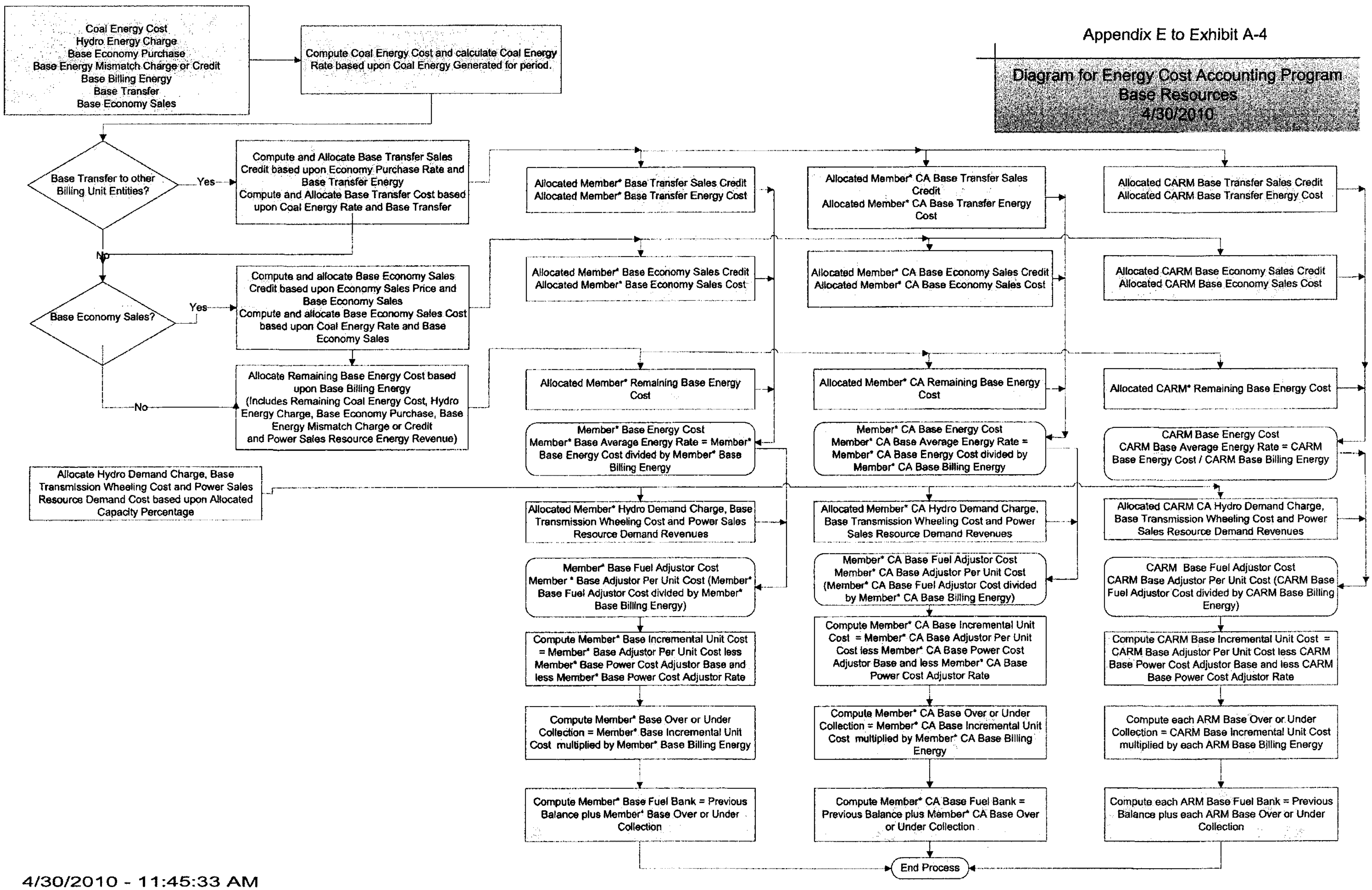


Appendix D to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* Use of AEPCO Resources and Assignments as Base Transfers and AEPCO Third Party Sales



Appendix E to Exhibit A-4

Diagram for Energy Cost Accounting Program
Base Resources
4/30/2010



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Appendix F to Exhibit A-4

Diagram for Energy Cost Accounting Program Other Resources 4/30/2010

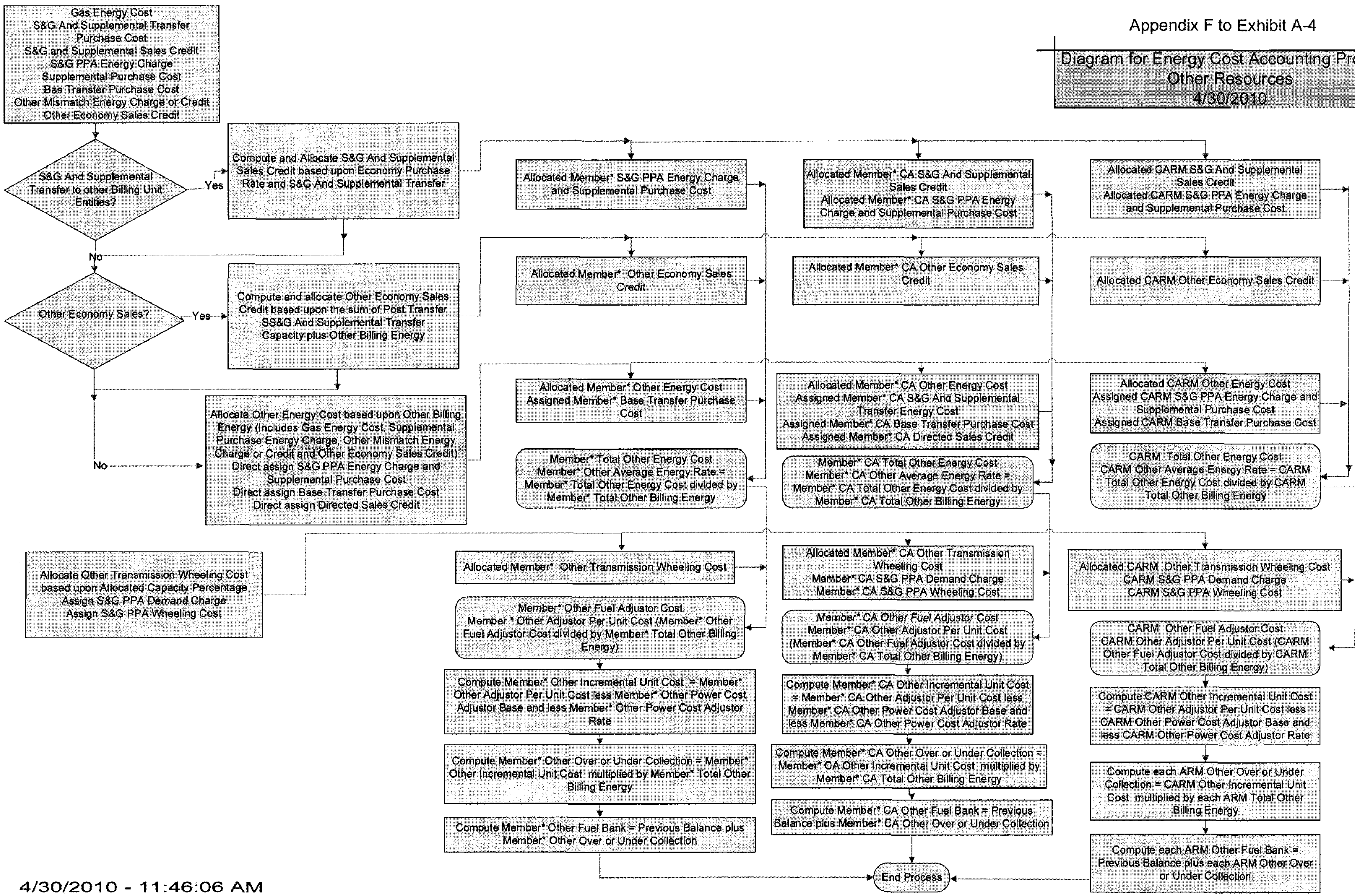

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Exhibit A-5 to Rate Schedule A
Allocated Capacity Percentages (ACP),
Allocated Capacity (AC)
and Reserves

ACP and AC DETERMINATION

An Allocated Capacity Percentage (ACP) was developed for Existing Resources as of the Effective Date for each Class A Member based on load forecasts from the 1996 Power Requirements Study (1996 PRS). The ACP in Existing Resources is used to calculate the Allocated Capacity (AC) for each Partial Requirements Member (PRM), and each All Requirements Member (ARM) in Existing Resources.

At the outset of AEPCO's restructuring, AEPCO, all AEPCO Class A Members, and RUS had approved the use of the 1996 PRS for planning purposes. AEPCO and its Class A Members agreed to the specific use of the 1996 PRS and forecast year 2000 as the basis for calculating the ACP in Existing Resources 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 in Existing Resources is summarized in Part A of Appendix A to this Exhibit A-5. The ACP calculation for Existing Resources utilized the forecasted year 2000 monthly coincident peaks of the Class A Members, which were obtained by multiplying: (a) each Member's forecasted monthly non-coincident peak as identified in the 1996 PRS, by (b) a historical three-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 an ARM in Existing Resources shall be used to determine its AC in Existing Resources in the event such ARM elects to become a Partial Requirements Member pursuant to the Conversion Agreement between the Class A Members and AEPCO dated August 1, 2001 (Conversion Agreement). The sum of the ACP's of the ARMs shall be the ACP of the Collective ARM (CARM) for purposes of Rate Schedule A to Existing Wholesale Power Contracts.

The monthly AC assigned to each PRM and the CARM from Existing Resources has been calculated by: (1) determining the capacity (in MW) of the generating units that comprise Existing Resources; (2) determining the Reserve percentage (described hereinafter) to be set aside from the generating units that comprise Existing Resources; (3) subtracting the Power Sales Resources as of the Closing Date of AEPCO's restructuring, including associated reserves and delivery losses attributable to such Power Sales: (4) further reducing the Existing Resource generating unit capacity for AEPCO generating unit reserves and delivery losses; (5) adding the monthly capacity from the Federal Hydro Power Agreements; and (6) multiplying such net capacity of Existing Resources by the ACP of each PRM and the CARM.

The AC in Existing Resources of each PRM and the CARM is further subdivided into Available Base Capacity and Available Other Capacity and shall be as shown on Appendix B to this Exhibit A-5. The Available Base Capacity of each PRM and the CARM shall be the respective

ACP shares of Base Resources after reduction for delivery losses. The Available Other Capacity shall be the respective ACP share of Other Resources after reduction for reserves and delivery losses.

For AEPCO Resources added and not included as Existing Resources (currently the S&G PPA Resource), each Class A Member participating in the added Resource accepts an ACP in that Resource pursuant to its agreement with AEPCO. That ACP shall be derived by a method determined by AEPCO based on adequacy of Resources to meet the forecasted loads of participating Class A Members under a method adopted by the AEPCO Board of Directors prior to AEPCO's commitment to the added Resource. Each participating Class A Member's AC in the Resource shall be the product of its ACP in the added Resource multiplied by the capacity of the Resource after reduction for delivery losses, and if required, reserves.

The ACP of the participating Class A Members as a PRM or as a part of CARM in an added Resource shall be set forth in a revision to Appendix A to this Exhibit A-5. The AC of such participating Class A Members as a PRM and as the CARM in an added Resource shall be set forth in a revision to Appendix B to this Exhibit A-5. Both the Appendices A and B as so revised shall be provided by AEPCO to all Class A Members at the time of the commitment by AEPCO to the added Resource. No such revision of Appendices A and B shall affect the ACP and AC of the non-participating Class A Members.

The ACP for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix A to this Exhibit A-5, and the AC for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix B to this Exhibit A-5. Neither the ACP nor the AC of the S&G PPA Resource shall be changed absent the agreement of TRICO and the participating ARMs that comprise the CARM.

RESERVE PERCENTAGE DETERMINATION:

In accordance with WECC reliability criteria, AEPCO is required to have in reserve access to generation sufficient to cover AEPCO's largest single generating unit hazard. AEPCO's largest single generating hazard consists of an outage of 188 MW of coal-fired steam generating unit capacity (which includes 13 MW of spinning reserve capacity), and after the first hour of such an outage includes an additional 29 MW, which 29 MW is subject to call from AEPCO by other members of the Southwest Reserve Sharing Group pursuant to the Southwest Reserve Sharing Group agreement, to which AEPCO is party. For the first hour of the outage, AEPCO currently relies on the generating support of other members of the Southwest Reserve Sharing Group to cover AEPCO's largest single generating unit outage.

Based on the above, AEPCO shall seek to reduce the MW of generation that would be required to be set aside for coverage of AEPCO's largest single generating unit by purchasing reserved transmission capacity from Southwest Transmission Cooperative, Inc., Mohave Electric Cooperative, Inc. and others as available, in that order of priority. AEPCO shall seek such transmission capacity in amounts necessary to realize AEPCO's reserve generating unit capacity percentage as 6.7% from 2011 through 2020, and 7.0% for the period from 2021 through 2035, which are the reserve capacity percentages as set forth in Appendix B to this Exhibit A-5. AEPCO and SWTC shall annually agree to a plan for AEPCO to follow to seek to obtain such transmission capacity, which shall be provided to the Class A Members for review. To the

extent AEPCO obtains transmission capacity in accordance with the established plan, the Class A Members agree that AEPCO shall include the costs of such transmission capacity in AEPCO's rates to such Class A Members.

In the event AEPCO is unsuccessful or less than fully successful in its attempts to timely purchase such reserved transmission capacity in advance of the start of any calendar year, AEPCO shall have the unilateral right to increase the reserve capacity percentage of Appendix B to this Exhibit A-5 for such calendar year. In such event, AEPCO shall provide, timely in advance of the start of such calendar year, a revised Appendix B to this Exhibit A for such calendar year that shows the effect of such increased reserve capacity percentage on the Available Base Capacity and Available Other Capacity of each PRM and the CARM. AEPCO and the Class A Members shall use such revised Available Base Capacity and Available Other Capacity for the purposes of Exhibit A-4 in the affected calendar year.

Appendix A to Exhibit A-5

Schedule of Allocated Capacity Percentages

A. The schedule and calculation of the Allocated Capacity Percentages (ACP) for AEPCO Existing Resources existing as of August 1, 2001 (consisting of Existing Resources as set forth in Appendix B to Exhibit A-5) is shown below:

Allocated Capacity Percentage

1996 PRS Coincident Peak Demand Forecast – MW

Col. Ln.	Year 2000	1 Anza	2 Duncan	3 Graham	4 Mohave	5 Sulphur	6 Trico	7 Total
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	ACP	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

B. The Allocated Capacity Percentages (ACP's) for the S&G PPA 1 Resource consisting of the South Point and Griffth PPAs is 0% for both MEC and SSVEC. For the remaining Class A Members and the CARM, the resulting ACP's for the S&G PPA Resource are as follows:

	Anza	DVEC	GCEC	CARM	TRICO	Total
Allocated Capacity %	0.1%	0.1%	3.0%	3.2%	96.8%	100%

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2011

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	15.0	15.0	15.0	15.0	15.0	15.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources			8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves	(4)	2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity			534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP		21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP		35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP		31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves	(5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves			11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members			36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	48.8	48.8	48.8	48.8	48.8	48.8	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	47.2	47.2	47.2	47.2	47.2	47.2	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total AC			109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total AC			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity	(8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity	(8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity	(8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base		100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total Available Capacity			109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total Available Capacity			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2012

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	5.0	5.0	5.0	5.0	5.0	5.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources			8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves (4)		2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity			534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP		21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP		35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP		31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves	(5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves			11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members			36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	58.6	58.6	58.6	58.6	58.6	58.6	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	1.9	1.9	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	56.7	56.7	56.7	56.7	56.7	56.7	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total AC			109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total AC			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity	(8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity	(8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity	(8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base		100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total Available Capacity			109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total Available Capacity			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9
									a					

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2013

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources													
Apache ST-2 Coal-fired		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 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA (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
Fed Hydro - Parker-Davis PPA (1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources		368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources		205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA (1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources		573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation													
2nd Hr Reserves Reqd for LSH Plus 29 MW (2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available		40.0	40.0	40.0	40.0	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	40.0	40.0
Less: SWTC Transmission Reserved		90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved		0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Less: Transmission Import Capacity (3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap) (3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW													
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
Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses (4)	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
Less Power Sales Reserves - MW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity													
Existing Resoucre Units after Pwr Sales		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves (4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity		543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity		561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses													
CARM Existing Resource @ ACP	11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP	21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP	35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP	31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)													
CARM Reserves		4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves		7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves (5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves		11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit (6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources		7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources													
Griffith Purchased Power		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power		0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Total S&G PPA Resources		0.0	0.0	0.0	0.0	70.0	70.0	70.0	70.0	70.0	70.0	0.0	0.0
Total After Network Losses		0.0	0.0	0.0	0.0	68.4	68.4	68.4	68.4	68.4	68.4	0.0	0.0
CARM Available S&G Capacity	3.2%	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0
TRICO Available S&G Capcity	96.8%	0.0	0.0	0.0	0.0	66.2	66.2	66.2	66.2	66.2	66.2	0.0	0.0
Member Total Allocated Capacity (MW)													
CARM Total AC		59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total AC		110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total AC		187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC		170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total		529.0	529.0	533.8	539.3	607.9	608.1	609.0	608.6	607.6	597.1	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)													
CARM Available Base Capacity (8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity (8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity (8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity (8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base	100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)													
CARM Available Other Capacity (8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity (8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity (8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity (8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap		168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)													
CARM Total Available Capacity		59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total Available Capacity		110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total Available Capacity		187.9	187.9	189.7	191.6	191.7	191.8	192.1	192.0	191.6	187.9	187.9	187.9
SSVEC Total Available Capacity		170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total		529.0	529.0	533.9	539.3	608.0	608.2	609.0	608.7	607.6	597.2	528.8	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2014

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources													
Apache ST-2 Coal-fired		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 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA (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
Fed Hydro - Parker-Davis PPA (1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources		368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources		205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA (1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources		573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation													
2nd Hr Reserves Reqd for LSH Plus 29 MW (2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available		40.0	40.0	40.0	40.0	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	40.0	40.0
Less: SWTC Transmission Reserved		90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved		0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Less: Transmission Import Capacity (3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap) (3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW													
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
Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses (4)	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
Less Power Sales Reserves - MW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity													
Existing Resoucre Units after Pwr Sales		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves (4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity		543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity		561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses													
CARM Existing Resource @ ACP	11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP	21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP	35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP	31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)													
CARM Reserves		4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves		7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves (5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves		11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit (6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources		7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources													
Griffith Purchased Power (7)		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power (7)		0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Total S&G PPA Resources		0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0
Total After Network Losses		0.0	0.0	0.0	0.0	78.2	78.2	78.2	78.2	78.2	78.2	0.0	0.0
CARM Available S&G Capacity	3.2%	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	0.0	0.0
TRICO Available S&G Capcity	96.8%	0.0	0.0	0.0	0.0	75.7	75.7	75.7	75.7	75.7	75.7	0.0	0.0
Member Total Allocated Capacity (MW)													
CARM Total AC		59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total AC		110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total AC		187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC		170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total		529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)													
CARM Available Base Capacity (8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity (8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity (8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity (8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base	100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)													
CARM Available Other Capacity (8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity (8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity (8)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity (8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap		168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)													
CARM Total Available Capacity		59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total Available Capacity		110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total Available Capacity		187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity		170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total		529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2015 thru 2020

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requirement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			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 S&G PPA Resources			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 After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(7)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(7)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(7)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(7)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity	(7)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2021 thru 2035

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources													
Apache ST-2 Coal-fired		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 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA (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
Fed Hydro - Parker-Davis PPA (1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources		368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Existing Resource Units		388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Subtotal Fed Hydro PPA (1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources		406.9	406.9	411.8	417.3	417.4	417.7	418.6	418.2	417.2	406.7	406.7	406.9
Reserve Caculation													
2nd Hr Reserves Reqd for LSH Plus 29 MW (2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available		40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Less: Western/MEC Transmission Reserved		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity (3)		190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Remaining Reserve Requrement (MW)		27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Reserve Requrement (% of Unit Cap) (3)		7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Power Sales Resources MW													
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
Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses (4)	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
Less Power Sales Reserves - MW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity													
Existing Resoucre Units after Pwr Sales		388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Less Member Losses after Reserves (4)	2.31%	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Net Existing Resource Unit Capacity		379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7
Existing Fed Hydro Capacity		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity		398.6	398.6	403.5	409.0	409.1	409.4	410.3	409.9	408.9	398.4	398.4	398.6
Portion of Member Capacity Net of Losses													
CARM Existing Resource @ ACP	11.4%	45.4	45.4	46.0	46.6	46.6	46.7	46.8	46.7	46.6	45.4	45.4	45.4
TRICO Existing Resource @ ACP	21.1%	84.1	84.1	85.1	86.3	86.3	86.4	86.6	86.5	86.3	84.1	84.1	84.1
MEC Existing Resource @ ACP	35.8%	142.7	142.7	144.4	146.4	146.4	146.6	146.9	146.7	146.4	142.6	142.6	142.7
SSVEC Existing Resource @ ACP	31.7%	126.4	126.3	127.9	129.6	129.7	129.8	130.1	129.9	129.6	126.3	126.3	126.3
Member Reserve Shares (MW)													
CARM Reserves		3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
TRICO Reserves		5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
MEC Reserves (5)		9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
SSVEC Reserves		8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Less: EuroFresh Reserve Credit (6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources		4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Total Reserves Req'd of Class A Members		27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
S&G PPA Resources													
Griffith Purchased Power		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power		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 S&G PPA Resources		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 After Network Losses		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity	3.2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity	96.8%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)													
CARM Total AC		42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total AC		78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total AC		133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total AC		121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total		375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5
Member Available Base Capacity After Power Sales, Losses (MW)													
CARM Available Base Capacity (7)	11.4%	41.1	41.1	41.7	42.3	42.3	42.4	42.5	42.4	42.3	41.1	41.1	41.1
TRICO Available Base Capacity (7)	21.1%	76.1	76.1	77.1	78.3	78.3	78.4	78.6	78.5	78.3	76.1	76.1	76.1
MEC Available Base Capacity (7)	35.8%	129.2	129.2	130.9	132.9	132.9	133.1	133.4	133.2	132.9	129.1	129.1	129.2
SSVEC Available Base Capacity (7)	31.7%	114.4	114.3	115.9	117.6	117.7	117.8	118.1	117.9	117.6	114.3	114.3	114.3
Subtotal Base	100.0%	360.8	360.7	365.6	371.1	371.2	371.7	372.6	372.0	371.1	360.6	360.6	360.7
Member Available Other Capacity After Losses, Reserves (MW)													
CARM Available Other Capacity (7)	11.4%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
TRICO Available Other Capacity (7)	21.1%	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
MEC Available Other Capacity (7)	35.8%	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
SSVEC Available Other Capacity (7)	31.7%	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Subtotal Available Other Cap		14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Member Total Available Capacity with Available S&G Capacity (MW)													
CARM Total Available Capacity		42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total Available Capacity		78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total Available Capacity		133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total Available Capacity		121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total		375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as *changes are implemented* to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

Exhibit A-6: Sample Bill

INVOICE

To: Member *
Address
City, AZ

'ATTN:

Member *		ACP %		
DATE:				February 10, 2011
January, 2011				
				Total $
Fixed Charge				
O&M Charge				
		kwh	$/kwh	Total $
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
Minimum Other Capacity Charge				
	DOAF			
Demand Overrun Adjustment	%			
Overrun Energy Charge				
	mkW	12MORA		
Power Factor Adjustor				
ACC Gross Operating Revenue Assessment				

Exhibit A-6: Sample Data for Bill	
Member * 1	Monthly
	MWH
Base Billing Energy	
Base Economy Purchases	
Off-peak	
On-Peak	
Base Transfer delivered	
Off-peak	
On-Peak	
Base Economy Sales credits	
Off-peak	
On-Peak	
Base Mismatch Energy	
Other Billing Energy	
Off-peak	
On-Peak	
Supplemental Transfer Billing Energy received	
Off-peak	
On-Peak	
S&G PPA Transfer Billing Energy received	
Off-peak	
On-Peak	
Base Transfer Billing Energy received	
Off-peak	
On-Peak	
Total Other Energy	
Off-peak	
On-Peak	
Other Mismatch Energy	
Other Ecomony Sales credits	

Exhibit A-6: Sample Bill

INVOICE

To: Member * CA
Address
City, AZ

'ATTN:

Member * CA		**ACP %**		
DATE:				**February 10, 2011**
January, 2011				
				Total $
Fixed Charge				
O&M Charge				
		kwh	**$/kwh**	**Total $**
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Supplemental Billing Energy				
Supplemental Billing Energy Fuel Adjustor				
S&G PPA Billing Energy				
S&G PPA Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
Minimum Other Capacity Charge				
	DOAF			
Demand Overrun Adjustment	**%**			
Overrun Energy Charge				
	mkW	**12MORA**		
Power Factor Adjustor				

ATTACHMENT 3 to Third Amendment to Partial Agreement

Schedule B

SCHEDULE B
TO PARTIAL REQUIREMENTS AGREEMENTS
Dated May 11, 2010
PRM RIGHTS, ABILITIES, AND CONSTRAINTS ASSOCIATED WITH ENERGY FROM AEPCO RESOURCES

1. INTRODUCTION

The primary purpose of this Schedule B is to define how a Partial Requirements Member (PRM) will access its entitlement to energy available from its AC in AEPCO Resources, such energy purchased pursuant to the Partial Requirements Capacity and Energy Agreement between Arizona Electric Power Cooperative, Inc. (AEPCO) and Member (Agreement) at the energy rates set forth in Exhibit A-1 to Rate Schedule A. This Schedule B defines available AEPCO Resources and the minimum capacity requirements for such resources, and how a PRM will schedule energy from AEPCO Resources in a manner consistent with such minimums and the Cost Causation principles upon which the energy rates are determined pursuant to Exhibit A-4 to Rate Schedule A.

Also recognized in this Schedule B is that the energy available for sale to a PRM at the energy rates set forth in Rate Schedule A can from time to time be a function of operating characteristics and limitations associated with the AEPCO Resources.

In addition, this Schedule B specifies the methodology pursuant to which additional charges shall be made by AEPCO to a PRM in the event that: (1) a PRM requires energy from AEPCO Resources that is in excess of the energy available to the PRM associated with its AC in AEPCO Resources; or (2) a PRM does not take its required minimum capacity and energy from AEPCO Resources because the PRM has used energy from other sources that displaces the use of such minimum energy from AEPCO Resources. Such additional charges shall be billed to the PRM pursuant to Rate Schedule A.

2. 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" shall mean Allocated Capacity.

"AEPCO Federal Hydro Power Capacity" shall mean that amount of capacity on an hourly basis scheduled by AEPCO pursuant to Federal Hydro Power Agreements.

"AEPCO Minimum Base Capacity" shall mean the capacity from Available Base Capacity that must be operated from time to time to maintain system reliability or for other reasons, reflecting AEPCO's determination as to the schedule of energy from the Federal Hydro Power Agreements and AEPCO Minimum Coal Capacity.

"AEPCO Minimum Coal Capacity" shall mean the minimum output for safe and reliable operation of Apache Units 2 and 3.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Scheduling Portal" shall mean an internet web site maintained by AEPCO and accessible by all Class A Members for the purpose of AEPCO posting ongoing information relating to the availability and minimum must run requirements for AEPCO Resources.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in its Partial Requirements Capacity and Energy Agreement. The AC for each month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of that agreement.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sale Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to the Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with this Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"CARM" or "Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources and in S&G PPA, as applicable to each All Requirements Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A to the ARM Wholesale Power Contracts.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's By-laws.

"Cost Causation" shall mean the identification of all direct and indirect costs, revenue and billing units associated with individual Resources and services, such that costs, revenue and billing units can be accounted for and billed separately to the specific Class A Members participating in such Resource or receiving such service.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AEPCO Resources.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth and designated as Existing Resources in Appendix B to Exhibit A-5 to Rate Schedule A, consisting of Base Resource(s) and Other Resource(s).

"Federal Hydro Power Agreement(s)" shall mean 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 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).

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Intra-Day Schedule" shall mean a Real-Time Schedule.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with this Schedule B.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Power Sales Resource" shall mean a sale of capacity and energy from Existing Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"Pre-Schedule Day" shall mean the day on which a Pre-Schedule must be submitted for the next Scheduling Day.

"PRM" shall mean a Partial Requirements Member.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Schedule" shall mean for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"Schedule" shall mean, for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduled Day" shall mean the Scheduling Day, as defined by WECC, for which a Pre-Schedule has been submitted.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made by AEPCO for a period of less than a year to serve load of CARM or a Member* CA as a Planning Contract Member in excess of CARM's or such Planning Contract Member's ACP shares of capacities of S&G PPA and Existing Resources.

"Tag" shall mean the collection of information in the electronic form of request and subsequent response as part of the process implemented by the North American Electric Reliability Corporation for electronically communicating a request for, securing approval of, and recording an energy transaction via the Internet.

3. AEPCO RESOURCE AVAILABILITY

3.1 Available Base Capacity.

AEPCO shall continuously notify each Scheduling Agent of Available Base Capacity by posting such information to the AEPCO Scheduling Portal. On a day-ahead and hourly basis, AEPCO will post Available Base Capacity reflecting AEPCO's determination as to the schedule of the hydropower plus available coal capacity. A Member* shall create its Base Schedules using its ACP share of Available Base Capacity as posted to the AEPCO Scheduling Portal.

3.2 Available Other Capacity.

A Member* shall create its Other Schedule of energy from its ACP share of Available Other Capacity, which may be an amount up to the difference obtained by subtracting the Member*'s ACP share of Available Base Capacity for each hour from such Member*'s AC in AEPCO Resources.

3.2.1 Once a Member* has submitted a Pre-Schedule of its Other Schedule, the Member* may not decrease such Other Schedule on an intraday basis (*i.e.* during the Scheduled Day for which the Other Schedule applies); provided, however, that in the event that a Member* experiences an unforeseen downward deviation in Native Load as compared to what was reasonably forecasted in its Pre-Schedule, such Member* shall first decrease to the extent possible its schedule from Member* Resources, and then may decrease its Other Schedule by means of an Intraday Schedule.

3.2.2 In the event that a Member* decreases an Other Schedule by means of an Intraday Schedule, the Member* shall provide to AEPCO by noon of the second subsequent Business Day evidence showing that Member*'s Native Load was, in fact, less than was reasonably forecasted in the Other Schedule. If AEPCO rejects such evidence, the Member* shall be billed

as if such Other Schedule were not decreased, and the Member* shall pay the amount billed, and may dispute its payment pursuant to the Dispute Resolution provisions of its Agreement.

3.3 Available S&G PPA Capacity.

On a day-to-day basis, AEPCO will post to the AEPCO Scheduling Portal the available capacity and the hours of each day in which AEPCO is obligated to take such capacity if scheduled, for each of the purchase power agreements which make up Available S&G PPA Capacity. A Member* shall create its S&G PPA Schedule using 100% of its ACP share of available capacity from either or both purchase power agreements of Available S&G PPA Capacity, for all the hours of the scheduling day for which AEPCO is obligated to schedule capacity from each such purchase power agreement.

3.5 Obligations of the Parties for the Period Beyond January 1, 2021.

Beginning January 1, 2021, a PRM's AC shall be reduced to reflect the effective retirement of certain Other Resources. To the extent that such retirement reduces Available Other Capacity such that a PRM's Available Other Capacity is available only as reserve capacity, the provisions of Sections 3.2. and 4.2 shall no longer be of any force or effect. In addition, a PRM's Available Base Capacity may be reduced in the event AEPCO must use Available Base Capacity to meet operating reserve requirements, unless the PRM and AEPCO agree that operating reserves may be supplied from another source.

4. MINIMUM CAPACITY REQUIREMENTS:

4.1 Minimum Base Capacity Requirements.

On a day-to-day basis, AEPCO will post to the AEPCO Scheduling Portal Minimum Base Capacity reflecting AEPCO's discretion as to the schedule of energy from the Federal Hydro Power Agreements and Minimum Coal Capacity. A Member* shall schedule and a Member* CA shall take energy available from its AC in AEPCO Resources in an hour in an amount no less than its share of AEPCO Minimum Base Capacity. A Billing Unit Entity's share of AEPCO Minimum Base Capacity shall be the product of its ACP multiplied by AEPCO Minimum Base Capacity for that hour. If a Billing Unit Entity fails to takes its Minimum Base Capacity, AEPCO shall charge a Minimum Base Capacity Charge, as applicable, either pursuant to Section 6.2.1 of this Schedule B for a PRM or pursuant to Section 2.4 of its Rate Schedule A for an ARM.

4.2 Minimum Other Capacity Requirements.

From time to time, AEPCO may be required to generate out of merit order energy from Other Resources for such reasons as: to respond to transmission constraints, to maintain reliability in certain peak periods of the year, to support generation needs in the event of an outage of a Base Resource, or to consume scheduled

natural gas deliveries in the event natural gas storage cannot be utilized. As Minimum Other Capacity is determined, AEPCO will post to the AEPCO Scheduling Portal the nature, amount, and deration of Minimum Other Capacity as in effect from hour to hour. A Member* must schedule and a Member* CA must take energy available from its Available Other Capacity in an hour in an amount no less than its share of Minimum Other Capacity. For each hour of each month, a Billing Unit Entity's share of AEPCO Minimum Other Capacity shall be the product of its ACP multiplied by AEPCO Minimum Other Capacity. If a Billing Unit Entity fails to takes its Minimum Other Capacity, AEPCO shall charge a Minimum Other Capacity Charge, as applicable, either pursuant to Section 6.2.1 of this Schedule B for a PRM or pursuant to Section 2.4 of its Rate Schedule A for an ARM.

4.3 Minimum S&G PPA Capacity.

AEPCO will dispatch, account for, and bill the costs of Available S&G PPA Capacity in accordance with one or more applicable agreements between AEPCO and all Class A Members with an ACP in S&G PPA. Schedules submitted by Members to AEPCO for the use of Available S&G PPA Capacity will comport with the actual dispatch limitations and requirements of the S&G PPA.

In each hour, a Billing Unit Entity shall be responsible for taking and paying for its ACP share, if any, of energy from S&G PPA Capacity as dispatched by AEPCO.

5. SCHEDULING:

5.1 General Scheduling Concepts.

This section establishes a framework for scheduling AEPCO Resources consistent with cost causation principles. A Member* shall submit separate Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, to AEPCO. Schedules submitted by Member*s shall not dictate physical dispatch, except in the case of the S&G PPA. AEPCO shall retain full generation control, develop forecasts of resource requirements, and dispatch the resources at its disposal using traditional economic stacking principles.

5.2 Scheduling Agent.

A Member* shall designate itself or a third party as Scheduling Agent to compute and provide to AEPCO Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, for use of energy from its AC in AEPCO Resources. The Member* shall bind its Scheduling Agent to abide by the confidentiality provisions of this Agreement in order to prohibit sharing of AEPCO Resource costs and availability information with others.

5.3 Member* Schedules.

The Scheduling Agent shall develop Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, pursuant to this Section 5 and Exhibit B-1 hereof. Scheduling Agent shall submit such Schedules to AEPCO in accordance with the timetables outlined in Exhibit B-1 hereof.

5.4 Scheduling Limitations.

Schedules may be limited in accordance with the following.

5.4.1 Scheduling Limits during Base Resource Outage or Reduction.

AEPCO will notify the Scheduling Agents as soon as practicable after the outage or reduction of a Base Resource.

For so long as AEPCO is a member of the Southwest Reserve Sharing Group or its successor (SRSG), the following time frames shall apply for scheduling in response to an outage or reduction of a Base Resource:

(a) Initial Sixty (60) Minute Period - The replacement energy for the first sixty (60) minutes following notification of the loss to the SRSG parties will be provided to AEPCO pursuant to the SRSG Agreement, and Schedules need not be adjusted for such initial sixty (60) minutes.

(b) After the Initial Sixty (60) Minute Period - The Scheduling Agent shall reduce the Member*'s Base Schedule by the Member*'s share of the lost capacity beginning at sixty (60) minutes following AEPCO's notification of the outage to the SRSG parties. In such event, the Scheduling Agent may increase its Other Schedule to replace the lost capacity; otherwise, such capacity will be replaced by AEPCO. Within ten (10) minutes of notification of a Base Resource outage or reduction, Scheduling Agent must notify AEPCO if Member* does not want to increase its Other Schedule after such sixty (60) minute period to replace the lost capacity; unless AEPCO receives such notice within such ten (10) minutes, AEPCO will replace the lost capacity. Any otherwise applicable requirements of Exhibit B-1 that set timeframes for notice will not apply in such event.

If the SRSG Agreement is terminated or AEPCO is otherwise no longer a member of SRSG, the Parties agree to diligently work to determine how the capacity will be replaced in case a Base Resource experiences an outage or reduction.

5.4.2 Scheduling Limits during Other Resource Outage.

In the event an outage or de-ration of an Other Resource occurs, AEPCO shall post notice of such event to the AEPCO Scheduling Portal and replace the reduced capacity of the Other Resource, and Scheduling Agent may but shall not be required to alter Member*'s Other Schedule. Within ten (10) minutes of notification of an Other Resource outage or reduction, Scheduling Agent must notify AEPCO if Member* plans to alter its Other Schedule; unless AEPCO receives such notice within such ten (10) minutes, AEPCO will replace the lost capacity. Any otherwise applicable requirements of Exhibit B-1 that set timeframes for notice will not apply in such event.

5.4.3 Overscheduling.

5.4.3.1 If a Scheduling Agent submits a Base Schedule in an amount that exceeds the Member*'s Available Base Capacity, the amount in excess of Member*'s Available Base Capacity will become part of the Member*'s Other Schedule for the purposes of the energy accounting of the Billing Unit Program of Exhibit A-4.

5.4.3.2 If a Scheduling Agent submits Schedules that collectively exceed the Member*'s AC for an hour, AEPCO is not obligated to provide the amount above AC, provided, however, that if AEPCO does not seek to have Member* correct such Schedules, Member* shall be subject to a penalty, calculated in accordance with Section 6.2.2.

5.5 AEPCO Scheduling Responsibilities.

5.5.1 AEPCO shall communicate by posting to the AEPCO Scheduling Portal all information required in accordance with this Section 5.5 and Exhibit B-1 hereof. Using the AEPCO Scheduling Portal, AEPCO shall publish and update Available Base Capacity, Available Other Capacity, and Available S&G PPA Capacity, all on a real time basis. In addition, AEPCO will contact and notify Scheduling Agents as soon as practicable when units become unavailable and/or are derated, and when units return to service, in whole or in part.

5.5.2 AEPCO shall be responsible for scheduling and dispatching AEPCO Resources on an economic basis to meet CARM load requirements, Member* CA load requirements, and Member* Schedules.

5.5.3 AEPCO shall make Replacement Purchases as necessary to meet load requirements and Schedules due to outages of AEPCO Resources.

5.6 Unit Limitations.

AEPCO shall maintain Resource Operation and Unit Dispatch Practices, attached hereto as Exhibit B-2 and made a part hereof, that among other things establish

limitations on the dispatching of AEPCO Resources and consequently provide a basis for AEPCO to make Other Economy Purchases and Replacement Purchases.

6. ADDITIONAL CHARGES:

6.1 Ordinary Service.

Unless otherwise provided in this Schedule B, the energy sold by AEPCO to a PRM pursuant to the Agreement shall be at the rates and charges set forth in Exhibit A-1 to Rate Schedule A to their respective Agreements.

6.2 Additional Charges.

In addition to the rates and charges set forth in Exhibit A-1 to Rate Schedule A, a PRM shall pay AEPCO the following additional amounts resulting from this Schedule B.

6.2.1 Capacity and Energy Below AC.

If a PRM is utilizing a Member* Resource, Future Resource, S&G PPA, or Supplemental Purchase in any hour to serve Native Load and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of AEPCO Minimum Base Capacity or Minimum Other Capacity, it shall pay a charge as set forth in this Section 6.2.1.

6.2.1.1 PRM Minimum Base Capacity Charge - In the event that a PRM has replaced its use of AEPCO Resources with a Member Resource, Future Resource, S&G PPA or Supplemental Purchase to serve Native Load in any hour and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of Minimum Base Capacity, AEPCO shall charge and the PRM shall pay a charge in an amount obtained by multiplying the lesser of (i) the amount of Member Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour, or (ii) the amount of the PRM's pro rata share of all PRMs' collective deficiency in their combined shares of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 to Rate Schedule A and as determined for the billing period. Member shall only be subject to PRM Minimum Base Capacity Charge to the extent that Available Base Capacity dispatched for Class A Members as a whole is below Minimum Base Capacity.

6.2.1.2 PRM Minimum Other Capacity Charge - In the event that a PRM has replaced its use of AEPCO Resources with a Member Resource, Future Resource, S&G PPA or Supplemental Purchase to serve Native Load in any hour and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of AEPCO Minimum Other Capacity, AEPCO shall charge and the

PRM shall pay an amount obtained by multiplying the lesser of (i) the amount of Member Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour, or (ii) the amount of the PRM's pro rata share of all PRMs' collective deficiency in their combined share of Minimum Other Capacity in such hour, by the Gas Energy Rate as defined in Exhibit A-4 to Rate Schedule A and as determined for the billing period.

6.2.1.3 In the event that in any hour both Sections 6.2.1.1 and 6.1.1.2 would apply, the PRM Minimum Other Capacity Charge will be determined first as set forth in Section 6.2.1.2 above, and the associated PRM Minimum Base Capacity Charge shall be an amount obtained by multiplying the lesser of (i) the amount of Member* Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour less the amount of energy used as the basis for the PRM Minimum Other Capacity Charge, or (ii) the amount of the PRM's deficiency in its share of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period.

6.2.2 Capacity and Energy Above AC.

In each month in which a Class A Member's use of AEPCO Resources exceeds its AC, AEPCO shall charge the Class A Member an amount equal to the Demand Overrun Adjustment as calculated in Section 2.3 of Rate Schedule A, and the Class A Member shall also pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Energy Rate.

7. REVISIONS TO EXHIBITS:

From time to time events will occur which will necessitate the revision of the Exhibits attached to this Schedule B. Except when such Exhibits specifically provide for updates by specific parties, such revisions shall only be made pursuant to mutual agreement of AEPCO and all PRMs.

EXHIBIT B-1

Merchant Scheduling Practices and Procedures

1. FOR MEMBERS* OUTSIDE THE AEPCO PSEUDO BALANCING AREA:

1.1 Introduction.

1.1.1 Prior to each Scheduled Day, the Scheduling Agent will provide Pre-Schedules identifying anticipated Base Schedules and Other Schedules for the Scheduling Day, as defined by WECC, by hour, to AEPCO. AEPCO may commit to natural gas purchases when Other Resources have been Pre-Scheduled.

1.1.2 On the Scheduled Day, the Scheduling Agent may submit Real-Time Schedules adjusting Base Schedules within the ramping and other operating limitations of the Base Resources located at the Apache Generating Station. Real-Time Schedules may be submitted to adjust Other Schedules in accordance with Section 3.2.1 and within the ramping and other operating limitations of the Other Resources located at the Apache Generating Station; such Real-Time Schedules adjusting Other Schedules will only be accommodated to the extent they can be coordinated with fuel scheduling adjustments. (See the operating day gas unit limitations outlined in the PRM load control transfer agreements.) All Real-Time Schedules must be submitted no later than seventy (70) minutes prior to the hour power is to flow.

1.1.3 AEPCO may be able to make exceptions and accommodate Real-Time Schedules that would require AEPCO to ramp at a faster rate than under normal operating levels when such adjustments are needed to deal with emergency situations; such requests will be dealt with case-by-case.

1.2 Pre-Schedules.

1.2.1 Scheduling Agent shall submit Member*'s preliminary estimated Pre-Schedules to AEPCO pre-schedulers by 1600 MST of the day prior to Scheduling Day as defined by WECC. The Pre-Schedules shall separately identify Base Schedules and Other Schedules. Preliminary Pre-Schedules may be submitted by phone, fax or e-mail.

1.2.2 Scheduling Agent shall submit Member*'s final Pre-Schedules to AEPCO pre-schedulers by 0630 MST of the Pre-Schedule Day. The Pre-Schedules shall separately identify Base Schedules and Other Schedules. Final Pre-Schedules may be submitted by phone, fax or e-mail.

1.2.3 Scheduling Agent is responsible for generating tags in accordance with WECC time-lines and procedures. AEPCO, as mutually agreed, may generate tags on behalf of the Scheduling Agent.

1.3 Day of Scheduling.

1.3.1 Real-Time Schedules must be provided to AEPCO at least seventy (70) minutes prior to the hour the Schedule is to flow.

1.3.2 Scheduling Agent is responsible for creating or modifying tags in accordance with WECC time-lines and procedures. AEPCO, as mutually agreed, may create tags on behalf of the Scheduling Agent.

1.3.3 In the event AEPCO chooses to modify the source of a Base Schedule or Other Schedule from its originally tagged source, AEPCO will be responsible for creating the tags associated with the modified source such Schedule. Upon notice from AEPCO no later than forty (40) minutes in advance of the hour, Scheduling Agent shall adjust any of the original tags to accommodate the new tag created by AEPCO, per AEPCO's direction.

1.4 Information Supplied by AEPCO Real Time.

1.4.1 Planned generating unit maintenance schedules.
1.4.2 Planned and unplanned full or partial generating unit outages.
1.4.3 AEPCO Minimum Base Capacity and AEPCO Minimum Other Capacity.

1.5 Emergency scheduling.

1.5.1 Schedules which do not meet the requirements in this Section 1 may be accepted by AEPCO subject to the agreement of all affected parties in the transaction.

1.6 Procedure for Rounding Tenths of MW to Whole MWs.

Initially, AEPCO will report hourly values for AC and for shares of Available Base Capacity, of AEPCO Minimum Base Capacity and of Minimum Other Capacity in tenths of a MW. To facilitate the industry standard of the scheduling of energy in whole MWs, values of hourly AC and shares of Available Base Capacity, of AEPCO Minimum Base Capacity and of Minimum Other Capacity in tenths of a MW shall be rounded down to whole MWs. Values for the hourly share of Available Other Capacity shall then be obtained by subtracting such rounded down share of Available Base Capacity from such rounded down AC for the same hour.

1.7 Intra Day Schedule Change Requiring Gas Generation.

1.7.1 As of early 2010, gas turbine minimum loading, run times and start-up cost is as follows. Applicable updates to this information shall be provided from time to time by AEPCO to Scheduling Agents.

1.7.1.1 Combine Cycle (82 MW): Minimum run time is monthly with a minimum loading of 20 MW every hour. Start-up is $4,469

1.7.1.2 Steam Unit #1 (72 MW): Minimum run time is monthly with a minimum loading of 20 MW every hour. Start-up is $4,469

1.7.1.3 Gas Turbine #1 (10 MW): Minimum run time is four (4) hours with a minimum loading of 2 MW every hour. Start-up is $1,817

1.7.1.4 Gas Turbine #2 (20 MW): Minimum run time is four (4) hours with a minimum loading of 2 MW every hour. Start-up is $1,646

1.7.1.5 Gas Turbine #3 (65 MW): Minimum run time is six (6) hours with a minimum loading of 5 MW every hour. Start-up is $1,514

1.7.1.6 Gas Turbine #4 (38 MW): Minimum run time is two (2) hours with a minimum loading of 10 MW every hour. Start-up is $ (to be provided by AEPCO)

1.7.2 El Paso Gas Scheduling Times.

1.7.2.1 Introduction.

The following closing times for each gas scheduling cycle are provided to assist Scheduling Agent when submitting Other Schedules. AEPCO requires at least a one (1) hour notice prior to such closing times in order to purchase gas from suppliers and to schedule the gas by means of El Paso's software. If there is any change to applicable closing times, AEPCO shall provide Scheduling Agents updates of such times.

1.7.2.2 Winter (Nov-Mar).
Pre-Schedule Day
Cycle 1: 0730 MST
Cycle 2: 1530 MST

Day of Flow
Cycle 3: 0930 MST
Cycle 4: 1300 MST

1.7.2.3 Summer (Apr-Oct).
Pre-Schedule Day
Cycle 1: 0630 MST
Cycle 2: 1430 MST

Day of Flow
Cycle 3: 0830 MST
Cycle 4: 1200 MST

1.8 After-the-Fact Check-Outs.

1.8.1 Mid-month - AEPCO and Scheduling Agent shall perform a mid-month check-out approximately on the 15th of each month. Check-out should include Base Schedules and Other Schedules.

1.8.2 Monthly - AEPCO and Scheduling Agent shall perform a month end check-out of schedule flow as soon as possible after the end of each month, but no later than four (4) working days after end of the month.

1.9 AEPCO Contacts.

The following contact information may be updated by AEPCO or a PRM, as applicable, at any time by providing notice to all contacts listed at the time for all other entities.

1.9.1 AEPCO Pre-Schedule Contacts

i Ron Goodman
(520) 586-5276
(520) 586-5445 Facsimile
rgoodman@aepco.coop

ii. Daniel Unrast
(520) 586-5528
(520) 586-5445 Facsimile
dunrast@aepco.coop

E-mails relating to Pre-Schedules shall be sent to all persons listed above.

1.9.2 AEPCO Real-Time Schedule Contacts

i Traders
(520) 586-5407
(520) 586-5445 fax
traders@aepco.coop

1.10 <u>PRM Scheduling Agent Contacts</u>.

1.10.1 PRM Scheduling Agent Pre-Schedule Contacts

i Penny Casey
(602) 605-2585
(602) 605-2831 facsimile
<u>Casey@wapa.gov</u>

i Tim Alme
(602) 605-2854
(602) 605-2831 facsimile

1.10.2 PRM Scheduling Agent Real-time Schedule Contacts

i On-Call Scheduler
(602) 605-2666
(602) 605-2831 fax

1.11 <u>Contacts for After-the Fact Check-Outs</u>.

1.11.1 AEPCO

i Ron Goodman
(520) 586-5276
(520) 586-5445 Facsimile
<u>rgoodman@aepco.coop</u>

ii. Daniel Unrast
(520) 586-5228
(520) 586-5445
<u>dunrast@aepco.coop</u>

1.11.2 PRM Scheduling Agent Contacts for After-the-Fact Check-Outs

i ??????????
(602) 605-2675
(602) 605-2490 facsimile

ii John Paulsen
(602) 605-2557
(602) 605-2831 facsimile

2. <u>FOR MEMBER* CAS INSIDE THE AEPCO PSEUDO BALANCING AREA</u>:

A Member* CA shall execute a Scheduling, Accounting and Reporting Services Agreement with AEPCO, which agreement shall identify any applicable scheduling practices or procedures, including procedures by which Member* CA can direct AEPCO to sell for Member* CA's benefit a specified amount of the energy to which Member* CA is entitled.

EXHIBIT B-2

AEPCO's Resource Operation & Unit Dispatch Practices

1. INTRODUCTION:

These Resource Operation & Dispatch Guidelines set forth the practices that AEPCO shall follow in: (a) operating AEPCO Resources, including the AC of the Partial Requirements Members and sales from AEPCO Resources, when: (i) Pre-Scheduling such Resources for dispatch by AEPCO on a least cost basis; (ii) placing such Resources out of service for planned or forced maintenance; (iii) making Third Party Economy Sales from such Resources and making Non-Base Economy Purchases against such Resources; (iv) purchasing for sale; (v) making power sales from such Resources; (vi) accounting for energy uses and costs; (vii) billing and collecting from third parties for capacity and/or energy sales, purchases, transmission and other services; and (viii) complying with regulatory requirements of Governmental Authorities having jurisdiction, all in accordance with the provisions of this Agreement.

2. AEPCO RESOURCE PRE-SCHEDULE PRACTICES:

AEPCO shall perform Resource pre-scheduling as follows:

2.1. Establishing Pre-schedules - AEPCO shall develop Resource Pre-Schedules in advance for each hour of the subsequent operating day(s) through midnight of the next working day in accordance with principles of least-cost dispatch of AEPCO Resources to the extent practicable. AEPCO shall submit such Pre-Schedules to TRANSCO for its implementation as required by TRANSCO. Pre-schedules shall specify sufficient Resources to serve forecast hourly AEPCO Delivered Load plus the Pre-Scheduled Energy requirements for delivery losses related to AEPCO Delivered Load. Pre-Schedules shall additionally provide AEPCO Resources on-line and operating in an unloaded state sufficient to provide Operating Reserves - Spinning Reserves and for Regulation and Frequency Response Service, both as required for AEPCO Delivered Load. Pre-Schedules shall additionally consider AEPCO provisions for unloaded and off-line generating capacity and/or interruptible load sufficient to provide for Operating Reserve - Supplemental as required for AEPCO Delivered Load. All AEPCO Resources shall be Pre-Scheduled to dispatch resources of lowest operating cost first. AEPCO shall coordinate with and provide Pre-Schedule information to all suppliers and transmitters of the AEPCO Resources involved in the Pre-Schedule. All Pre-Schedules shall be prepared with consideration for the following parameters:

2.1.1. Generator operating constraints such as minimum and maximum loading levels, ramp rates, minimum run times, maximum run times, system stability requirements (e.g., voltage support or VAR support), operating reserve requirements, planned outages, environmental compliance and any other constraint or condition affecting generation;

2.1.2. Generating unit testing requirements in accordance with Prudent Utility Practice;

2.1.3. Firm purchase contract conditions such as minimum and maximum load factors, minimum or maximum Energy take requirements, and any other constraint or condition affecting the ability to receive Capacity or Energy under the contract;

2.1.4. Generating unit outages which would limit a supplier's ability to deliver Capacity or Energy pursuant to a purchase contract;

2.1.5. The availability of Non-Base Economy Purchases from market suppliers, and the opportunity to make Third Party Economy Sales at the current market price; and

2.1.6. Transmission constraints or limitations and transmission service contract requirements which would preclude the physical delivery of Energy as contemplated by the Pre-Schedule, including loss factors.

2.2 Resource Revisions to Pre-Schedules.

Resource Pre-Schedules may be revised by AEPCO in advance of any hour to recognize changes in load requirements, generator conditions, transmission outages, market opportunities and such other needs as may occur throughout the day. AEPCO's primary purpose in making such revisions shall be to keep sufficient AEPCO Resources on-line at all times to reliably serve AEPCO Total Load. A secondary purpose shall be to reduce overall operating costs of AEPCO Resources.

3. REGULATORY REQUIREMENTS:

AEPCO shall comply with regulatory requirements of all Governmental Authorities having jurisdiction as such requirements may apply with respect to these Resource Operation and Unit Dispatch Guidelines. In the event of any conflict between such regulatory requirements and these Guidelines, such regulatory requirement shall govern.

4. AEPCO COMMITMENT GUIDELINES FOR OTHER RESOURCES:

The following unit commitment guidelines relate to the start-up and operation of Other Resources. These are intended to recognize Other Resources operation limits in order to preserve their lives and reduce the likelihood of experiencing renovation and/or extraordinary maintenance costs prior to their anticipated retirement at the end of 2020. These guidelines do not prohibit AEPCO from buying from the market in lieu of starting and operating these units at any time. The guidelines shall be as follows:

4.1 For peaking GT Units 1 and 3: These units shall be reserved for dispatch basically in super-peak hours (HE 1200 through HE 2000) in summer months of June through September (exception: GT-1 when used with Steam 1 in CC operation)

4.1.1 No nighttime commitment (off-peak hours Monday through Saturday, Sunday HE 2300 – HE 0700).

4.1.2 No winter commitment except if necessary to cover superpeak daytime periods during base load unit maintenance outages.

4.2 For peaking GT Unit 2: This unit shall not be operated and shall be held in reserve for meeting 20 MW of AEPCO's non-spinning reserve requirements, but may be started and dispatched as called upon to fulfill reserve obligations.

4.3 For peaking GT Unit 4: This unit shall be available for operation in Peak Hours and Sunday HE 0800 through HE 2200 throughout the summer period, in winter peak months (December, January), and during coal unit Existing Resource maintenance or forced outages. When operating, a portion of its Capacity as needed shall be set aside for supplementing the Spinning Reserves supplied from coal-fired Existing Resources.

4.4 For Steam 1 (in CC or not): This unit shall be available in the summer period (May through October) for daily operation around the clock as may be required to preserve load serving capability and backup to forced outage of coal-fired Existing Resources. Winter period use is permitted during coal unit maintenance outage periods and during winter peak months of December and January, but every effort should be made to utilize market purchases prior to committing the unit in winter months.

5 GUIDELINES FOR AEPCO PURCHASES AND SALES:

5.1 Maintenance Purchases.

In the event an AEPCO Resource is out of service for planned maintenance or otherwise has been taken off-line and a Replacement Purchase is needed to meet AEPCO Total Load, AEPCO may locate and contract for the replacement of such AEPCO Resource for the expected deration of the Resource outage.

5.2 Economy Sales and Economy Purchases.

5.2.1 General.

AEPCO shall at all times be cognizant of the opportunities to make and shall make appropriate Third Party Economy Sales from AEPCO Resources (with the exception of power purchased under Federal Hydro Power Agreements) and Non-Base Economy Purchases against AEPCO Resources to realize the optimum cost of Resources in the Pre-Schedule for serving AEPCO Delivered Load. Any single such Third Party Economy Sale and any single such Non-Base Economy Purchase shall not extend beyond the subsequent twelve calendar months nor exceed duration of

twelve (12) consecutive months, and otherwise shall be made in accordance with the following:

5.2.2 Economy Sales.

At any time that Capacity and Energy from an AEPCO Resource is available for sale and can be sold without jeopardizing system reliability and taking into consideration the factors governing such Resource as set forth in Section 2.1 above, AEPCO may Pre-Schedule such a sale. The price related to such Economy Sale shall exceed such Resource's marginal cost (including appropriate allowances for fixed and variable costs as determined by AEPCO from time to time) plus transmission service and ancillary services costs and losses, as applicable (Resource Cost).

5.2.3 Dump Energy Sales.

At any time that an AEPCO Resource must be maintained online for testing or for meeting subsequent hours' loads and is not otherwise needed to serve current loads, AEPCO may sell the energy surplus of such Resource as dump energy at the prevailing market price without regard to such Resource's Resource Cost.

5.2.4 Non-Base Economy Purchases.

AEPCO may Pre-Schedule a Non-Base Economy Purchase at any time an AEPCO Resource that is (i) currently being dispatched, (ii) can be taken and remain off line for the purchase period without jeopardizing system reliability, and (iii) will be replaced with a capacity or energy purchase at a price lower than its Resource Cost.

5.3 Energy Purchase for Sale.

AEPCO may from time to time enter into purchases of energy at wholesale from third party suppliers to substitute for Resources that could otherwise be dispatched (or as a temporary replacement for Resources out of service as an alternative to interrupting the sale) to support sales at wholesale from AEPCO Resources (Purchases for Sale), subject to the following:

5.3.1 The Resource Cost of such purchases plus the cost of other Resources being used to make the sale (including delivery costs and losses) shall be less than the price received from the sale;

5.3.2 Such Purchases for Sale shall not increase the operating reserve requirements or otherwise increase costs to AEPCO unless such costs are recovered in the sale price; and (iii) such purchase shall be for a deration of no greater than the deration of the sale which it supports.

EXHIBIT C

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.

FIRST AMENDMENT TO PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

This First Amendment to the Partial Requirements Capacity and Energy Agreement (SSVEC PRC&EA) is entered into this 11 day of May, 2010, by and between Sulphur Springs Valley Electric Cooperative, Inc., a non-profit corporation organized and existing under the laws of the State of Arizona (Member) and Arizona Electric Power Cooperative, Inc., a non-profit cooperative corporation organized and existing under the generation and transmission electric cooperative laws of the State of Arizona (AEPCO). Member and AEPCO are also hereinafter referred to individually as "Party" or collectively as "Parties."

WHEREAS, the Parties have entered into that certain Partial Requirements Capacity and Energy Agreement dated December 29, 2005 (Partial Agreement) such that Member pursuant to the Partial Agreement is an "AEPCO Partial Requirements Member," as that term is defined in the Amended and Restated Appendix A dated May 11 2010, attached hereto and referred to herein as the "2010 Definition Appendix";

WHEREAS, the Parties intend to modify as among themselves, the manner in which rates, charges and Fixed Charges for electrical service to Member are formulated and designed in order to effect resolution of certain Rate Allocation Issues and Rate Design Issues which have developed among AEPCO and the AEPCO Class A Members, as all such capitalized terms are defined in the 2010 Definition Appendix, pursuant to the Rate Settlement Agreement dated May 14, 2010 (Rate Settlement Agreement);

WHEREAS, the Parties recognize the benefit in entering into this Amendment in order to settle the Rate Allocation Issues and Rate Design Issues, by providing for a fair, equitable and repeatable allocation of costs and revenues at issue between the PRMs and ARMs based on principles of cost causation;

WHEREAS, the Parties intend that this Amendment shall be an integral component of the Rate Settlement Agreement;

WHEREAS, AEPCO filed on October 1, 2009, an application with the Arizona Corporation Commission (ACC) in ACC Docket No. E-01773A-09-0472 to modify its rates and charges (AEPCO 2009 Rate Application);

WHEREAS, this Amendment is intended to be entered into contemporaneously with certain other substantially identical amendments to individual partial requirements capacity and energy agreements between AEPCO and the other Partial Requirements Members of AEPCO, as defined in the 2010 Definition Appendix;

WHEREAS, it is in the best interest of Member and its members to enter into this Amendment to implement the changes in AEPCO's rate formulation herein contemplated, thereby partially implementing the Rate Settlement Agreement; and

WHEREAS, the Parties wish to amend the Partial Agreement, as set forth in this Amendment;

NOW, THEREFORE, in consideration of the premises set forth above and for good and valuable consideration, the receipt and sufficiency of which the Parties hereby acknowledge, the Parties hereto, intending to be legally bound, mutually agree as follows:

Section 1. Effective Date:

This First Amendment to SSVEC PRC&EA shall become effective on the first day of the month following the latter of 1) the date of its approval by the Rural Utilities Service (RUS), 2) the date of approval by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

Section 2. Amendment to Section 2.1.2:

Section 2.1.2 Delete the words "take and pay, or" from the first line.

Section 3. Amendment to Section 2.1.3:

Section 2.1.3 Shall be deleted in its entirety.

Section 4. Amendment to Section 2.6.1:

Section 2.6.1 shall be deleted in its entirety and replaced with the following:

"The Member shall have an unconditional obligation to make all payments to AEPCO required hereunder at the rates and charges and on the terms and conditions set forth herein and in Rate Schedule A. The Member shall make all payments of charges and energy charges for capacity and energy provided for under this Agreement, including without limitation, rates and charges resulting from all Required Modifications and Minor Resource, 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.

Section 5. Amendment to Section 3.4.4 (d) (ii) (c):

Section 3.4.4 (d) (ii) (c) shall be deleted in its entirety and replaced with the following:

"(c) the rates and charges 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."

Section 6. Amendment to Section 5.1:

The last two (2) sentences of Section 5.1 shall be deleted in their entirety and replaced with the following:

"Member shall make all payments to AEPCO that are required pursuant to this Agreement at the rates, charges, 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 5.6 hereof. All such rates, charges 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."

Section 7. Amendment to Section 5.3:

Section 5.3 shall be deleted in its entirety and replaced with the following:

"O&M Charge. AEPCO shall charge, and the Member shall pay all operations and maintenance costs and expenses based on its ACP 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."

Section 8. Amendment to Section 5.4:

Section 5.4 shall be deleted in its entirety and replaced with the following:

"Energy Charges. Subject to Schedule B 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 monthly energy charges as determined, and set forth in, and due and payable, pursuant to Rate Schedule A."

Section 9. Amendment to Section 5.6:

Section 5.6 shall be deleted in its entirety and replaced with the following:

"Rate and 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 charges for electric energy and capacity provided hereunder, under any Partial Requirements Capacity and Energy Agreement with any other Class A Member, and under the Existing

Wholesale Power Contracts with AEPCO's All Requirements Members. If such rates or charges 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 charges with the effective date thereof, and the basis upon which the rates or charges are proposed to be adjusted and set. The Member agrees that the rates and charges 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 charges pursuant to such revised rates and charges; provided that no such revised rates or charges shall be effective if they have been disapproved in writing by the Administrator. AEPCO shall design and set future rates and charges 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."

Section 10. Amendment to Section 5.7:

Section 5.7 shall be deleted in its entirety and replaced with the following:

"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 charges charged to the Member in accordance with Rate Schedule A."

Section 11. Amendment to Section 5.9:

Section 5.9 shall be deleted in its entirety and replaced with the following:

"Reasonable Rate. The Parties agree that the rates, charges, rate methodology, and 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 charges 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 charges 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."

Section 12. Amendment to Section 5.11:

Section 5.11 shall be deleted in its entirety and replaced with the following:

"Cost Responsibility. The rates and charges 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 among the AEPCO 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."

Section 13. Amendment to Section 5.12:

Section 5.12 shall be deleted in its entirety and replaced with the following:

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

Section 14. Amendment to Section 6.2.5:

Section 6.2.5 shall be deleted in its entirety and replaced with the following:

"The Parties agree that the rates and charge methodology and principles of cost allocation set forth in this Agreement are just and reasonable."

Section 15. Amendment to Section 16.1 (b):

Section 16.1(b) shall be deleted in its entirety and replaced with the following:

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

Section 16. Amendment to Section 10 Committees:

Section 10 is hereby amended in its entirety and replaced with the Section 10 attached hereto as set forth in its entirety as Attachment 1.

Section 17. 2010 Definition Appendix:

Appendix A is hereby amended in its entirety and replaced by the Amended and Restated Appendix A dated May 11 2010, attached hereto.

Section 18. Amendment to Rate Schedule A and all revisions thereto, attached to the Partial Agreement:

Rate Schedule A attached to the Partial Agreement and all revisions thereto shall be amended in its entirety and replaced with the Rate Schedule A dated May 11 2010, attached hereto as Attachment 2.

Section 19. Amendment to Schedule B and all revisions thereto, attached to the Partial Agreement:

Schedule B attached to the Partial Agreement and all revisions thereto shall be amended in its entirety and replaced with the [redacted] Schedule B dated May 11, 2010, attached hereto as Attachment 3.

Section 20. Miscellaneous:

(a) Extent of Amendment. Except as expressly herein set forth, all of the terms and conditions of the Partial Agreement are herein ratified and confirmed and shall remain in full force and effect.

(b) Counterparts. This Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Amendment by signing any such counterpart.

(c) Binding Effect. This Amendment shall be binding upon the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the undersigned have duly executed this First Amendment to Partial Agreement, effective as of the date set forth below.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

By: ____________________
Name: Gary G. Grim
Title: Senior Vice President and Chief Operating Officer
Date: 5/11/10

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.

By: ____________________
Name: ____________________
Title: ____________________
Date: ____________________

Section 18. Amendment to Rate Schedule A and all revisions thereto, attached to the Partial Agreement:

Rate Schedule A attached to the Partial Agreement and all revisions thereto shall be amended in its entirety and replaced with the Rate Schedule A dated May 11, 2010, attached hereto as Attachment 2.

Section 19. Amendment to Schedule B and all revisions thereto, attached to the Partial Agreement:

Schedule B attached to the Partial Agreement and all revisions thereto shall be amended in its entirety and replaced with the [redacted] Schedule B dated May 11, 2010, attached hereto as Attachment 3.

Section 20. Miscellaneous:

(a) Extent of Amendment. Except as expressly herein set forth, all of the terms and conditions of the Partial Agreement are herein ratified and confirmed and shall remain in full force and effect.

(b) Counterparts. This Amendment may be executed in any number of counterparts, and all of which when taken together shall constitute one and the same instrument. The Parties hereto may execute this Amendment by signing any such counterpart.

(c) Binding Effect. This Amendment shall be binding upon the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the undersigned have duly executed this First Amendment to Partial Agreement, effective as of the date set forth below.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

By:____________________
Name:____________________
Title:____________________
Date:____________________

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.

By: Dan Barrera
Name: Dan Barrera
Title: President
Date: 5/10/10

ATTACHMENT 1 to First Amendment to Partial Agreement

Section 10. Operations Review Committee.

10.1 The Class A Members of Generating Cooperative (Class A Members), including Member, shall have an opportunity to make recommendations to the Operations and Construction Committee (OCC) and the Finance and Audit Committee (FAC) of the Board of Directors of Generating Cooperative (AEPCO) and to the AEPCO Board as described below on any matters that relate to the service and cost of the service provided by AEPCO to Member through the representative of each on a committee (Representative) herein designated as the Operations Review Committee (Committee).

10.2 The Committee shall consist of one authorized Representative from each Class A Member and a Representative designated by AEPCO, who shall serve as Chairperson of the Committee. Each Class A Member shall designate as its Representative an employee of such Class A Member with experience in the areas in which the Committee will function and AEPCO shall designate the Chairperson, who shall be an AEPCO employee.

10.3 Each Class A Member shall evidence the appointment of its Representative by written notice to the other Class A Members and AEPCO, and by similar notice, any Class A Member or AEPCO may change its Representative on the Committee at any time. The list of Committee Representatives will be updated by the Chairperson and distributed to each of the Class A Members with appropriate contact information as necessary to keep the list current as to representation on the Committee.

10.4 Each Class A Member shall be entitled to one vote through its Representative on matters that come before the Committee. In the absence of unanimous consent, the various positions of the Representatives shall be compiled, referred and communicated to the OCC and or FAC by those Representatives electing to do so.

10.5 The Committee shall meet in person or telephonically quarterly except as otherwise determined by the Committee, but in no event less frequently than annually. The Representatives shall determine the agenda of the Committee and have access to all information related to the resources used by AEPCO to provide service.

10.6 Prior to the beginning of each calendar year, and as may be required during any such calendar year, an agenda for the Committee meeting will be solicited from the Representatives and the Committee will receive, consider and review all information requested by the Committee including but not limited to the Apache Station Operations and Maintenance Budget, Capital Budget and Construction Work Plans, A & G expenses proposed by AEPCO management, load forecasts, financial forecasts, cash flow forecasts, rate filings and forecasts, and review variances, updates and amendments thereto and such other operations data as may be requested. Following consideration thereof by the Committee, the Chairperson will promptly report to either the OCC or the FAC, as appropriate, such recommendations concerning any issues considered together with alternatives raised by a Representative. The Representatives may make reports through the AEPCO Director for the Member they represent on the positions they sponsor if they differ from the Committee recommendation report to the OCC or the FAC. Such reports to the OCC and the FAC given by the Chairman and the sponsoring Director(s) shall present all alternatives considered by the Committee in addition to the recommendations of the Committee. Representatives of the Committee may assist in the presentation by their Director(s) of alternatives considered by the Committee for the Board's review in making the final Board decision.

Appendix A
Amended and Restated Definitions

APPENDIX A

AMENDED AND RESTATED: DEFINITIONS
DATED May 11, 2010

1. These Definitions shall have the respective meanings set forth herein for use in the following agreements and their exhibits and schedules (unless the context in which the term is used in a particular agreement clearly requires otherwise):

    1. MEC Partial Requirements Capacity and Energy Agreement;
    2. SSVEC Partial Requirements Capacity and Energy Agreement;
    3. TRICO Partial Requirements Capacity and Energy Agreement;
    4. Resource Integration Agreement;
    5. SSVEC Transmission Agreement;
    6. MEC Transmission Agreement;
    7. TRICO Transmission Agreement;
    8. Network Service Agreement;
    9. Member Agreement between AEPCO, SWTC, Sierra and ANZA, DVEC, GCEC, MEC, SSVEC and TRICO.

2. These Definitions shall not be amended or modified without advance notice, review and approval by all parties to any of the agreements listed above, and RUS (as hereinafter defined), which remain executory, and after providing to all parties in advance a listing of any such agreements in which a proposed amended or modified defined term is contained.

3. The following shall be used in interpreting these Definitions and the agreements listed above:

    3.1 Unless otherwise required by the context in which any term appears:

    (a) Capitalized terms used in any agreement listed above shall have the meanings specified in this Appendix A or, if used solely within an Agreement, as set forth in such agreement.

    (b) The singular shall include the plural and the masculine shall include the feminine and neuter.

    (c) References to "Articles," "Sections," "Schedules," "Appendices" or "Exhibits" shall be to articles, sections, schedules, appendices, or exhibits of the agreement(s) specified, and references to paragraphs shall be to separate paragraphs of the section or subsection in which the reference occurs.

    (d) The words "herein," "hereof", "hereinbelow" and "hereunder" shall refer to an agreement, specified as a whole and not to any particular section or subsection of such agreement; the words "include," "includes" or "including" shall mean "including, but not limited to"; and the words "best effort(s)" shall mean a level of effort which, in the exercise of reasonable judgment in the light of facts known at the time a decision is made, can

be expected to accomplish the desired result at a reasonable cost, consistent with Prudent Utility Practice (as hereinafter defined).

(e) Except where the context otherwise indicates, the term "day" shall mean a calendar day, and whenever an event is to be performed by a particular date, or a period ends on a particular date, and the date in question falls on a weekend, a legal holiday in the State of Arizona, or a day when the relevant cooperative is not open for business, the event shall be performed, or the period shall end, on the next succeeding business day.

(f) All accounting terms not specifically defined herein or by specified Accounting Requirements (as hereinafter defined) shall be construed in accordance with Generally Accepted Accounting Principles in the United States of America, consistently applied.

3.2 All references herein to the term "cooperative" shall be to AEPCO, TRANSCO, CSP or a Member (as hereinafter defined) cooperative as appropriate from the context in an agreement.

3.3 All references to a particular entity shall include such entity's successor and permitted assigns.

3.4 All references herein to any agreement, including its schedules, exhibits and appendices, shall be to such agreement as amended, supplemented or modified.

3.5 All references herein to any Law (as hereinafter defined) shall be to such Law as amended, supplemented, modified or replaced.

3.6 The titles of the articles and sections of the agreements have been inserted as a matter of convenience of reference only and shall not control or affect the meaning or construction of any of the terms or provisions thereof.

3.7 The parties have agreed to the wording of the agreements, and none of the provisions thereof shall be construed against one party on the ground that any party is the author of such agreement or any part thereof.

3.8 In any defined term which begins with the word "PRM*," the word PRM* may be replaced with the name of a Partial Requirements Member. When the name of a Partial Requirements Member is substituted, the definition remains the same but is applicable only to the named Partial Requirements Member. For example, "'PRM* Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load." If MEC is substituted, "'MEC Transmission Service' shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of MEC to MEC AEPCO Load."

"AC" shall mean Allocated Capacity.

"ACC" shall mean Arizona Corporation Commission or any State of Arizona regulatory agency succeeding to its powers and functions.

"Accounting Report" shall mean the report prepared by TRANSCO that accounts for all of the installed cost of each transmission facility constructed or acquired by TRANSCO as a part of the TTS and classifies such facility or portion thereof and apportions its installed cost as an All Requirements Resource Facility, an Existing System Facility, a Load Growth System Facility, a Power Sale Resource System Facility, a Resource Facility, or a Reliability System Facility, for the purposes of Sections 2 and 6 hereof and consistent with Accounting Requirements.

"Accounting Requirements" shall mean the requirements of any system of accounts prescribed by the RUS as long as RUS is the holder of any obligation of a cooperative; provided, however, that if a cooperative is specifically required by another Governmental Authority to employ the system of accounts prescribed by that Governmental Authority, then "Accounting Requirements" means the system of accounts prescribed by that Governmental Authority; provided, further, however, that if RUS is not a holder of any obligation or, if a holder, RUS does not prescribe a system of accounts applicable to the cooperative, and the cooperative is not specifically required by another Governmental Authority to employ that entity's system of accounts, then "Accounting Requirements" means the requirements of Generally Accepted Accounting Principles or another comprehensive basis of accounting applicable to like entities conducting business similar to that of the cooperative. Generally Accepted Accounting Principles refers to a common set of accounting standards and procedures that are either promulgated by an authoritative accounting rulemaking body or accepted as appropriate due to widespread application in the United States.

"Additional AEPCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by AEPCO.

"Additional CSP Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by CSP.

"Additional TRANSCO Contract" shall mean each additional contract (set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement as the case may be) which either the Member Agreement or the Restructuring Agreement requires to be executed and delivered by TRANSCO.

"Administrator" shall mean the Administrator of RUS or any other federal regulatory agency or department succeeding to the Administrator's power or functions as a lender or mortgagee to a cooperative.

"AEPCO" shall mean Arizona Electric Power Cooperative, Inc., a non-profit generation and transmission cooperative corporation organized under the Laws of the State of Arizona.

"AEPCO Available Resource(s)" shall mean that portion of AEPCO Resources representing operating reserves which can be sold on an interruptible basis and surplus to AEPCO Total Load.

"AEPCO By-law Amendments" shall mean the amendments to the AEPCO By-laws relating to governance, in the form adopted by AEPCO in accordance with the terms of the AEPCO By-laws and the Laws of the State of Arizona.

"AEPCO By-laws" shall mean the By-laws adopted and amended by the Members or Board of Directors of AEPCO in accordance with the Laws of the State of Arizona.

"AEPCO Class A Member" shall mean (i) any Class A Member which purchases power and energy from AEPCO pursuant to any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement and is listed in Recital B to the Partial Requirements Capacity and Energy Agreement; or (ii) is determined to be a Class A member by the terms of the AEPCO By-laws.

"AEPCO Closing Date Allocation and Attribution" shall mean the allocations and attributions to be made by AEPCO on the Closing Date, as set forth in Section 2.6 of the Member Agreement and Section 2.3 of the Restructuring Agreement.

"AEPCO Delivered Load" shall mean the aggregate of the demand requirements and the associated energy requirements of all electric loads served from AEPCO Resources (including distribution losses but not including reserves or transmission losses), and shall consist of:

1. The loads of All Requirements Members served from AEPCO Resources;
2. PRM*AEPCO Load;
3. PRM*AEPCO Sales;
4. Power Sales Loads; and
5. CSP AEPCO Load.

"AEPCO Employees" shall mean those individuals employed by AEPCO as of the Closing Date.

"AEPCO Federal Hydro Power Capacity" shall mean that amount of capacity on an hourly basis scheduled by AEPCO pursuant to Federal Hydro Power Agreements.

"AEPCO Load Forecast" shall mean a listing of the demand and associated energy requirements of AEPCO Total Load (by month for the Resource Forecast Period) to be served from AEPCO Resources

"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 the Partial Requirements Capacity and Energy Agreements and the Existing Wholesale Power Contracts.

"AEPCO Minimum Base Capacity" shall mean the capacity from Available Base Capacity that must be operated from time to time to maintain system reliability or for other reasons, reflecting AEPCO's determination as to the schedule of energy from the Federal Hydro Power Agreements and AEPCO Minimum Coal Capacity.

"AEPCO Minimum Coal Capacity" shall mean the minimum output for safe and reliable operation of Apache Units 2 and 3.

"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.

"AEPCO Notes" shall mean written instruments or notes which evidence the obligation of AEPCO for loans that in whole or in part financed the construction of AEPCO's generation and transmission facilities, the payment of which is guaranteed by the Government pursuant to the REAct, and those written instruments or notes of AEPCO outstanding on the Effective Date (with respect to the MEC Partial Requirements Capacity and Energy Agreement), the Agreement Date (with respect to the SSVEC Partial Requirements Capacity and Energy Agreement), or the Approval Date (with respect to the TRICO Partial Requirements Capacity and Energy Agreement) payable to the Government evidencing loans made by the Government, acting by and through the Administrator of RUS, pursuant to the REAct, or evidencing reimbursement obligations of AEPCO to the Government with respect to the Government's guarantee of the payment of certain notes payable to the order of FFB and all amendments, supplements, extensions, and replacements to, of, or for, such notes, and loans made by, or securities issued to, or obligations undertaken to, others, including the Financial Entities. AEPCO Notes in the future will also include written instruments, which may evidence additional or new loans or advances that AEPCO may obtain to finance the construction or purchase of new facilities, Future Resources or the modification of Existing Resources, as applicable.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Retained Personnel" shall mean AEPCO management and other personnel designated as such by the chief executive officer of AEPCO.

"AEPCO's Revenue Requirement" shall mean the total revenues, from any source whatsoever, necessary to enable AEPCO, utilizing a twelve (12) 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) include 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, determined in accordance with Accounting Requirements.

"AEPCO's Revenue Requirement from AEPCO's Class A Members" shall mean that portion of AEPCO's Revenue Requirement less revenues anticipated by AEPCO from all other sources than the AEPCO Class A Members.

"AEPCO's Revenue Requirement From Partial Requirements Members" shall mean that portion of AEPCO's Revenue Requirement from AEPCO Class A Members allocated to Partial Requirements Members in accordance with Section 5 of the Partial Requirements Capacity and Energy Agreements and Section 3 of Rate Schedules A.

"AEPCO Scheduling Portal" shall mean an Internet web site maintained by AEPCO and accessible by all Class A Members for the purpose of AEPCO posting ongoing information relating to the availability and minimum must run requirements for AEPCO Resources.

"AEPCO Secured Obligations" shall mean the AEPCO Notes, loans made by, or securities issued to, or debt obligations entitled to the lien created by the AEPCO Mortgage.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Agreement Date" shall mean the first day of the month following the date upon which the SSVEC Partial Requirements Capacity and Energy Agreement, the SSVEC Transmission Agreement and the Resource Integration Agreement, as amended to include SSVEC, shall have been executed and delivered by the necessary parties and approved by the RUS and, if required, by the ACC and FERC.

"All Requirements Member" shall mean any Class A Member of AEPCO that is currently a party to any Wholesale Power Contract with AEPCO which provides for the purchase from AEPCO of all such Member's requirements of electric power, which as of the Effective Date consisted of ANZA, DVEC, GCEC, SSVEC AND TRICO, which as of the Agreement Date consisted of ANZA, DVEC, GCEC and TRICO, and which as of the Approval Date shall consist of ANZA, DVEC and GCEC.

"All Requirements Resource Facility" shall mean any System Facility, or portion hereof, or Direct Assignment Facility that is required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future resource in which MEC and SSVEC have no ACP.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in its Partial Requirements Capacity and Energy Agreement. The AC for each

month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of such agreement.

"Allocated Capacity Percentage" or "ACP" of a Class A Member shall mean the percentage allocation with respect to an AEPCO Resource, for which, if it is a Partial Requirements Member, such Member is responsible, including the allocation of electric capacity, cost responsibility and revenues, as set forth in its Partial Requirements Capacity and Energy Agreement. Appendix A to Exhibit A-5 to Rate Schedule A sets forth the ACP for each Class A Member with respect to Existing Resources and the S&G PPA.

"Ancillary Services" shall mean the ancillary services required by FERC to be made available with transmission service in accordance with the FERC pro-forma open access transmission tariff, including; but not limited to scheduling, system control and dispatch service; reactive supply and voltage control from generation sources service; regulation and frequency response service; energy imbalance service; operations reserve-spinning reserve service, and; operating reserve - supplemental reserve service, all as such terms are further defined by FERC in Order No. 888 and 889 and identified in transmission tariffs and service agreements of TRANSCO.

"Annual Planning Report" shall mean the annual written report and analysis given to AEPCO of a Class A Member's short, intermediate and long-range forecast of load and such other planning data required by the Resource Integration Agreement.

"Annual Transmission Requirements Report" shall have the meaning set forth in Section 5 of Schedule B hereto (Transmission Planning Policies).

"ANZA" shall mean Anza Electric Cooperative, Inc., a non-profit electric cooperative corporation organized and existing under the Laws of the State of California.

"Applicable Additional Contract" shall mean each additional contract as set forth on Schedule 1 of the Member Agreement and Schedule 6 of the Restructuring Agreement, which either the Restructuring Agreement or the Member Agreement requires to be executed by each party to the Agreements.

"Approval Date" shall mean the first day of the month, no earlier than December 1, 2010, following the latter of 1) the date upon which the TRICO Transmission Agreement and the TRICO PRC&EA shall have been approved by the RUS, 2) the date upon which the TRICO PRC&EA shall have been approved by the ACC or 3) the effective date of a non-appealable decision in AEPCO's 2009 Rate Application, or its replacement.

"ARM Energy Cost Responsibility Share or ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Assignment for Security" shall mean an assignment, transfer, mortgage or pledge of a party's interest in an Agreement made as security for any obligation secured by any

indenture, mortgage, deed, deed of trust, security instrument, or similar lien on its system assets, without limitation on the right of the secured party to further assign such Agreement.

"Authorized Representative" shall mean a representative designated by a party pursuant to the terms of an Agreement and authorized to act for such party in certain matters as set forth in the relevant terms of such Agreement.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available Resource(s)" shall mean the Pooled Resource(s) surplus to Pooled Load available for sale or dispatch as Merchant Sales.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Available Transmission Resources" shall mean the transmission facilities and contract rights of the Parties (as set forth in Schedule E attached) required for the delivery of Pooled Resources to Pooled Loads.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer Energy of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"Bonds" shall mean the CFC Guaranteed Solid Waste Disposal Revenue Bonds (Series 1994Adw) and the CFC Guaranteed Pollution Control Revenue Refunding Bonds (Series 1997C).

"CARM or Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources applicable to each All Requirements Member of AEPCO as set forth in Appendix A to Exhibit A-5 to the Rate Schedule A of the ARM Wholesale Power Contracts.

"CFC" shall mean the National Rural Utilities Cooperative Finance Corporation, a corporation organized under the Laws of the District of Columbia, or similar successor agency.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's By-laws.

"Closing" shall mean the execution and delivery of any and all documents and the tendering, transferring or delivering of all payments required to be made or otherwise necessary or desirable to consummate the transactions contemplated by the Restructuring Agreement and the Member Agreement, including such actions and documents described in the Closing Memorandum as specified in Section 8.1 of both the Restructuring Agreement and the Member Agreement, following satisfaction or waiver, if any, of the conditions for Closing therein.

"Closing Date" shall mean the date on which the Closing occurs.

"Closing Memorandum" shall mean the memorandum agreed to by the parties to the Member Agreement prior to the Pre-Closing which sets forth the consents, assignments, transfers, delivery of other approvals, documents, legal opinions, payments and transaction documents to be furnished by the parties, other conditions for Closing, and events and actions required to effect the Closing

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Collected Funds" shall mean deposited funds in a banking institution that are immediately available for use without any float restrictions.

"Contract Rate of Interest" shall mean the lesser of: (i) the interest rate equal to the effective "Prime Rate" per annum as specified in the "Money Rates" section of the Wall Street Journal or, (ii) the maximum interest rate permitted by applicable Law in the State of Arizona if any is so stated.

"Cost Causation" shall mean the identification of all direct and indirect costs, revenue and billing units associated with individual Resources and services, such that costs, revenue and billing units can be accounted for and billed separately to the specific Class A Members participating in such Resource or receiving such service.

"CSP" shall mean Sierra Southwest Cooperative Services, Inc., a non-profit corporation organized under the generation and transmission cooperative corporation Laws of the State of Arizona.

"CSP Actual AEPCO Load Data" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP AEPCO Load" shall mean the sum of the demand and associated energy requirements, including distribution losses, but not including reserves or transmission losses, of the Member JMP Load of each Class A Member and of those other loads for which CSP purchases capacity and energy from AEPCO as specified in separate sales agreements between AEPCO and CSP.

"CSP AEPCO Load Forecast" shall have the meaning set forth in Section 4 of the Resource Planning Policies.

"CSP Assets" shall mean all capital stock of TSEPP, personal property, authorization to make Retail Sales, intangible assets, employee benefit plans, intellectual property, software licenses, employee or consultant agreements, equipment leases and contracts, licenses, any chose in action, and other agreements related to the performance of the CSP Business identified on Schedule 2 to the Restructuring Agreement.

"CSP Business" shall mean (i) the business of power sales and retail sales; (ii) the provision of personnel and consulting services to AEPCO, TRANSCO, and others pursuant to contract; and, (iii) the ownership and use of the CSP Assets, including responsibility for CSP Liabilities.

"CSP JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of those loads within a Member's Distribution Service Area served using capacity and energy provided by CSP from CSP Resources pursuant to a Joint Marketing Agreement between a Class A Member and CSP.

"CSP Liabilities" shall mean (i) the CSP liabilities identified on Schedule 2 to the Restructuring Agreement, as such obligations exist as of the Closing Date; and (ii) such other obligations relating to the performance of the CSP Business as CSP, AEPCO and TRANSCO may agree upon from time to time in other agreements; and (iii) any liabilities which CSP assumes in accordance with its By-laws.

"CSP Member" shall mean AEPCO, TRANSCO and the Class A Members of AEPCO on the Closing Date and any Person, which has become and retains membership in CSP in accordance with the CSP By-laws.

"CSP Resource" shall mean a Resource owned or purchased by CSP from third parties.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Debt Service Coverage Ratio" or "DSC" shall mean the financial ratio determined, based on figures shown on RUS Form 12 for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) depreciation and amortization expense, (b) interest on long-term debt (increased by one-third of the amount, if any, by which long-term leases exceed two percent of total margins and equities less regulatory assets), and (c) net patronage capital or margins and (2) dividing the sum obtained by the total of interest and principal billed under long-term debt and debt service requirements.

"Deficiency Purchase" shall mean the purchase of additional capacity and energy through the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1.1 herein, which purchase is required to supply capacity and associated energy to meet AEPCO Total Load, if it is the Purchasing Party, or MEC Total Load if MEC is the Purchasing Party.

"Delivery Point" shall mean the interconnection between the TTS and the transmission, distribution system or load of a Class A Member at which TRANSCO is to deliver capacity or energy pursuant to the Transmission Agreement or the Network Service Agreement.

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

"Direct Assignment Facilities" shall mean those transmission lines, substation facilities (or components thereof) and firm wheeling purchased by TRANSCO, for the sole use and benefit of a TRANSCO Member or of a particular transmission customer receiving service under the TRANSCO Tariff.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.

"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"DVEC" shall mean Duncan Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Economy Purchase(s)" shall mean a wholesale purchase of capacity and/or energy for a term not to exceed one year (including all renewal periods) entered into by AEPCO.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sale(s)" shall mean a wholesale sale by AEPCO of capacity and energy from AEPCO Available Resources made for monthly, daily or hourly periods of the next twelve months on a pre-scheduled basis.

"Economy Sales Price" shall mean for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Effective Date" shall mean either (i)________________, or (ii) the Closing Date.

"Eligible Customer For TRANSCO " shall mean any of the following: (i) any electric utility (including AEPCO, CSP or any power marketer), Federal Power Marketing Agency, or any Person generating electric energy for sale for resale (electric energy sold or produced by any such entity may be produced in the United States, Canada or Mexico) or (ii) any Person offering retail electric service to others or taking retail service pursuant to a state requirement that TRANSCO offer unbundled transmission service or to a voluntary offer of such service by TRANSCO.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Engineering Analysis Requirement" shall mean have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.

"Equity" shall be defined in accordance with Accounting Requirements.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G and Supplemental Billing Energy.

"Exercise Date" shall mean date certain on or before which The Possible Selling Party or Parties shall provide notice to the Purchasing Party or Parties of an election pursuant to Section 10.1.1 herein to exercise The First Right of Refusal among AEPCO and MEC.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth and designated as Existing Resources in Appendix B to Exhibit A-5 to Rate Schedule A, consisting of Base Resource(s) and Other Resource(s).

"Existing System Facility" shall mean any System Facility that is in service or has been acquired as of the Agreement Date, and improvements thereto and replacements thereof occurring during the term of the Agreement.

"Existing Wholesale Power Contract" shall mean the Wholesale Power Contract between AEPCO and a Class A Member, and when used in the plural shall mean such contract and similar contracts between AEPCO and each of the Class A Members pursuant to which, in either case, such Class A Member purchases or purchased all its requirements of electric power from AEPCO prior to its becoming a Partial Requirements Member.

"FERC" shall mean the Federal Energy Regulatory Commission, an agency of the United States Department of Energy, or regulatory agency succeeding to the powers and functions thereof.

"Federal Hydro Power Agreement(s) shall mean 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 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).

"FFB" shall mean the Federal Financing Bank, an instrumentality and wholly owned corporation of the Government or any agency or department of the Government succeeding to the powers and functions thereof.

"Final Load Ratio Share of PRM*" shall mean the Load Ratio Share of PRM* in effect as of the Last Service Date.

"Financial Entities" shall mean collectively RUS, CFC, FFB, the trustees and bondholders of the Bonds and other lending institutions or issuers of debt who have made loans to or hold securities or other obligations of a cooperative.

"First Right(s) of Refusal" shall mean reciprocal one-time rights of first refusal to sell capacity and associated energy granted by the purchasing party to the selling party pursuant to Section 10.1 of the Resource Integration Agreement. Certain conditional first rights of refusal provided by CSP to AEPCO as set forth in Section 14 of the Resource Integration Agreement shall not be deemed to form a part of this defined term.

"First Right(s) of Refusal Period" shall mean the time period during which the First Right(s) of Refusal among AEPCO and MEC pursuant to Section 10.1 of the Resource Integration Agreement shall be in effect commencing on the Effective Date and ending on September 1, 2001.

"Fixed Charge" shall mean the charge computed in accordance with Section 5.2 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Force Majeure" shall mean the occurrence or non-occurrence of any act, event or cause beyond the control of a party to an Agreement whereby the party is unable to perform its obligation, other than the obligation to pay money, which act, event or cause by that party's exercise of due diligence could not have reasonably been expected and avoided, or which even with the exercise of due diligence, the party has not been able to overcome or avoid or cause to be avoided. Such act, event or cause shall include, but not be limited to: acts of God; failure or threat of immediate failure of facilities; explosions, flood, drought, earthquake, storm, fire, pestilence, lightning and other natural catastrophes; epidemic; war; riot; civil disturbance or disobedience, strike, or labor disturbance, disputes or unrest of whatever nature; civil disputes or unrest of whatever nature; labor, material or fuel shortage; sabotage; vandalism; restraint by court order or public authority; a failure or threat of failure of any generating or transmission facility, which is likely to cause an outage of electric service to customers served from that party's system (including transmission curtailments by a transmission provider) or to cause such party to experience a rapid decline in system voltage or frequency; and, action or non action by or inability to obtain the necessary authorizations or approvals from any Governmental Authority (but not including the ACC or RUS), provided however, that no act, event or cause that is the result of the lack of necessary financial resources shall constitute an event of "Force Majeure," nor shall an act, event or cause that is the result of the negligence of the party claiming Force Majeure constitute an event of "Force Majeure."

"Form 12A Balance Sheet" shall mean RUS Form 12a, Section B, Balance Sheet.

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Resource" shall mean (i) any new AEPCO Generating Resource, or (ii) any AEPCO Power Purchase Resource with a term of greater than one (1) year; either of which Resource would require the assignment of a new ACP to each Class A Member participating in such Resource and an amendment, or a new Exhibit to Rate Schedule A.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"GCEC" shall mean Graham County Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona

"Generally Accepted Auditing Standards" shall mean a common set of auditing standards and procedures that have been developed over time by several auditing boards, the most current set of standards and procedures of which is the Auditing Standards Board.

"Generating Resource" shall mean an interest in any existing, additional, modified or repowered generating facility or unit, which may be owned (jointly or individually), leased or otherwise acquired by AEPCO, provided that in connection with any lease of an Existing Resource, such leasehold interest shall not be deemed to be a Future Resource for purposes of the Partial Requirements Capacity and Energy Agreement.

"Generation Business" shall mean with respect to AEPCO: (i) the business of generation of electricity; (ii) operation of the Resource Pool; and, (iii) the use, ownership, rights, obligations and duties associated with the generation assets including its agreements for Power Purchase Resources, Power Sales Resources, Economy Purchases and Economy

Sales including, but not limited to, the Existing Wholesale Power Contracts and the Partial Requirements Capacity and Energy Agreement.

"Government" shall mean the federal government of the United States of America.

"Governmental Authority" shall mean any local, state, regional, federal, or national administrative, legal, judicial, or executive governmental agency, commission, department, or other governmental entity having jurisdiction over AEPCO, TRANSCO, CSP, their respective Members, or any of their activities.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Indebtedness" shall mean:

(1) debt incurred or assumed by a cooperative for borrowed money, or debt incurred for the reimbursement of money advanced under any credit support agreements if in either case categorized as debt according to Accounting Requirements;

(2) lease obligations, if categorized as debt according to Accounting Requirements;

(3) debt incurred or obligations assumed for facilities or power purchases included in a Member's ACP;

(4) debt incurred or obligations issued to finance the amount of a pre-payment; or

(5) debt for any Person (other than debt otherwise treated as Indebtedness hereunder) described in clauses (1), (2), (3) or (4) above which are guaranteed (whether by payment or collection) by the cooperative, provided that none of the following shall constitute Indebtedness:

    (A) guarantees of performance or payment by, or any obligations of, any Person under contracts to pay for fuel for the system; and

    (B) guarantees of performance by any Person for other than payment of debt incurred or assumed for borrowed money, or any obligation if categorized as debt according to Accounting Requirements, including, without limitation, all debt (other than indebtedness otherwise treated as Indebtedness hereunder) for borrowed money or the acquisition, construction or improvement of property or capitalized lease obligations guaranteed directly or indirectly, in any manner by a cooperative, or in effect guaranteed, directly or indirectly, by such cooperative through an agreement, contingent or otherwise, to assume any such indebtedness or to advance or supply funds for the payment or purchase of any such indebtedness or to purchase property or services primarily for the purpose of enabling the debtor or seller to make payment of such indebtedness, or to assure the owner of the indebtedness against loss, because of such indebtedness or to supply funds to or in any other manner invest in the debtor (including any agreement to

pay for property or services irrespective of whether or not such property is delivered or such services are rendered) or otherwise.

"Interest Expense" shall mean an amount constituting interest on long-term Indebtedness (less any interest during construction and allowance for funds used during construction including an interest rate swap collar, floor forward or other hedging agreement, arrangement or security, however denominated) and other interest expense computed in accordance with Accounting Requirements.

"Intra-Day Schedule" shall mean a Real-Time Schedule.

"Joint Marketing Agreement" shall mean an agreement by and between CSP and a Class A Member pertaining to joint competitive retail electric marketing and sales activities, in accordance with applicable Law, within such Member's Distribution Service Area.

"Joint Marketing Plan" shall mean a plan designed by and entered into between CSP and a Class A Member concerning Retail Sales, the form of which is set forth in Exhibit B to the Joint Marketing Agreement.

"Last Service Date" shall mean the last date on which TRANSCO provides service to PRM* pursuant to Section 2 of a PRM* Transmission Agreement, unless otherwise extended by mutual agreement of the Parties as set forth in writing.

"Law" shall mean any applicable treaty, statute, code, constitutional provision, ordinance, rule, regulation, order, judgment, decree, decision, injunction, process or any similar form of legally binding decision or directive issued by any Governmental Authority including permits and regulatory approvals and any applicable common law.

"Legal Requirement" shall mean any obligation of AEPCO or TRANSCO required by Law.

"Load Forecast" shall mean he projections of monthly coincident peak kilowatt and total monthly kilowatt-hour loads of a party to an Agreement.

"Load Growth System Facility" shall mean any System Facility or portion thereof that is not an All Requirements Resource Facility or a Resource Facility and is constructed or acquired by TRANSCO to deliver the power and energy of any Future Resource or Resource Modification to All Requirements Members for serving the portion of total load of All Requirements Members that is in excess of the sum of the collective AC of All Requirements Members in Existing Resources with all Power Sales Resources reduced to zero.

"Load Pool" shall mean those Pooled Loads served from Pooled Resources.

"Load Ratio Share" shall have the meaning set forth in the TRANSCO Tariff.

"Load Ratio Share of PRM*" shall mean the ratio, expressed as a decimal, that results from dividing: (i) the demand of PRM* AEPCO Load at the time of the TRANSCO system Peak, by (ii) the sum of: (a) the actual total of the demands of all firm loads of all TRANSCO

customers at the time of the TRANSCO system peak, including PRM* plus (b) the reserved transmission capacity of all TRANSCO customers receiving firm point to point transmission service under the TRANSCO Tariff, less (c) the actual demands at the time of the TRANSCO system peak of the loads of TRANSCO's customers receiving firm point to point transmission service under the TRANSCO Tariff. Such ratio shall be calculated on a rolling twelve month basis.

"Long Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period extending beyond the subsequent five calendar years.

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

"MEC" shall mean Mohave Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Member" shall mean a member of AEPCO, a CSP Member or a TRANSCO Member, as applicable.

"Member Actual AEPCO Load Data" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member AEPCO Load Forecast" shall have the meaning set forth in Section 3 of the Resource Planning Policies.

"Member Agreement" shall mean the Member Agreement as executed and delivered by and among the Class A Members, AEPCO, TRANSCO and CSP, dated July 2, 2001.

"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's Member Peak Demand purchased by Member from AEPCO pursuant to a PRM* Partial Requirements Capacity and Energy Agreement, which consists of the demands of PRM* AEPCO Load and PRM* AEPCO Sales.

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

"Member JMP Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses of loads located within a Member's Distribution Service Area served using capacity and energy provided by CSP as a result of a Joint Marketing Agreement between CSP and a Class A Member, for which CSP purchases capacity and energy from AEPCO.

“Member Transaction” shall mean (i) the consolidation or merger by the Partial Requirements Member with any other Person; (ii) the reorganization or change of the form of the Partial Requirements Member’s business organization from an electric cooperative non-profit membership-owned corporation; or, (iii) the sale, transfer, lease, or other disposal of all or substantially all the Partial Requirements Member’s assets to any Person (or any effort or agreement therefor), whether accomplished in a single transaction or contemplated through a series of transactions as set forth in Section 12 of the Partial Requirements Capacity and Energy Agreement and the Transmission Agreement.

“Member*” shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

“Member* CA” shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

“Member’s Distribution Service Area” shall mean the geographical electric service territory of a Class A Member as certificated by the ACC, the California Public Utility Commission or the New Mexico Public Utility Commission, as applicable, to supply distribution service as well as all other territory so served by such Class A Member pursuant to applicable Law, or any inter-utility border agreement.

“Merchant Purchase(s)” shall mean a wholesale purchase of capacity and/or energy (pursuant to Section 11 herein) for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to: (i) minimize the cost of energy production from Pooled Resources, and (ii) displace energy from Pooled Resources of higher Pool Price.

“Merchant Sale(s)” shall mean a wholesale sale of capacity and/or energy (pursuant to Section 11 herein) from Surplus Resources for periods occurring in the next twelve months and for a duration not to exceed twelve consecutive months (including all renewal periods) arranged for and entered into by AEPCO as operator of Pooled Resources to use Surplus Resources for the economic benefit of the Pool Resource Owners.

“Minimum Other Capacity” shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

“Minor Resource Modification” shall mean an addition, improvement, repair or modification to an AEPCO Generating Resource or the modification or extension of an AEPCO Power Purchase Resource for five years or less, undertaken by AEPCO in its sole discretion, which will not: (i) increase of greater than ten percent the capacity of the AEPCO Resource being modified; (ii) result in an increase of greater than five percent in AEPCO’s Revenue Requirement From AEPCO’s Class A Members upon the operation of such addition, improvement, repair and modification or extension, as the case may be; or, (iii) extend the term of any Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement.

“Must-Pool Load(s)” shall mean those loads of AEPCO, CSP and MEC which Section 3 herein requires be served from the Resource Pool.

“Must-Pool Resources” shall mean AEPCO Resources and those Resources of CSP and the Partial Requirements Member, which are required to be included in the Resource Pool.

“Native Load” shall mean (i) for AEPCO, the electric load of wholesale power customers of AEPCO on whose behalf AEPCO, by Law, tariff or contract, has undertaken an obligation to construct, or otherwise obtain, reliably operate and provide AEPCO Resources (including Purchase Power Resources of AEPCO) to meet the electric requirements of such customers and shall include, but not be limited to, AEPCO Delivered Load, (ii) for TRANSCO, “Native Load” shall mean the electric loads of the TTS customers on whose behalf TRANSCO, by Law, tariff or contract (including as TTS successor to AEPCO) has undertaken an obligation to construct and operate the TTS and shall include, but not be limited to, AEPCO Delivered Load, and (iii) for a Member, “Native Load” shall mean the electric load of the customers of a Member to whom such Member sells power and/or energy and on whose behalf the Member, by Law, tariff, or contract, has undertaken an obligation to construct, or otherwise obtain, and reliably operate the Member’s system to meet the power supply requirements of such customers.

“Near Term” shall mean” shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period not to exceed the subsequent two calendar years.

“NERC” shall mean the North American Electric Reliability Council, or entity or agency succeeding to its powers and functions.

“Net Utility Plant” shall mean total utility plant less accumulated depreciation as computed consistent with Accounting Requirements.

“Network Integration Transmission Service” shall described in Part III of the TRANSCO Tariff.

“Network Loads” shall have the meaning set forth in Section 1 of the TRANSCO Tariff. The Delivery Points of the Network Loads of Member served pursuant to this Agreement are set forth in Schedule C hereto.

“Network Loss Factor” shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

“Network Resources” shall have the meaning set forth in Section 1 of the TRANSCO Tariff.

“Network Service Agreement” shall mean the Network Service Agreement by and between TRANSCO, AEPCO and the All Requirements Members, substantially in the form attached as Exhibit B-1 to the Member Agreement.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Non-Generation Assets" shall mean as determined in accordance with Accounting Requirements, all assets of AEPCO of every kind, description, and location which shall be acquired by TRANSCO from AEPCO, as of the Closing Date, which are set forth in Schedule 1 to the Restructuring Agreement.

"Non-Pool Loads" shall mean those loads of a Partial Requirements Member or CSP or applicable portions of such loads which are not included in Pooled Loads.

"Non-Pool Resource" shall mean any Resource obtained by a Partial Requirements Member or CSP and which is not included in the Resource Pool.

"O&M" shall mean the general accounting term used to describe activities and expenses involved with the use, operation, maintenance and repair of a cooperative's plant and facilities including expenses associated with activities intended to prevent or remedy an impending or actual breakdown of those facilities. The term O&M does not include the enlargement or improvement of the property owned or leased and operated by a cooperative nor does it include the replacement of retirement units.

"O&M Charge" shall mean the charge computed in accordance with 5.3 of a Partial Requirements Capacity and Energy Agreement which recovers the share of a Partial Requirements Member of certain fixed costs and expenses of AEPCO.

"Off-Peak Hours" shall mean those hours defined by the Western Systems Coordinating Council to represent off-peak load periods, which for each day consist of the eight hours of the hour ending at 2300 through hour ending at 0600, Mountain Standard Time, and the remaining hours of each Sunday and of each of six holidays (New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day).

"Operating Committee" shall mean the standing committee(s) established in the Partial Requirements Capacity and Energy Agreement and assigned by the parties thereto to deal on a prompt and orderly basis with certain technical and operating issues that may arise in connection with system development or operations.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Optional Pool Resources" shall mean those Resources which a party may commit to the Resource Pool.

"Order No. 888" shall mean that certain FERC order Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. para. 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. para. 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC para. 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC para. 61,046 (1998).

"Order No. 889" shall mean that certain FERC order Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs. para. 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & Regs. para. 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC 61,253 (1997).

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period,

as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean, Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Peak Hours" shall mean all hours of each day which are not Off-Peak Hours.

"Performance Default" shall meant the default by either party to a Partial Requirements Capacity and Energy Agreement, a Transmission Agreement, a Network Service Agreement, or a Joint Marketing Agreement, whereby, as provided by the terms of each such Agreement, such party fails to comply, after any notice of such failure and opportunity to cure, with any of the respective terms, conditions, obligations or covenants of such Agreement.

"Person" shall mean an individual, partnership, association, limited liability company, corporation, membership corporation, business trust, joint stock company, trust, cooperative, unincorporated organization, joint venture, or other entity.

"PGR Purchase Agreement" shall mean the Power Purchase Agreement between Panda Gila River, L.P., and AEPCO, dated April 15, 2003, as amended.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Planning Services" shall mean bulk power supply planning and Future Resource procurement services.

"Pool Price" shall mean the price, in mills/kWh, established for a Pooled Resource pursuant to Appendix A-2 of the Resource Pooling Policies.

"Pool Resource Owner" shall mean a Party that has committed Resources to the Resource Pool pursuant to Section 4 herein.

"Pooled Loads" shall mean the aggregate total electric load and sales of the parties that are to be served by Pooled Resources, including distribution losses and not including reserves or transmission losses.

"Pooled Resources" shall mean those Resources which have been committed to the Resource Pool.

"Possible Selling Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Factor" shall mean the cosine of the phase angle between the voltage and the current. Power Factor can be lagging or leading indicating whether the current is lagging or leading the applied voltage.

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

"Power Purchase Resource" shall mean capacity and energy or energy purchased by a party under a contract with a term greater than one year, including any such capacity and energy or energy purchased or acquired pursuant to (i) the Public Utility Regulatory Policies Act of 1978, as it may be amended from time to time, or (ii) the Environmental Portfolio Standard set forth in A.A.C. R14-2-1618, as it may be amended from time to time, as adopted by the Arizona Corporation Commission.

"Power Sale(s)" shall mean a wholesale sale of capacity or energy for a term of one year or more. Power Sales do not include Retail Sales.

"Power Sales Load" shall mean the demand and energy requirements of the load associated with Power Sales Resource(s).

"Power Sales Resource" shall mean a sale of capacity and energy from Existing Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

"Power Sales Resource Demand Revenues" shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Power Sales Resource Energy Revenue" shall mean, for a billing period, the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period

"Power Sales Resource System Facility" shall mean any System Facility or portion thereof that is required to enable delivery of capacity and energy to Class A Members from expired Power Sales Resources which existed as of the Effective Date.

"Pre-Closing" shall mean the execution and delivery of all documents that are a condition to Closing, as further described in the Closing Memorandum.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"Pre-Schedule Day" shall mean the day on which a Pre-Schedule must be submitted for the next Scheduling Day.

"PRM" shall mean a Partial Requirements Member.

"PRM*" shall mean a term in definitions which may be replaced with the name of a PRM so that the definition would apply only to the specified PRM (see Section 3.8 above).

"PRM* 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 (or served from line extensions therefrom) for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement, but shall not include PRM* Wheeling Load. Such demand and energy requirements are included within PRM* Metered kW and PRM* Metered kWh. The demand component of PRM* AEPCO Load numerically consists of the coincident aggregate, at a specific time, of: (i) PRM* Metered kW; less (ii) kW of PRM* Wheeling Load; less (iii) kW of Member JMP Load of PRM*; less (iv) kW of CSP JMP Load of PRM*; (v) less Kw of PRM* Internal Load. The energy component of PRM* AEPCO Load numerically consists of the aggregate during a specific time interval of: (i) PRM* Metered kWh; less (ii) kWh of PRM* Wheeling Load; less (iii) kWh of Member JMP Load of PRM*; less (iv) kWh of CSP JMP Load of PRM*; less, (v) kWh of PRM* Internal Load.

"PRM* 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 PRM* to wholesale buyers or to end use loads which are external to Member's Distribution Service Area of PRM* for which PRM* purchases capacity and energy pursuant to the PRM* Partial Requirements Capacity and Energy Agreement. The demand and energy requirements of PRM* AEPCO Sales shall be metered (or determined) as agreed between PRM* and TRANSCO, on the basis of actual capacity and energy supplied at the applicable points of delivery.

"PRM* External Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located external to the Member's Distribution Service Area of PRM* (and not served from line extensions therefrom) for which PRM* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* External Load are not included in PRM* Metered kW and Member* Metered kWh, respectively.

"PRM* Internal 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 PRM* (or served from line extensions therefrom) for which Member* sells capacity and energy from PRM* Resources. The demand and energy requirements of PRM* Internal Load are included in PRM* Metered kW and PRM* Metered kWh, respectively.

"PRM* Metered kW" shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Metered kWh " shall have the meaning set forth in Section 1 of the PRM* Partial Requirements Capacity and Energy Agreement.

"PRM* Partial Requirements Capacity and Energy Agreement" shall mean the Partial Requirements Capacity and Energy Agreement, by and between AEPCO and PRM*.
"PRM* Resource(s)" shall mean a Resource of a Partial Requirements Member of AEPCO; PRM* Resource does not include the capacity and energy purchased from AEPCO under the PRM* Partial Requirements Capacity and Energy Agreement, or purchased by AEPCO under separate contract.

"PRM* Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and PRM* for the purposes of PRM* Transmission Service.

"PRM* Transmission Service" shall mean Network Integration Transmission Service and all Ancillary Services used to deliver the AC and associated energy of PRM* to PRM* AEPCO Load.

"PRM* Wheeling Load" shall mean the demand and energy requirements, including distribution losses but not including reserves or transmission losses, of loads located within Member's Distribution Service Area of PRM* (or served from line extensions therefrom), which are supplied by capacity and energy from third parties (and not from Member Resources or the AC of PRM*) and for which PRM* provides delivery services over its

distribution system. The demand and energy requirements of PRM* Wheeling Load are included within PR* Metered kW and PRM* Metered kWh, respectively.

"Project Approval" shall mean the approval required by Section 3.4.5 of the Partial Requirements Capacity and Energy Agreement for a Resource Modification.

"Proposal and Analysis" shall have the meaning set forth in Section 3.4.3 of the Partial Requirements Capacity and Energy Agreement.

"Prudent Utility Practice" shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to include a spectrum of possible practices, methods, or acts generally acceptable in the region that could be expected to accomplish the desired result at a reasonable cost consistent with reliability, safety and expedition in light of the circumstances.

"Purchasing Party" shall have the meaning set forth in Section 10.1 of the Resource Integration Agreement.

"Rate Schedule A" shall mean the Schedule A to the Partial Requirements Capacity and Energy Agreements or to an Existing Wholesale Power Contract.

"REAct" shall mean the Rural Electrification Act of 1936.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Receipt Point" shall mean the interconnection between the TTS and the transmission, sub-transmission, generating resource or distribution facilities at which TRANSCO is to accept capacity or energy from AEPCO Resources for delivery pursuant to the Transmission Agreement or Network Service Agreement, and from which TRANSCO provides transmission service to the Delivery Point.

"Reliability System Facilities" shall mean System Facilities and/or improvements that are constructed and installed or acquired by TRANSCO to enhance or maintain the reliability of the TTS as required by the transmission system performance criteria of the NERC, as applied within the WECC, consistent with Prudent Utility Practice.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing

period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Remaining Equity Investment of TRANSCO" shall mean that portion of the installed cost of a System Facility or Direct Assignment Facility financed by an equity contribution of TRANSCO (with interest accrued thereon) which remains undepreciated on the Last Service Date (or the date of closing of a transaction between the parties involving the disposition of a Direct Assignment Facility).

"Remaining Indebtedness of TRANSCO" shall mean the principal balance remaining unamortized as of the Last Service Date (or the Date of Closing of a transaction between the Parties involving the disposition of a Direct Assignment Facility) of that portion of the installed cost of a System Facility or Direct Assignment Facility financed by TRANSCO debt, with interest accrued thereon, which remains unamortized on the Last Service Date or termination or exercise of an option to purchase the Direct Assignment Facilities serving SSVEC (plus any actual prepayment penalties incurred from the prepayment of such debt).

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"Required Modification" shall have the meaning set forth in Section 3.3.2 of the Partial Requirements Capacity and Energy Agreement.
"Resource" shall mean either a Generating Resource or Power Purchase Resource.

"Resource Acquisition" shall mean the performance of analyses of Resource needs or Resource sales proposals, the recommendation of a Power Purchase Resource or Generating Resource, and the negotiation of and acquisition for AEPCO of a Resource.

"Resource Deficiency" shall mean a deficiency in AEPCO Resources available to serve Class A Members and Power Sales Loads.

"Resource Facility" shall mean any System Facility, or portion thereof, or Direct Assignment Facility required to interconnect with and to deliver to the TTS the capacity and energy of any Resource Modification or Future Resource in which SSVEC has all ACP.

"Resource Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending upon the earlier of:(a)the twentieth anniversary thereafter or (b) the last service date of a Class A Member's Wholesale Power Contract, as set forth in the Resource Planning Policies.

"Resource Integration Agreement" shall mean the multi-party agreement by and between CSP, TRANSCO, AEPCO and MEC and dated July 2, 2001, as amended to include SSVEC and TRICO as parties.

"Resource Modification" shall mean any addition, improvement, repair or modification to a Generating Resource or the modification or extension of the term of an existing Power Purchase Resource made by AEPCO which would: (i) increase the capacity of the AEPCO Resource by more than ten percent; or (ii) result in an increase of more than five percent in AEPCO's Revenue Requirement upon the operation of such addition, improvement, repair and modification, or extension, as the case may be, or (iii) require an extension of the term of an Existing Wholesale Power Contract or Partial Requirements Capacity and Energy Agreement. A Resource Modification shall not be construed to include a Minor Resource Modification.

"Resource Operation Policies" shall mean the resource operation policies set forth in Schedule B to the Resource Integration Agreement and Exhibit B2 to Schedule B of the Partial Requirements Capacity and Energy Agreement.

"Resource Planning" shall mean the process used to identify a deficiency in the amount of existing Resources needed to reliably meet anticipated load requirements (including reserves). Resource Planning includes a review of alternative Resources and the selection of the preferred Resources to be constructed or acquired to meet the deficiency.

"Resource Planning Policies" shall mean the resource planning policies set forth in resource planning and acquisition documents.

"Resource Pool" shall mean the capacity and energy pool which integrates the electric capacity and associated energy of AEPCO Resources with Resources owned or contracted for by the Partial Requirements Members and CSP, which the Partial Requirements Member or CSP is required to include or has designated for inclusion in such pool.

"Resource Pool Operation" shall mean that load and resource integration service provided by AEPCO.

"Resource Pooling Policies" shall mean the resource pooling policies set forth in Schedule A of the Resource Integration Agreement.

"Resource Pre-Schedule" shall mean a schedule of energy needed from the Resources of the Resource Pool to meet the aggregate of the Pooled Loads made on a least energy cost and a day-ahead basis.

"Restructuring Agreement" shall mean the Restructuring Agreement as executed and delivered by and among AEPCO, TRANSCO and CSP, dated the 11th day of October 2000.

"Retail Sales" shall mean sales arranged or made by CSP in the competitive retail electric market, including sales at retail from Surplus AEPCO Resources. Retail Sales do not include Power Sales.

"Revenue Shortfall" shall mean the failure of a cooperative to receive sufficient revenue to cover its revenue requirement.

"Rights of Way" shall mean the various rights of way and easements held by TRANSCO from time to time.

"RUS" shall mean the Rural Utilities Service, as successor-in-interest to the Rural Electrification Administration, which is an agency of the United States Department of Agriculture, or any agency of the Government succeeding to its powers and functions

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as a S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduled Day" shall mean the Scheduling Day, as defined by WECC, for which a Pre-Schedule has been submitted.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Scheduling Party" shall mean the owner of an Optional Pool Resource that qualifies to be a Pooled Resource but is not included in the Resource Pool and which is separately scheduled by such owner.

"SEC" shall mean the Securities and Exchange Commission, or any agency of the Government succeeding to its powers and functions.

"Separation of Functions and Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct referenced in Section 15 of the Resource Integration Agreement and set forth as Schedule F attached thereto.

"Service Agreement" shall mean the agreement entered into by a transmission customer or network customer and TRANSCO for transmission service or network service under Part II or Part III respectively, of the TRANSCO Tariff.

"Service Agreement(s) for Firm and Non-Firm Transmission and Ancillary Services" shall mean any Service Agreement by and between TRANSCO and AEPCO for transmission

service pursuant to Part II of the TRANSCO tariff, substantially in the form of agreement attached to the TRANSCO Tariff.

"Short Term" shall mean with respect to a forecast deficiency of AEPCO Resources with respect to AEPCO Total Load, a time period greater than the subsequent two calendar years but lasting less than five calendar years.

"Southwest" shall mean TRANSCO.

"SSVEC" shall mean Sulphur Springs Valley Electric Cooperative, Inc., an electric cooperative non-profit membership corporation organized and existing under the Laws of the State of Arizona.

"Staffing Agreement" shall mean each of the individual staffing agreements whereby CSP shall furnish personnel services to TRANSCO or AEPCO, respectively.

"Standards of Conduct" shall mean the Separation of Functions and Standards of Conduct as set forth as Schedule F to the Resource Integration Agreement.

"Stranded Costs" shall mean any actual charge or cost (including any transmission or distribution surcharges, fee, competition transition charge, wires charge, adjustment, rate, system benefit charge, regulatory charge, regulatory asset surcharge, exit fee or any other mechanism or systematic recovery program approved for use for the recovery of stranded investments) that are permitted by the ACC pursuant to the ACC Electric Competition Rules, A.A.C. R14-2-1601, et seq. or successor rule, or otherwise assessed or levied in order to recover the expenses and liabilities associated with stranded investments including without limitation, regulatory assets, or costs associated with the introduction of competition in the retail sales of electric energy and capacity.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase

"Supplemental Energy Intrachange" shall have the meaning set forth in Section 6 of the Resource Pooling Policies.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made by AEPCO for a period of less than a year to serve load of CARM or a Member* CA Planning Contract Member in excess of CARM's or such Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Surplus AEPCO Resource(s)" shall mean AEPCO Resources available and not necessary or used to serve AEPCO Total Load.

"Surplus Resource" shall mean a Pooled Resource(s) that is surplus to Pooled Load and its operating reserves as determined by a Pool Resource Owner in accordance with Prudent Utility Practice.

"System Facilities" shall mean the transmission lines, substation facilities or components thereof and firm wheeling purchased by TRANSCO, which do not constitute Direct Assignment Facilities and are used to deliver capacity and energy to the Members and other transmission customers of TRANSCO.

"Tag" shall mean the collection of information in the electronic form of request and subsequent response as part of the process implemented by the North American Electric Reliability Corporation for electronically communicating a request for, securing approval of, and recording an energy transaction via the Internet.

"Tariff" shall mean at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sale" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported by AEPCO as an economy sale to RUS Uniform System of Accounts Number 447.

"Times Interest Earned Ratio" or "TIER" " shall mean the financial ratio determined based on figures shown on Form 12 Balance Sheet for each calendar year-end as submitted in accordance with Accounting Requirements by AEPCO or TRANSCO, by: (1) adding (a) net

patronage capital or margins and (b) Interest Expense on long-term Indebtedness, and (2) dividing the sum obtained by Interest Expense on long-term Indebtedness.

"Total Assets" shall mean an amount constituting the total assets of a Class A Member determined in accordance with Accounting Requirements.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

"TRANSCO", which is also known as "Southwest", shall mean Southwest Transmission Cooperative, Inc., a non-profit corporation organized under the Laws of the State of Arizona.

"TRANSCO Assumed AEPCO Debt" shall mean that portion of AEPCO's Indebtedness that TRANSCO assumes pursuant to the TRANSCO CFC Note (if required), the TRANSCO FFB Note(s), the TRANSCO RUS Note(s) and the TRANSCO Assumption and Indemnity Agreements, in each case, in accordance with applicable Law.

"TRANSCO Assumption and Indemnity Agreements" shall mean collectively the Assumption and Indemnity Agreements between TRANSCO and AEPCO and the trustees of certain financial instruments, the forms of which are set forth in Appendix A to the Restructuring Agreement pursuant to which TRANSCO will agree to assume the obligation to pay that portion of AEPCO's debt secured under the AEPCO Mortgage that AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO By-laws" shall mean the By-laws, in the form adopted by the TRANSCO Board of Directors or the TRANSCO Members, as appropriate.

"TRANSCO Employees" shall mean all persons employed by TRANSCO, including TRANSCO Management and systems operations personnel designated by the chief executive officer of TRANSCO, but shall not include persons employed by CSP or any other contractor.

"TRANSCO FFB Note(s)" shall mean the note(s) in the form required by FFB pursuant to which TRANSCO will assume and replace AEPCO as an obligor with respect to that portion of AEPCO's Indebtedness to the FFB outstanding as of the Effective Date that each of

AEPCO and TRANSCO have agreed will be assumed as part of the payment of the purchase price for such assets and liabilities.

"TRANSCO Member" or "Southwest Member" shall mean any of the Class A Members of TRANSCO, and others, including AEPCO and CSP, that become members of TRANSCO in accordance with the TRANSCO By-laws.

"TRANSCO Mortgage" shall mean the Mortgage and Security Agreement, dated as of the Effective Date, made by and among TRANSCO, RUS and CFC which secures the TRANSCO Secured Obligations.

"TRANSCO Notes" shall mean written instruments or notes which evidence the obligation of TRANSCO for its assumption of a portion of the AEPCO Indebtedness (the TRANSCO Assumed AEPCO Debt) to purchase the Transmission Business as evidenced and effected by delivery of the TRANSCO FFB Note(s) and the TRANSCO RUS Note(s), payable to or guaranteed by the Government, acting through the RUS, and by its assumption of the repayment obligations of a portion of the loans made by, or securities issued to, or obligations undertaken to the Financial Entities, and which in the future will also include written instruments which may evidence additional or new loans or advances TRANSCO may obtain to finance the construction or purchase of new facilities for the TTS or the modification of existing TTS facilities, as applicable.

"TRANSCO RUS Note" shall mean the simple allocation of the AEPCO Note owed to RUS.

"TRANSCO Secured Obligations" shall mean collectively, the TRANSCO Notes, certain of the loans made by others to TRANSCO, or securities issued to others by TRANSCO, or debt obligations entitled to the lien created by the TRANSCO Mortgage.

"TRANSCO Tariff" or "Southwest Tariff" shall mean the open access transmission tariff under which transmission services and Ancillary Services are offered by TRANSCO.

"TRANSCO Transmission System" or "TTS" shall mean the electric transmission system of TRANSCO including all transmission lines, substations, microwave and telecommunication facilities, system control and data acquisition system, inventories, works in progress, contract rights to provide or receive transmission services, leases, interests in joint transmission projects, licenses, other related transmission agreements and all other such transmission related assets.

"Transferee" shall mean any of the following Persons: (i) the Person formed as a result of a Member Transaction by any consolidation of the Partial Requirements Member with any other Person; (ii) the survivor of any merger or reorganization of the Partial Requirements Member; (iii) or a Person that acquires or leases all or substantially all of the electric assets of the Partial Requirements Member.

"Transmission Agreement" shall mean the Transmission Agreement by and between TRANSCO and a Partial Requirements Member.

"Transmission Business" shall mean the performance of transmission services and Ancillary Services, and the ownership and use of any rights, obligations, duties, approvals and licenses to the Non-Generation Assets, including the Transmission Resources, and shall include responsibility for the Non-Generation Liabilities.

"Transmission Forecast" shall mean with respect to any Person, such Person's forecast, on an annual basis, of its transmission requirements from TRANSCO.

"Transmission Forecast Period" shall mean the period beginning January 1 of the next calendar year (following the year in which the forecast is prepared) and ending at least the tenth anniversary thereafter.

"Transmission Planning" shall mean the process by which the performance of an electric transmission system is evaluated with respect to specified load-serving capability in accordance with Prudent Utility Practice and by which future modifications, improvements and additions to such electric transmission system are determined by TRANSCO.

"Transmission Requirements Study" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TRICO" shall mean Trico Electric Cooperative, Inc., an electric cooperative non-profit corporation organized and existing under the Laws of the State of Arizona.

"TRS Work Plan" shall have the meaning set forth in Section 4 of the Network Service Agreement.

"TSEPP" shall mean TSE Promotional Products, Inc., an Arizona corporation.

"TTS" shall mean TRANSCO Transmission System.

"WECC" shall mean Western Electricity Coordinating Council, a regional division of NERC, and successor to WSCC.

"Wholesale Power Contract" shall mean a contract, including its amendments and modifications, including the Existing Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement, between AEPCO and a Class A Member of AEPCO, for the wholesale sale by AEPCO of electric power or electric power and transmission services to such Class A Member.

"Withdrawal Agreement" shall mean the form of withdrawal agreement attached to the Member Agreement as Exhibit D.

"WSCC" shall mean Western System Coordinating Council, a regional division of NERC.

ATTACHMENT 2 to First Amendment to Partial Agreement

Partial Requirements Members Rate Schedule A

Partial Requirements Members

RATE SCHEDULE A

Dated May 11, 2010

1. INTRODUCTION:

This Rate Schedule A specifies the rates and charges and the methodology for developing and administering those rates and the charges for capacity and energy sales made by AEPCO to Member pursuant to its 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 charges which are currently in effect in accordance with the Agreement. Exhibit A-2 specifies the methodology for calculating the rates and charges, 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 the methodologies for determining billing units, energy rates and energy charges using cost causation principles. Exhibit A-6 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 Existing Resources, the S&G PPA and Supplemental Purchases (the "Dispatch Pool Resources"). AEPCO may include the Dispatch Pool Resources in a larger pool for dispatch purposes, provided that the Billing Unit Program is maintained pursuant to Exhibit A-4 and the rights and benefits of each Class A Member are not diminished. No additional members may be added to the existing Class A Members with rights in the Dispatch Pool Resources, and changes in the membership shall be subject to Sections 12 and 13 of the Agreement.

AEPCO shall not enter into contracts for or acquire (i) any new AEPCO Generating Resource; or (ii) any AEPCO Power Purchase Resource with a term of greater than one year, unless AEPCO has first entered into a written agreement between AEPCO and all Class A Members agreeing to participate in such Resource, under which no related direct and indirect costs, charges and revenues derived from such Resource would be assigned to any non-participating Class A Members.

2. CONDITIONS OF SERVICE:

2.1 Applicability.

The rates, charges, and adjustments and the methodology for setting and adjusting such rates, charges and adjustments are set forth in this Rate Schedule A. Member shall make payment for electric service under the Agreement through the rates, charges and adjustments established by AEPCO in accordance with the Agreement and this Rate Schedule A. Member shall remain obligated at all times during the term of the 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 Adjustment.

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

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

Where:

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

2.3 Demand Overrun Adjustment.

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

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

Where:

doaf	=	demand overrun adjustment factor
mbdkW	=	Member Schedule in kW or Metered kW less capacity from sources outside the Dispatch Pool, as applicable, and
AC	=	Allocated Capacity of Member, in kW.

2.4 Taxes and/or Assessments.

The rates and charges 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 charges. 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 charges for capacity and energy sales for payment by Member.

2.5 Charges.

The monthly charge billed to 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 as set forth in Exhibit A-1 hereof; plus,

3. the Base Energy Charge and Base Fuel Cost Adjustor Charge, calculated as set forth in Exhibit A-4; plus

4. the Other Energy Charge and Other Fuel Cost Adjustor Charge, calculated as set forth in Exhibit A-4; plus

5. any Power Factor Adjustment pursuant to Section 2.2 hereof; plus,

6. any Demand Overrun Adjustment pursuant to Section 2.3 hereof; plus,

7. all taxes and/or assessments pursuant to Section 2.4 hereof, if any; plus

8. 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 the Agreement, including this Rate Schedule A, is attached to this Rate Schedule A as Exhibit A-6 and made a part hereof. Actual billings made by AEPCO to Member pursuant to Section 5.1 of the 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 charges set forth in Exhibits A-1 to Rate Schedules 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 charges as set forth in Exhibits A-1 to Rate Schedules A and revenues generated from other rates and charges to the Class A Members do not provide revenues sufficient, but only sufficient, to satisfy AEPCO's Revenue Requirements from Class A Members, the Board of Directors of AEPCO shall establish new rates and new charges for electric service to Member pursuant to the procedures set forth in Section 5.6 of the Agreement and otherwise comply with those provisions pertaining to rates and the charges as set forth in Section 5 of the Agreement. Such new rates and charges established in conjunction with new rates and charges for all other Class A Members shall be submitted to the RUS and shall become effective unless they have been disapproved in writing by the RUS, and Exhibits A-1 (and other Exhibits, as may be applicable) to Rate Schedules A shall be modified to reflect such new rates and charges in effect.

3.2 Development of Cost of Service and Revenue Requirement.

AEPCO rates and the charges developed under this Rate Schedule A for charging Member and rates and charges for charging 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 proposed rates and charges based on such cost of service studies and Revenue Requirement are approved by the AEPCO Board of Directors. 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., data shall be 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 all Class A Members shall be developed pursuant 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, or energy as set forth in Exhibit A-2 and depicted in Exhibit A-3 hereto.

3.4 Development of Rates, Charges, and Billing Determinants.

Once the components of fixed, O&M, and energy of AEPCO's Revenue Requirement from All Class A Members are determined pursuant to Section 3.2, and all expenses are classified pursuant to Section 3.3, the rates and charges for electric service pursuant to the Agreement shall be determined in accordance with Exhibit A-2. The billing determinants for Member's Fixed Charge and Member's O&M Charge shall be the ACP as specified in Section 3.5 below. The billing determinants for the energy rates shall be determined pursuant to Exhibit A-4 and as set forth in Section 5.4 of Exhibit A-2.

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 and O&M Charge for Member. Appendix B to Exhibit A-5 to this Rate Schedule A identifies AEPCO Resources in the Dispatch Pool as well as the Allocated Capacity (AC) for Member.

Exhibit A-1 to Rate Schedule A
Partial Requirements Member
Rates and Fixed Charge
(Effective as of Agreement Date)

Fixed Charge	$ per month *
O&M Charge	$ per month *
Energy Rates:	
Base Energy Rate	$_______ per kWh * of base resources used during the billing period.
Other Energy Rate	$_______ per kWh * of other resources used during the billing period.
Power Cost Adjustor Rate for FPPCA:	
Base Resources	$_______ per kWh *
Other Resources	$_______ per kWh *

*based on test year data with pro forma adjustments as approved by the ACC.

Partial Requirements Members
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 charges applicable for AEPCO Resources in which Member has an ACP. This methodology shall be applied to AEPCO expenses and revenues described herein which are maintained under the RUS 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 charges 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 Member through charging the rates and charges developed pursuant to the Agreement, plus (ii) revenues to be recovered from other Partial Requirements Members through rates and charges pursuant to their Partial Requirements Capacity and Energy Agreements; plus (iii) revenues to be recovered from the All Requirements Members through rates and charges pursuant to their Existing Wholesale Power Contracts, plus (iv) 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 RUS 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 under the RUS Uniform System of Accounts by AEPCO 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 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 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 classified as either: (a) Credits-F, (b) Credits-O, or (c) Credits-E.

Margins shall be classified and assigned to the fixed category.

2.2 Depiction.

The expense and revenue accounts and their classification into fixed, O&M and energy 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 charges attributable to electric service under the 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 Charge 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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Account 403	(Depreciation & Amortization Expense),
Account 408	(Ad Valorem Taxes),
Accounts 427-428	(Interest on Long Term Debt, Interest Charged to Construction, 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),
Plus 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 Accts 447-456	(Credits – F) which include: (a) a portion of the revenues from Power Sales Resources, consisting of total Power Sales Resources' revenues less Power Sales Resources' energy revenues, to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such revenues; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services, but excluding the sales of power in subparagraph a above; such portion to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such net revenues.

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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

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), and
Accounts 920-923	(Administrative & General I-O only),
Account 924	(Administrative & General II-O only),
Accounts 925-926	(Administrative & General III-O only), and
Accounts 927-932	(Administrative & General I-O only).
Less Accounts 447-456	(Credits-O) consisting of: (a) Scheduling Revenues - The scheduling revenues resulting from providing scheduling and trading services for customers other than Class A Members of AEPCO, excluding energy-related revenues, to be credited in an amount equal to the product of the total of such revenues multiplied by the ACP of the Member; and (b) a portion as described in footnote 7 of Exhibit A-3 of any other revenues received by AEPCO for any goods or services or other such services; such portion to be credited to Member in an amount equal to the product of its ACP expressed in decimal units multiplied by the amount of such net revenues.

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, to the extent attributable to the AEPCO Resources in which Member has an ACP:

Accounts 501 and 547	(Fuel-E only),
Accounts 555	(Purchased Power-E only),
Account 565	(Wheeling Power-E only),
Accounts 920-923	(Administrative & General I-E only),
Account 924	(Administrative & General II-E only),
Accounts 925-926	(Administrative & General III-E only), and
Accounts 927-932	(Administrative & General I-E only),
Less Accounts 447-456	(Credits-E only).

5.0 MEMBER RATES AND CHARGES:

5.1 Elements.

The rates and charges for electric service under the Agreement to Member shall consist of (a) the Fixed Charge, composed of an appropriate allocated fixed capacity component, including a margin, (b) an O&M Charge, (c) Base Energy Rate, and (d) Other Energy Rate.

5.2 Fixed Charge.

The monthly Fixed Charge for Member, stated in dollars, shall equal: the quotient of (a) the product of (i) 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 caused by failures of Class A Members to meet their portion of AEPCO's Revenue Requirement, multiplied by (ii) the ACP of Member, (b) divided by twelve (12) to convert to a monthly charge.

5.3 O&M Charge.

The O&M Charge for Member shall be equal to the quotient of (a) the product of (i) the annual test year O&M component as calculated in Section 3.3 of this Exhibit A-2, multiplied by (ii) the ACP of Member, (b) divided by twelve (12) to convert to a monthly charge.

5.4 Base Energy Rate and Other Energy Rate.

The Base Energy Rate and Other Energy Rate for Member shall be established based on the methodology contained in Exhibit A-4, and shall together equal the energy component comprised of the expenses, less revenue credits as identified in Section 4.0 of this Exhibit A-2 and calculated pursuant to the methodology in Exhibit A-4, divided by the aggregate test year energy billing units (stated in kWh) developed pursuant to Exhibit A-4 in the cost of service study for the Class A Members, adjusted for known and measurable changes.

6.0 REVENUE SHORTFALLS:

Any deficiencies or shortfalls in collections of AEPCO's Revenue Requirement from Class A Members will be recovered through appropriate adjustments to: (a) the O&M Charge, or (b) the margin included in the Fixed Charge. An adjustment will be made to the O&M Charge 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 Charge 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 charges shall be based on Schedules or on metered data at the Delivery Points. 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 and charges 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.

Partial Requirements Members
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	
	Maintenance:			

[1] All fuel related costs are assigned to the energy classification, except for 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)
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)]
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)]

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[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)
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		
447-456	Operating Revenues from Other Sources – Credit	X(7)	X(7)	X(7)
	Margin Component	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.

[7]Excluding revenue from Power Sales Resources, revenue from sources other than AEPCO's Class A Members shall be credits to the Fixed component and to the O&M component in amounts proportionate to Fixed Revenue Requirements and O&M Revenue Requirements.

Exhibit A-4 to Rate Schedule A
Determination of Billing Units, Energy Rates and Energy Charges Using Cost Causation Principles

1. INTRODUCTION:

This Exhibit A-4 sets forth the methodology for the determination of energy billing units, energy rates and energy charges for each of AEPCO's Class A Members using cost causation allocation principles.

2. DEFINITIONS:

The following terms are used in this Exhibit and its Appendices.

"ARM Energy Cost Responsibility Share" or "ARM ECR" shall mean the percentage share for each billing period of an individual All Requirements Member in CARM S&G PPA Energy Charge, CARM Supplemental Purchase Cost, CARM Base Energy Cost, and CARM Total Other Energy Cost, determined in such billing period as the ratio expressed in percent of each All Requirements Member's Member Billing Energy to CARM Billing Energy.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future

Scheduling Hour; and for each Billing Unit Entity having a percentage interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Base Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Base Fuel Adjustor Cost divided by the Base Billing Energy for the same Billing Unit Entity for the same billing period.

"Base Average Energy Rate" shall mean, for a billing period for each Billing Unit Entity, the rate obtained by dividing the Billing Unit Entity's Base Energy Cost of the billing period by Billing Unit Entity's Base Billing Energy for the same period.

"Base Billing Energy" shall mean, for a Billing Unit Entity, the energy from its Available Base Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Base Schedule or load, accumulated for a billing period.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Economy Purchase Cost" shall mean, for all hours of a billing period, the purchase energy cost incurred by AEPCO for all Base Economy Purchases made in such billing period, including wheeling costs incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any.

"Base Economy Sales" shall mean, for a billing period, the energy from Post-Transfer Excess Base Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Base Economy Sales Cost" shall mean, for each Billing Unit Entity for a billing period, the product of Base Economy Sales multiplied by the Coal Energy Rate.

"Base Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Economy Sales Price, for each of Daytime Hours and Nighttime Hours of a billing period, multiplied by the Billing Unit Entity's Base Economy Sales for Daytime Hours and for Nighttime Hours, respectively, of the same billing period.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the energy from Available Base Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Base Capacity during that billing period.

"Base Energy Mismatch Charge" shall mean, for a billing period, the product of (i) any positive value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Mismatch Credit" shall mean, for a billing period, the product of (i) the absolute value of any negative value of Base Energy Mismatch for the billing period, multiplied by (ii) the Coal Energy Rate for the billing period.

"Base Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Base Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Base FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for the Base Resources for each Billing Unit Entity.

"Base Fuel Adjustor Cost" shall mean for a billing period for each Billing Unit Entity, the sum of the Base Energy Cost, Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Revenues for the same Billing Unit Entity for the same billing period.

"Base Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Base Over or Under Collections.

"Base Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Base Power Cost Adjustor Base, plus (b) Base Power Cost Adjustor Rate, from (ii) Member Base Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Base Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Base Incremental Unit Cost multiplied by (ii) Base Billing Energy, for such Billing Unit Entity for such period.

"Base Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Base Resources as set forth in the Tariff.

"Base Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Base Resources as set forth in the Tariff.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to the Partial Requirements Caacity and Energy Agreements.

"Base Transfer" shall mean, for a Billing Unit Entity, energy from the Billing Unit Entity's Excess Base Capacity that has been assigned and allocated to the load or Other Schedule of other Billing Unit Entities in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess Base Capacity of other Billing Unit Entities that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Base Transfer Energy Cost" shall mean, for each Billing Unit Entity for a billing period, Coal Energy Rate multiplied by Base Transfer.

"Base Transfer Purchase Cost" shall mean, for each Billing Unit Entity that has been assigned Base Transfer Billing Energy, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of its Base Transfer Billing Energy, multiplied by the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable.

"Base Transfer Sales Credit" shall mean, for each Billing Unit Entity, for each of separately accumulated Daytime Hours and Nighttime Hours of a billing period, the product of (i) the Economy Purchase Rate of Daytime Hours or Nighttime Hours, as applicable, multiplied by (ii) its Base Transfer of Daytime Hours or Nighttime Hours, as applicable.

"Base Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Base Resources, for the same billing period, multiplied by its (ii) the Billing Unit Entity's ACP in Existing Resources.

"Billing Energy" shall mean the energy of each billing period determined pursuant to the Billing Unit Program to have served the entirety of the Schedule of each Member*, or the

entirety of the load of CARM or the entirety of the Directed Sales and load of a Member* CA in such billing period, consisting of the sum of the Billing Unit Entity's Base Billing Energy, S&G PPA Billing Energy, Other Billing Energy, Base Transfer Billing Energy, Supplemental Billing Energy, and S&G And Supplemental Transfer Billing Energy.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"Billing Unit Program" shall mean the software program and subroutines that are used by AEPCO's Power Trading and Scheduling Department for the purpose of determining monthly each Billing Unit Entity's Billing Energy from Base Resources, Other Resources, S&G PPA and Supplemental Purchase by hourly allocation and assignment of energy from Available Base Capacity, Available Other Capacity, Available S&G PPA Capacity and Available Supplemental Capacity to each of (i) the loads of the CARM; (ii) the Directed Sales and load of a Member* CA; (iii) the Schedules; (iv) Base Transfers; (v) S&G And Supplemental Transfers; and (vi) Third Party Economy Sales.

"CARM" or "Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources and in S&G PPA, as applicable to each All Requirements Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A to the ARM Wholesale Power Contracts.

"Coal Energy Cost" shall mean, for a billing period, the accumulated costs of coal and natural gas expensed during that billing period, related to the operation and dispatch during that billing period of two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 501 or its successor for that billing period.

"Coal Energy Rate" shall mean, for a billing period, Coal Energy Cost divided by the product of Coal Energy Generated multiplied by the difference obtained by subtracting the Network Loss Factor from one (1).

"Coal Energy Generated" shall mean, for a billing period, the net energy output at the 230 kv bus of the two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station.

"Daytime Hours" shall mean the 16 hours of each day beginning Hour Ending 0700 through Hour Ending 2200 Pacific Prevailing Time, including Sundays and Holidays.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AC in AEPCO Resources.
"Directed Sales Credit" shall mean the revenue realized from Directed Sales.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"Economy Purchase Cost" shall mean, separately accumulated for Daytime Hours and Nighttime Hours of a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of the billing period.

"Economy Purchase Rate" shall mean, separately calculated for Daytime Hours and Nighttime Hours of a billing period, the rate obtained by dividing Economy Purchase Cost of Daytime Hours or Nighttime Hours of that billing period, by energy received from Non-Base Economy Purchases and Replacement Purchases in effect in such Daytime Hours or Nighttime Hours of that billing period.

"Economy Sales Price" shall mean, for Third Party Economy Sales, for each of Daytime Hours and Nighttime Hours, the quotient obtained by dividing (i) the numerator equal to the sum of the revenue from all Third Party Economy Sales during the billing period in Daytime Hours and Nighttime Hours, respectively, reduced by any payments to SWTC or third parties for transmission used in delivery of such sales, by (ii) a denominator equal to the MWh of energy delivered as Third Party Economy Sales during such hours.

"Energy Cost Accounting Process" or "ECAP" shall mean the software program and subroutines that are used by AEPCO's Financial Services Department for the purpose of determining monthly each Billing Unit Entity's costs for energy from Base Resources, Other Resources, S&G PPA, and Supplemental Resources.

"Excess Base Capacity" shall mean, for a billing period for each Billing Unit Entity, the separately accumulated Daytime and Nighttime billing period totals of Available Base Capacity that is not assigned in an hour pursuant to the Billing Unit Program as Base Billing Energy.

"Excess S&G And Supplemental Capacity" shall mean, for a billing period for each Billing Unit Entity having an ACP interest in S&G PPA and/or Supplemental Purchase, Available S&G PPA Capacity and/or Available Supplemental Capacity, that is not assigned in an hour pursuant to the Billing Unit Program as S&G PPA Billing Energy and Supplemental Billing Energy.

"Federal Hydro Power Agreement(s)" shall mean 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 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).

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Gas Energy Cost" shall mean, for a billing period, the accumulated costs of natural gas expensed during that billing period, related to the operation and dispatch during that billing period of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station, as recorded in RUS Uniform System of Accounts 547 or its successor for that billing period.

"Gas Energy Generated" shall mean, for a billing period, the net energy output at the applicable bus of the gas-fired Generating Resources that are Existing Resources located at the Apache Generating Station.

"Gas Energy Rate" shall mean, for a billing period, Gas Energy Cost divided by the product of Gas Energy Generated.

"Hydro Demand Charge" shall mean, for a billing period, demand charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Hydro Energy Charge" shall mean, for a billing period, energy charges associated with Federal Hydro Power Agreements as recorded in RUS Uniform System of Accounts 555 or its successor for the billing period.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Network Loss Factor" shall mean the adjustment factor for transmission losses assigned for network service under the Southwest Transmission Cooperative, Inc. Open Access Transmission Tariff as in effect from time to time.

"Nighttime Hours" shall mean the eight (8) hours beginning Hour Ending 2300 of one day continuing through Hour Ending 0600 of the following day, Pacific Prevailing Time.

"Non-Base Economy Purchase" shall mean any purchase of energy by AEPCO from a third party that is not a Base Economy Purchase which is made at a lower average energy rate over the purchase period than that which would be associated with energy dispatched from Available Other Capacity or Available S&G PPA Capacity during such period, and which is made in lieu of dispatching energy from such capacity.

"Operating Reserve Purchases" shall mean any purchases of operating reserve capacity to avoid curtailing any energy from any more economical AEPCO Resource that would otherwise be required to provide such operating reserve capacity.

"Other Adjustor Per Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the Other Fuel Adjustor Cost divided by the Total Other Billing Energy for the same Billing Unit Entity for the same billing period.

"Other Average Energy Rate" shall mean, for a billing period for a Billing Unit Entity, the rate obtained by dividing its Total Other Energy Cost of the billing period by its Other Billing Energy for the same period.

"Other Billing Energy" shall mean, for a Billing Unit Entity, the energy from Available Other Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its Other Schedule or load, accumulated for a billing period.

"Other Economy Sales" shall mean, for a billing period, the energy from dispatched Other Capacity and from Post-Transfer S&G And Supplemental Capacity assigned in each hour to each Billing Unit Entity pursuant to the Billing Unit Program as Third Party Economy Sales.

"Other Economy Sales Credit" shall mean, for each Billing Unit Entity, the product of the Other Economy Energy Sales Revenue of Daytime Hours and Nighttime Hours, as applicable, multiplied by the ratio of (i) for each of separately accumulated Daytime Hours and Nighttime Hours of the billing period, the Post-Transfer S&G And Supplemental Capacity energy in the case of a Billing Unit Entity with an ACP in such capacity, the Other Schedule in the case of a Member*, and in the case of CARM or a Member* CA, its load's use of Available Other Capacity, to (ii) the total of such Post-Transfer S&G And Supplemental Capacity, such Other Schedules and such uses of Available Other Capacity by all Billing Unit Entities for the same time periods.

"Other Economy Sales Revenue" shall mean the difference obtained by subtracting the Base Economy Sales Credit from the revenue of all Third Party Economy Sales during a billing period.

"Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the costs of purchased energy and natural gas fuel and oil fuel expensed during that billing period, related to the operation and dispatch of Available Other Capacity during that billing period, as recorded in Accounts described in Section 4.0 of Exhibit A-2 to Rate Schedule A and reported to RUS by AEPCO for that billing period, including purchased energy expenses, wheeling charges and costs of any transmission losses related to Other Economy Purchases and Replacement Purchases for Base Resources and Other Resources as incurred during that billing period.

"Other Energy Mismatch" shall mean, for a billing period, the accumulated net difference in energy obtained from subtracting (i) the total energy from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity assigned and allocated in the billing period in accordance with the Billing Unit Program, from (ii) the energy actually produced from Available Other Capacity, Available Supplemental Capacity, and Available S&G PPA Capacity during that billing period.

"Other Energy Mismatch Credit" shall mean, for a billing period, the product of: (i) the absolute value of any negative value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Mismatch Charge" shall mean, for a billing period, the product of: (i) any positive value of Other Energy Mismatch for the billing period, multiplied by (ii) the Gas Energy Rate for the billing period.

"Other Energy Rate" shall mean, for each Billing Unit Entity, the rate applicable to that Billing Unit Entity's use of energy from Available Other Capacity as set forth in Exhibit A-1 to Rate Schedule A.

"Other FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for a FPPCA Period for Other Resources, Supplemental Purchase as made for each Billing Unit Entity, and S&G PPA for each Billing Unit Entity having an ACP interest in S&G PPA.

"Other Fuel Adjustor Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of the Total Other Energy Cost, Other Transmission Wheeling Cost, plus, for those Billing Unit Entities with interests in S&G PPA Capacity or Supplemental Capacity, Supplemental Demand Charge, Supplemental Wheeling Cost, S&G PPA Purchase Demand Charge and S&G PPA Wheeling Cost.

"Other Fuel Bank" shall mean, for a billing period for each Billing Unit Entity, the accumulation of Other Over or Under Collections.

"Other Incremental Unit Cost" shall mean, for a billing period for each Billing Unit Entity, the difference obtained by subtracting (i) the sum of (a) Other Power Cost Adjustor Base plus (b) Other Power Cost Adjustor Rate from (ii) Other Adjustor Per Unit Cost, for such Billing Unit Entity for such period.

"Other Over or Under Collection" shall mean, for a billing period for each Billing Unit Entity, the product of (i) Other Incremental Unit Cost, multiplied by (ii) Total Other Billing Energy, for such Billing Unit Entity for such period.

"Other Power Cost Adjustor Base" shall mean the Power Cost Adjustor Base for Other Resources as set forth in the Tariff.

"Other Power Cost Adjustor Rate" shall mean the Power Cost Adjustor Rate for Other Resources as set forth in the Tariff.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with Schedule B to its Partial Requirements Capacity and Energy Agreement.

"Other Transmission Wheeling Cost" shall mean, for each Billing Unit Entity for a billing period, the product of (i) the costs recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor, and allocated to Other Resources, for the same billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Planning Contract Member" shall mean a Partial Requirements Member which has contracted separately from the Partial Requirements Capacity and Energy Agreement to obtain Planning Services from AEPCO.

"Post-Base Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Load to that Billing Unit Entity's Available Base Capacity.

"Post-Base Other Schedule" shall mean, for a Member*, the portion of the Total Schedule of such Member* that remains after assignment of such Member*'s Base Schedule to that Member*'s Available Base Capacity.

"Post-Base Transfer Load" shall mean, for CARM or a Member* CA, any load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-S&G And Supplemental Transfer Load to Base Transfers of other Billing Unit Entities.

"Post-Base Transfer Other Schedule" shall mean, for Member*, any Post-S&G And Supplemental Other Schedule that remains after assignment of such Member*'s Post S&G And Supplemental Transfer Other Schedule to Base Transfers from other Billing Unit Entities.

"Post-Sales Base Capacity" shall mean, for each Billing Unit Entity, any Post Transfer Base Capacity that remains after its allocation to Base Economy Sales.

"Post-S&G And Supplemental Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's load to that Billing Unit Entity's allocated share of S&G PPA Capacity and Supplemental Capacity.

"Post-S&G And Supplemental Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of S&G And Supplemental Transfers from another Billing Unit Entity to that Billing Unit Entity's Post-Base Load.

"Post-S&G And Supplemental Transfer Other Schedule" shall mean, for Member*, the Post-Base Other Schedule that remains after allocation of S&G And Supplemental Transfers from CARM or a Member* CA.

"Post-Transfer Base Capacity" shall mean, for a Billing Unit Entity, each hour's Excess Base Capacity remaining after energy from its Excess Base Capacity has been assigned as Base Transfers.

"Post-Transfer Load" shall mean, for CARM or a Member* CA, the load of such Billing Unit Entity that remains after assignment of such Billing Unit Entity's Post-Base Load to that Billing Unit Entity's allocated share of S&G And Supplemental Transfers and of Base Transfers from other Billing Unit Entities.

"Post-Transfer Other Schedule" shall mean, for a Member*, the Total Schedule of such Member* that remains after assignment of such Member*'s allocated share of S&G And Supplemental Transfers from other Billing Unit Entities to its Post-Base Other Schedule, and then assignment of such Member*s allocated share of Base Transfers from other Billing Unit Entities to that Member*'s Post-S&G And Supplemental Transfer Other Schedule.

"Post-Transfer S&G And Supplemental Capacity" shall mean, for CARM or Member* CA having an ACP in S&G PPA and/or an interest in Supplemental Purchase, each hour's Excess S&G And Supplemental Capacity remaining after energy from its Excess S&G And Supplemental Capacity has been assigned as an S&G And Supplemental Transfer, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"Power Sales Resource Demand Revenues" shall mean, for a billing period for each Billing Unit Entity, the product of (i) the demand-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale, or its successor, for that billing period, multiplied by (ii) the Billing Unit Entity's ACP in Existing Resources.

"Power Sales Resource Energy Revenue" shall mean, for a billing period the energy-related revenue received pursuant to Power Sales Resource contracts as recorded in RUS Uniform System of Account 447 Sales for Resale or its successor, for that billing period.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"PRM" shall mean a Partial Requirement Member.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Remaining Base Energy Cost" shall mean, for a billing period, the total of Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchase Cost and Power Sales Resource Energy Revenue, for the same billing period as allocated to each Billing Unit Entity based on the ratio of (i) the Billing Unit Entity's Base Billing Energy for that billing period to (ii) the total of all Billing Unit Entities' Base Billing Energy for the same billing period.

"Remaining Coal Energy Cost" shall mean, for a billing period, Coal Energy Cost for the billing period less the sum of Base Transfer Sales Credits and Base Economy Sales Credits for all Billing Unit Entities for the same billing period.

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"S&G And Supplemental Sales Credit" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA or an interest in Supplemental Purchase, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer, for such Billing Unit Entity for such billing period.

"S&G And Supplemental Transfer" shall mean, for a Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase, energy from its Excess S&G And Supplemental Capacity that has been assigned and allocated to another Billing Unit Entity in an hour pursuant to the Billing Unit Program, accumulated for a billing period separately for Daytime Hours and Nighttime Hours.

"S&G And Supplemental Transfer Billing Energy" shall mean, for a Billing Unit Entity, energy from the Excess S&G And Supplemental Capacity of another Billing Unit Entity with an ACP in S&G PPA and/or an interest in Supplemental Purchase that has been assigned and allocated to the Billing Unit Entity in an hour pursuant to the Billing Unit Program as an S&G And Supplemental Transfer from the other Billing Unit Entity, accumulated for a billing period.

"S&G And Supplemental Transfer Purchase Cost" shall mean, for a billing period for each Billing Unit Entity that is assigned an S&G And Supplemental Transfer pursuant to the Billing Unit Program, the product of the Economy Purchase Rate multiplied by S&G And Supplemental Transfer Billing Energy, for such Billing Unit Entity for such billing period.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an ACP in S&G PPA, the energy from its Available S&G PPA Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its S&G PPA Transfers, accumulated for a billing period.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for capacity from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the total cost incurred by AEPCO for all energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"S&G PPA Schedule" shall mean, for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"S&G PPA Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an ACP in S&G PPA, the product of (i) the cost incurred by AEPCO for wheeling energy from S&G PPA during the billing period multiplied by (ii) the Billing Unit Entity's ACP in S&G PPA.

"Schedule" shall mean, for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real-Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Supplemental Billing Energy" shall mean, for a billing period for a Billing Unit Entity with an interest in Supplemental Purchase, the energy from its Available Supplemental Capacity assigned and allocated in each hour pursuant to the Billing Unit Program to its load and its Supplemental Transfers, accumulated for a billing period.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Demand Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for capacity from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Supplemental Energy Charge" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the total cost incurred by AEPCO for all energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in the Supplemental Purchase.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made for a period of less than a year to serve load of CARM or a Planning Contract Member in excess of CARM's or the Planning Contract Member's ACP shares of capacity of S&G PPA and Existing Resources.

"Supplemental Purchase Cost" shall mean, for a billing period, the total cost incurred by AEPCO (including transmission expenses, including losses, incurred in delivery from the source of such purchase to an SWTC Point of Receipt, if any) for all Supplemental Purchases during the billing period.

"Supplemental Wheeling Cost" shall mean, for a billing period for each Billing Unit Entity with an interest in Supplemental Purchase, the product of (i) the cost incurred by

AEPCO for wheeling energy from Supplemental Purchase during the billing period multiplied by (ii) the Billing Unit Entity's ACP in Supplemental Purchase.

"Tariff" shall mean, at any time, the currently effective form setting forth the various AEPCO rates and charges applicable to each Billing Unit Entity as approved by the ACC.

"Third Party Economy Sales" shall mean, for each of Daytime Hours and Nighttime Hours, any transactions in which AEPCO sells at wholesale energy from available AEPCO Resources to a third party, which transaction is not a Power Sales Resource, and which is recorded and reported as an economy sale by AEPCO to RUS Uniform System of Accounts Number 447.

"Total Other Billing Energy" shall mean, for a billing period for each Billing Unit Entity, the sum of S&G And Supplemental Transfer Billing Energy, S&G PPA Billing Energy, Supplemental Billing Energy, Other Billing Energy and Base Transfer Billing Energy for such Billing Unit Entity for such billing period.

"Total Other Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Other Energy Cost, S&G PPA Energy Charge, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Sales Credit, Directed Sales Credit, Base Transfer Purchase Cost, and Other Economy Sales Credit.

"Total Schedule" shall mean, for each Member*, its Base Schedule, plus its Other Schedule, plus, if applicable, its S&G PPA Schedule.

3. <u>BILLING UNIT PROGRAM METHODOLOGY</u>:

The Billing Unit Program shall be assembled and maintained to reflect AEPCO's economic dispatch philosophy and priority as further set forth in Schedule B to the Partial Requirements Capacity and Energy Agreements. The Parties have divided and defined AEPCO Resources based on the respective interests therein as assigned under the Billing Unit Program, the definition of which is set forth in Appendix A to this Exhibit A-4, attached hereto and a part hereof.

The Billing Unit Program is established hereunder to account for hourly energy, separately for Daytime and Nighttime hours, first, for each Billing Unit Entity, its Minimum Other Capacity, then for each Billing Unit Entity having an ACP in S&G PPA or an interest in Supplemental Purchase, from its interests in Available Supplemental Capacity and Available S&G PPA Capacity (as dispatched by AEPCO under governing purchase contracts), then for each Billing Unit Entity its Available Base Capacity and finally its remaining Available Other Capacity. These hourly amounts for each Billing Unit Entity are assigned first to any Directed Sales of a Member* CA, to the loads of the CARM and Member* CA and to each Member*'s Total Schedule, but only to the extent required by the load of the CARM, by the Directed Sales and load of the Member* CA and by the Member*'s Total Schedule.

If a Billing Unit Entity has load or a Schedule that is not satisfied by its Available Base Capacity, Available Supplemental Capacity and Available S&G PPA Capacity, the Billing Unit Entity shall be assigned S&G And Supplemental Transfers and Base Transfers from other Billing Unit Entities' Excess S&G And Supplemental Capacity and Excess Base Capacity pursuant to the Billing Unit Program, proportionately based on the need of each Billing Unit Entity for Other Resources to the need of all Billing Unit Entities for Other Resources. To the extent a Billing Unit Entity still has load or a Schedule that is not satisfied, energy shall be assigned to it from its Available Other Capacity.

On the other hand, if a Billing Unit Entity has any Excess S&G And Supplemental Capacity or Excess Base Capacity, it shall be assigned pursuant to the Billing Unit Program proportionately based on available excess as S&G And Supplemental Transfers and Base Transfers. Then any Post-Transfer Base Capacity shall be assigned pursuant to the Billing Unit Program proportionately based on the amounts of such excess in the hour as Base Economy Sales, if any, or shall be assigned as Base Energy Mismatch or Other Energy Mismatch, as applicable.

Finally pursuant to the Billing Unit Program, the Other Economy Sales accumulated for the billing period will be allocated to each Billing Unit Entity proportionately based on each Billing Unit Entity's proportionate share of the billing period's accumulated totals of Post-Transfer S&G And Supplemental Capacity, each Member*'s Other Billing Energy, CARM Other Billing Energy, and each Member* CA's Other Billing Energy.

The Parties agree that all such assignments and allocations represent sale and purchase transactions to and from the Dispatch Pool Resources for which each Billing Unit Entity shall be credited or billed pursuant to Section 4 below.

Base Energy Mismatch and Other Energy Mismatch may occur due to operating conditions experienced during any billing period when the assignment and allocation of energy pursuant to the Billing Unit Program may be more or less than the amount of energy actually produced by the Dispatch Pool Resources; the causes of which may include, but are not limited to: (i) energy received from resources of third parties or provided to third parties for losses repayment; (ii) variations between loss accounting and actual hourly losses occurring on the system; (iii) energy interchange with other utilities; (iv) metering errors; and (v) inadvertent flows between AEPCO and its Balancing Authority. The Billing Unit Program shall compute for each billing period the total net Base Energy Mismatch and total Other Energy Mismatch and assign a credit or charge for the period, as applicable, which shall be recovered through the appropriate FPPCA.

The initial logic flow diagram of the Billing Unit Program is attached hereto as Appendices B through D to this Exhibit A-4 and is a part hereof. The Billing Unit Program shall be the sole and exclusive method for billing purposes of assigning energy billing units from Dispatch Pool Resources to Billing Unit Entities, and may only be modified by a written amendment agreed to by the CEOs of all Billing Unit Entities.

4. METHODOLOGY FOR DETERMINING TARIFF ENERGY RATES:

The following describes the method AEPCO shall use to formulate the Base Energy Rate and the Other Energy Rate.

4.1 Tariff Base Energy Rate.

The Base Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Base Energy Cost of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's Base Transfer Sales Credits, Base Transfer Energy Cost, Base Economy Sales Credits, Base Economy Sales Cost and Remaining Base Energy Cost, by (ii) each Billing Unit Entity's Base Billing Energy of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.1.1 The Base Energy Rate of each All Requirements Member shall be the same as the Base Energy Rate for CARM.

4.1.2 The Base Power Cost Adjustor Base for each All Requirements Member shall be the same as the Base Power Cost Adjustor Base determined for CARM.

4.1.3 The Base Billing Energy of each All Requirements Member shall be the product of (i) the Base Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

4.2 Tariff Other Energy Rate.

The Other Energy Rate of the Tariff shall be the quotient obtained by dividing (i) the Total Other Energy Cost of each Billing Unit Entity of the test period, as adjusted for changes expected in the foreseeable period beyond the test period, inclusive of each Billing Unit Entity's applicable Base Transfer Purchase Cost, S&G PPA Energy Cost, Supplemental Purchase Cost, S&G And Supplemental Transfer Purchase Cost, S&G And Supplemental Transfer Sales Credit, Other Economy Sales Credit and its share of Base Mismatch Energy Credit, Base Mismatch Energy Charge, Other Mismatch Energy Credit, Other Mismatch Energy Charge and, if any, by (ii) the Total Other Billing Energy as applicable to each Billing Unit Entity for the test period, as adjusted for changes expected in the foreseeable period beyond the test period, as determined pursuant to the Billing Unit Program.

4.2.1 The Other Energy Rate of each All Requirements Member shall be the same as the Other Energy Rate for CARM.

4.2.2 The Other Power Cost Adjustor Base for each All Requirements Member shall be the same as the Other Power Cost Adjustor Base determined for CARM.

4.2.3 The Total Other Billing Energy of each All Requirements Member shall be the product of (i) the Total Other Billing Energy of CARM, multiplied by (ii) that All Requirements Member's ARM ECR.

5. DETERMINING BASE AND OTHER ENERGY CHARGES:

5.1 Each billing period, AEPCO shall charge each Billing Unit Entity a Base Energy Charge, Base Fuel Adjustor Charge, Total Other Energy Charge and Other Fuel Adjustor Charge as defined in the Tariff. For each billing period, AEPCO shall compute each Billing Unit Entity's Base Over or Under Collection and Other Over or Under Collection for each billing period, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

5.1.1 Base Energy Charge: The Base Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Energy Rate as set forth in the Tariff.

5.1.2 Base Fuel Adjustor Charge: The Base Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Base Billing Energy of the Billing Unit Entity, multiplied by the Base Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.3 Base Over or Under Collection: The Base Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Base Adjustor Per Unit Cost and (ii) the sum of the Base Power Cost Adjustor Base plus the Base Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Base Billing Energy of each Billing Unit Entity for that period.

5.1.4 Other Energy Charge: The Other Energy Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Energy Rate as set forth in the Tariff.

5.1.5 Other Fuel Adjustor Charge: The Other Fuel Adjustor Charge for each Billing Unit Entity for a billing period shall equal the product of the Total Other Billing Energy of the Billing Unit Entity, multiplied by the Other Fuel Power Cost Adjustor Rate as set forth in the Tariff.

5.1.6 Other Over or Under Collection: The Other Over and Under Collection for each Billing Unit Entity for a billing period shall be determined pursuant to the methodology approved by the ACC related to the product of (a) any difference between (i) the Other Adjustor Per Unit Cost and (ii) the sum of the Other Power Cost Adjustor Base plus the Other Power Cost Adjustor Rate in the Tariff, multiplied by (b) the Total Other Billing Energy of each Billing Unit Entity for that period.

6. ENERGY COST ACCOUNTING PROCESS:

The following describes the method of the Energy Cost Accounting Process (ECAP) AEPCO shall use to formulate for each billing period each Billing Unit Entity's Base Energy Cost, Base Fuel Adjustor Cost, Total Other Energy Cost and Other Fuel Adjustor Cost, from which AEPCO shall compute each Billing Unit Entity's Base Adjustor Per Unit Cost and Other Adjustor Per Unit Cost for the billing period, which shall be used to calculate for each billing period (i) Base Over and Under Collection and Other Over or Under Collection for such energy and (ii) fuel adjustor costs, which AEPCO shall accumulate and use to establish future Base Fuel Adjustor Rates and Other Fuel Adjustor Rates.

The initial logic flow diagram of the ECAP is attached hereto as Appendices E and F to this Exhibit A-4 and is a part hereof.

6.1 Formulating Base Energy Cost.

For each billing period, the ECAP shall first compute the Coal Energy Cost and use it to calculate the Coal Energy Rate based on the Coal Energy Generated.

The ECAP shall then use Base Transfer for the billing period to compute, separately for Daytime and Nighttime, Base Transfer Sales Credit based on the Coal Energy Rate, and use Base Transfer Billing Energy to compute, separately for Daytime and Nighttime, Base Transfer Energy Cost, based on the Economy Purchase Rate. Using the billing units determined for the billing period pursuant to the Billing Unit Program, the Base Transfer Sales Credits and Base Transfer Energy Cost will then be allocated to each Billing Unit Entity. Similarly, the ECAP shall use Base Economy Sales for the billing period to compute Base Economy Sales Credits (separately for Daytime and Nighttime) and Base Economy Sales Cost, based on Economy Sales Price (separately for Daytime and Nighttime) and the Coal Energy rate, respectively, and shall then allocate such Base Economy Sales Credits and Base Economy Sales Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall then calculate Base Billing Energy Cost for the billing period, by adding Remaining Coal Energy Cost, Hydro Energy Charge, Base Economy Purchases and Power Sales Resource Energy Revenue, and shall allocate such

Base Billing Energy Cost to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

Finally, the ECAP shall calculate for the billing period each Billing Unit Entity's (i) Base Energy Cost, which shall be the total of the Billing Unit Entity's Base Transfer Sales Credit, Base Transfer Energy Cost, Base Economy Sales Credit, Base Economy Sales Cost and Remaining Base Energy Cost, and (ii) Base Average Energy Rate, which shall be the quotient of the Billing Unit Entity's Base Energy Cost divided by its Base Billing Energy determined pursuant to the billing units assigned by the Billing Unit Program.

6.2 Formulating Base Adjustor Per Unit Cost.

The ECAP shall allocate to each Billing Unit Entity based on the Billing Unit Entity's Allocated Capacity Percentage the billing period's total Hydro Demand Charge, Base Transmission Wheeling Cost and Power Sales Resource Demand Cost, which allocation ECAP shall add to the Billing Unit Entity's Base Energy Cost to formulate the Billing Unit Entity's Base Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Base Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Base Fuel Adjustor Cost divided by its Base Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.3 Formulating Base Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Base Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Base Adjustor Per Unit Cost less the sum of (i) its Base Power Cost Adjustor Base and (ii) its Base Power Cost Adjustor Rate, and (b) Base Over or Under Collection, which shall be the product of the Billing Unit Entity's Base Incremental Unit Cost multiplied by its Base Billing Energy. Each Billing Unit Entity's Base Over or Under Collection shall then be added to the balance in its Base Fuel Bank.

6.4 Formulating Total Other Energy Cost.

Each billing period, the ECAP shall use the Economy Purchase Rate (separately for Daytime and Nighttime) to determine S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit based on S&G And Supplemental Transfer. Such S&G And Supplemental Purchase Cost and S&G And Supplemental Sales Credit shall then be allocated as appropriate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program.

The ECAP shall allocate to each Billing Unit Entity pursuant to the billing units assigned by the Billing Unit Program (i) the billing period's Other Economy Sales

Credit as appropriate based on the Billing Unit Entity's proportionate share of the billing period's Post-Transfer S&G And Supplemental Capacity and Other Billing Energy, and (ii) the billing period's Other Energy Cost based on the Billing Unit Entity's Other Billing Energy. The ECAP shall then assign to each Billing Unit Entity pursuant to the Billing Unit Entity's ACP and/or interest in and the billing units assigned by the Billing Unit Program, as applicable, the Billing Unit Entity's S&G PPA Energy Charge, Supplemental Energy Charge, Base Transfer Purchase Cost, Other Energy Cost, Directed Sales Credit, and its share of Base Mismatch Energy Credit, Base Mismatch Energy Cost, and Other Mismatch Energy Credit.

Finally, the ECAP shall determine for the billing period (i) each Billing Unit Entity's Total Other Energy Cost, which shall be equal to the sum of all the credits and costs allocated or assigned to the Billing Unit Entity as described in this Section 6.4, and (ii) each Billing Entity's Other Average Energy Rate, which shall be the quotient of its Total Other Energy Cost divided by its Total Other Billing Energy.

6.5 Formulating Other Adjustor Per Unit Cost.

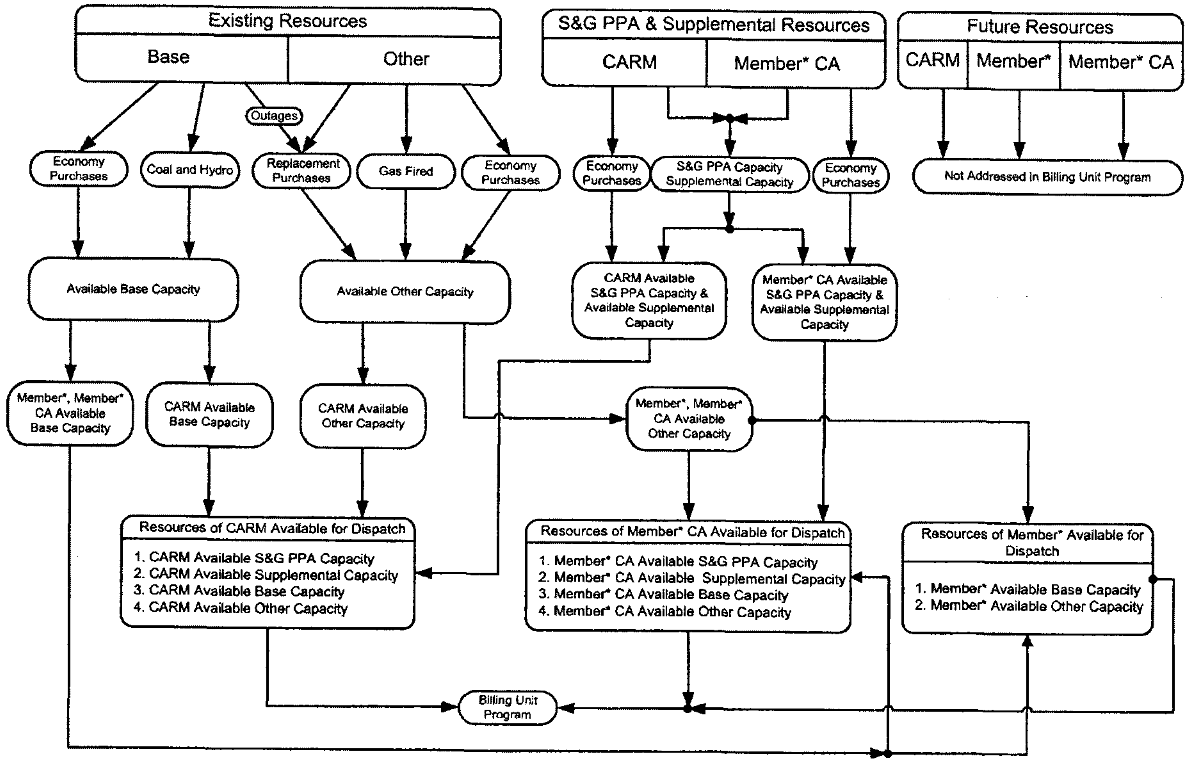
The ECAP shall allocate to each Billing Unit Entity the billing period's (i) total Other Transmission Wheeling Cost based on the Billing Unit Entity's Allocated Capacity Percentage, and (ii) S&G PPA Demand Charge, S&G PPA Wheeling Cost, Supplemental Demand Charge and Supplemental Wheeling Charge, pursuant to the Billing Unit Entity's ACP share or interest therein, if any. The ECAP shall then add such allocations to each Billing Unit Entity's Total Other Energy Cost to formulate the Billing Unit Entity's Other Fuel Adjustor Cost.

The ECAP shall then determine each Billing Unit Entity's Other Adjustor Per Unit Cost for the billing period, which shall be the quotient of the Billing Unit Entity's Other Fuel Adjustor Cost divided by its Total Other Billing Energy pursuant to the billing units assigned by the Billing Unit Program.

6.6 Formulating Other Over or Under Collection.

The ECAP shall then determine for the billing period each Billing Unit Entity's (a) Other Incremental Unit Cost, which shall be equal to the Billing Unit Entity's Other Adjustor Per Unit Cost less the sum of (i) its Other Power Cost Adjustor Base, plus (ii) its Other Power Cost Adjustor Rate, and (b) Other Over or Under Collection, which shall be the product of the Billing Unit Entity's Other Incremental Unit Cost multiplied by its Other Billing Energy. Each Billing Unit Entity's Other Over or Under Collection shall then be added to the balance in its Other Fuel Bank.

Appendix A to Exhibit A-4 to Rate Schedule A: AEPCO Resources Definitions Flow Diagram



Appendix B Footnotes:

(1) Subroutine: CARM Post S&G And Supplemental Load is first assigned to CARM Minimum Other Capacity.
(1a) Subroutine: CARM Load is first assigned to CARM Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G and Supplemental Transfer Other Schedule or Post S&G And Supplemental Transfer Load.
(3) Subroutine: CARM Excess S&G And Supplemental Capacity is allocated as CARM S&G And Supplemental Transfers proportionately based on need to Member* Other Schedule and Member* CA Post Base Load, until such CARM Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule and Member* CA Post Base Load are satisfied.
(4) Subroutine: Member*, Member* CA Excess Base Capacity is allocated proportionately based on need to CARM and Member* CA Post-S&G And Supplemental TransferLoad and Member* Post-S&G And Supplmental Transfer Other Schedule until such Member*, Member* CA Excess Base Capacity is consumed, or until such CARM and Member* CA Post S&G and Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule are satisfied.
(5) Subroutine: CARM Excess Base Capacity is allocated proportionately based on need to Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post S&G And Supplemental Transfer Load until such *CARM Excess Base Capacity is consumed, or until Member* Post S&G And Supplemental Transfer Other Schedule and Member* CA Post* S&G And Supplemental TransferLoad are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

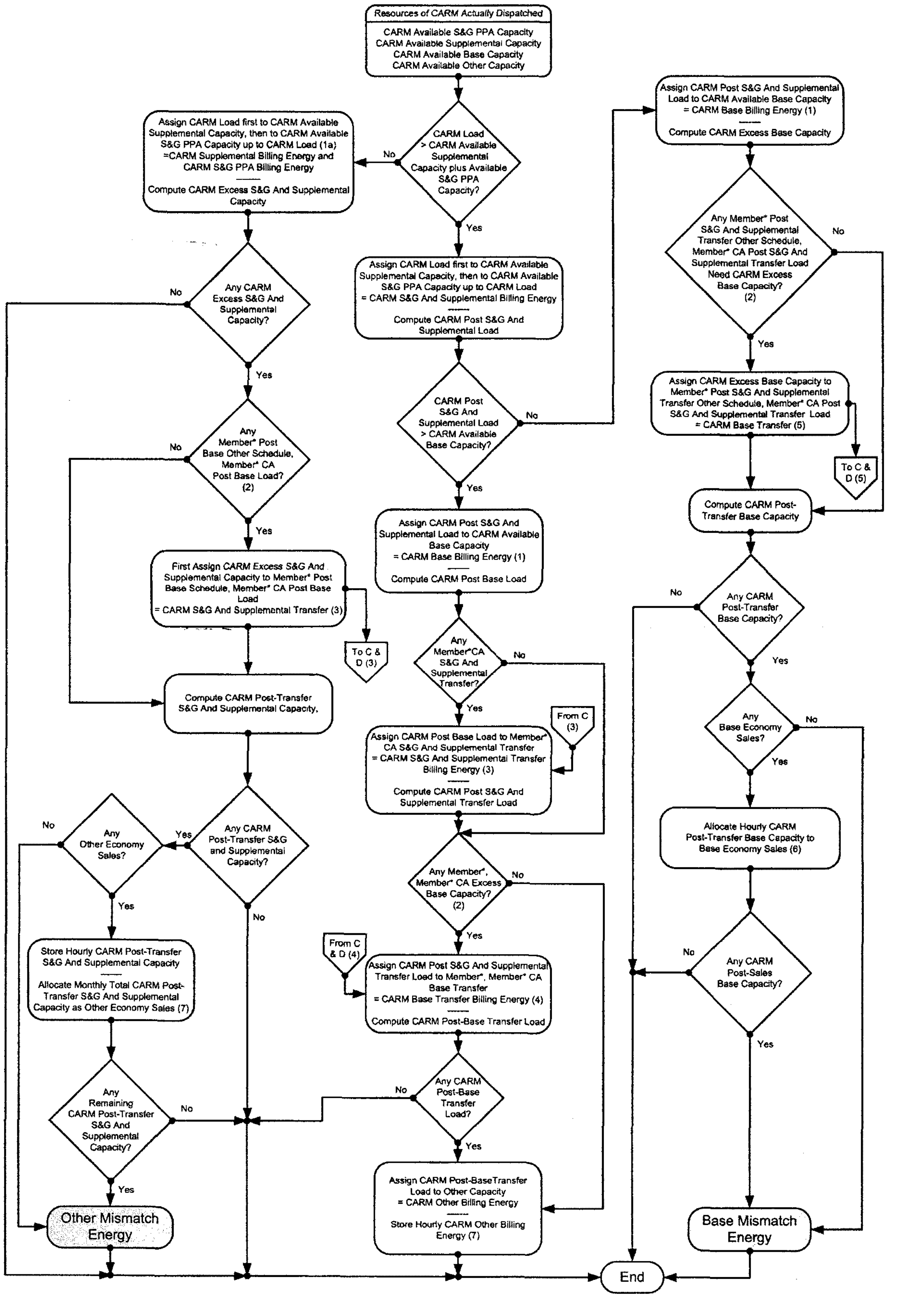
Appendix C Footnotes:

(1) Subroutine: Member* CA Post S&G And Supplemental Load is first assigned to Member* CA Minimum Other Capacity.
(1a) Subroutine: Member* CA Directed Sales and Load is first assigned to Member* CA Minimum Other Capacity.
(2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA Excess S&G And Supplemental Capacity is allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and *Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member** CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* CA Excess Base Capacity is allocated proportionately based on need to Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.

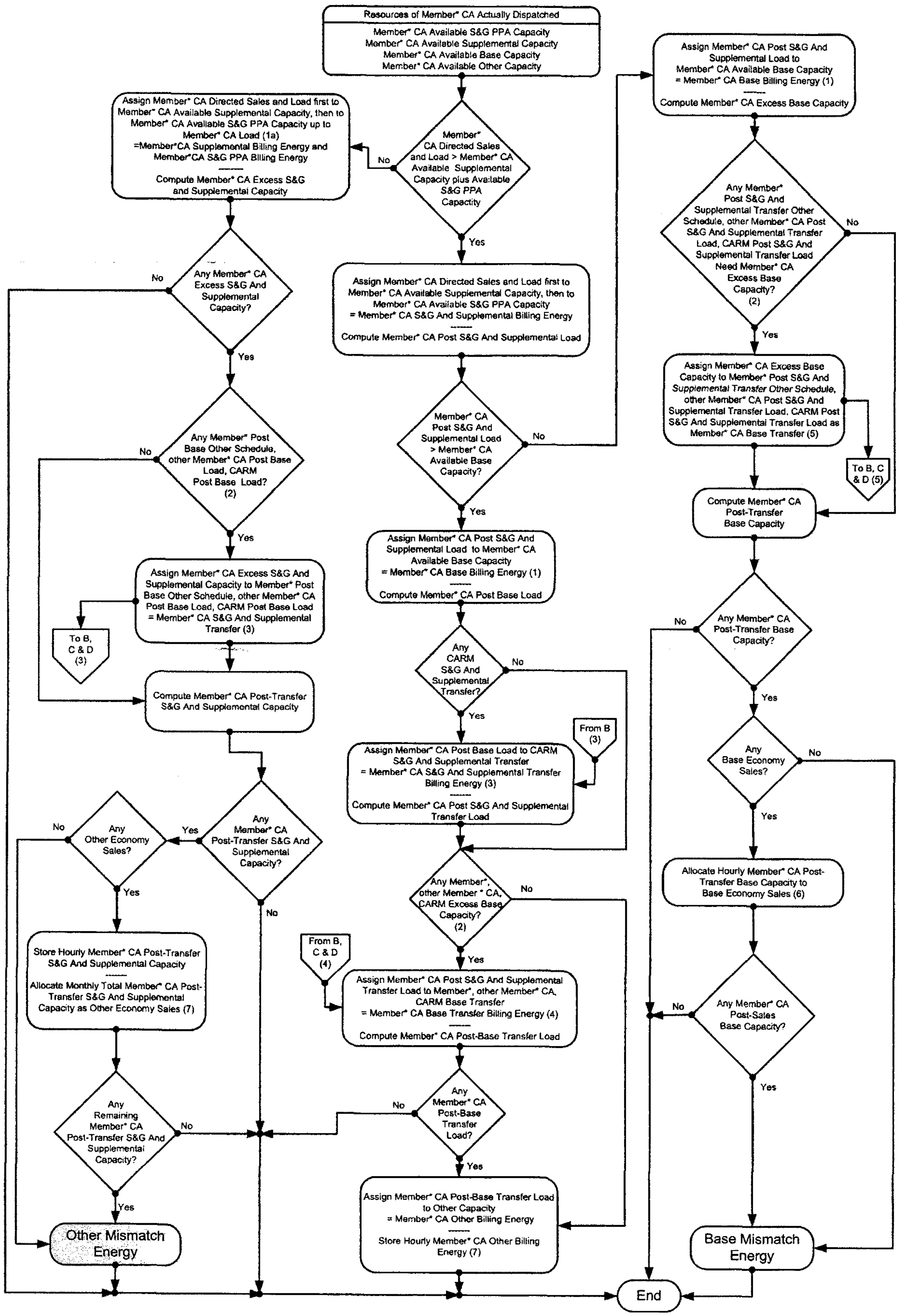
Appendix D Footnotes:

(1) Subroutine: Member* Base Schedule is first assigned to Member* Minimum Other Capacity.
(2) Subroutine: (2) Subroutine: Determines the extent to which other Billing Unit Entities need Excess Base Capacity of other Billing Unit Entities for their Post S&G And Supplemental Transfers Other Schedule or Post S&G And Supplemental TransferLoad which can be assigned to this Billing Unit Entity's Excess Base Capacity.
(3) Subroutine: Member* CA and CARM Excess S&G And Supplemental Capacity are allocated as Member* CA S&G And Supplemental Transfers proportionately based on need to Member* Post Base Other Schedule, CARM Post Base Load, and other Member* CA Post Base Load, until such Member* CA Excess S&G And Supplemental Capacity is consumed, or until Member* Post Base Other Schedule, other Member* CA Post Base Load and CARM Post Base Load are satisfied.
(4) Subroutine: Member*, CARM, and other Member* CA Excess Base Capacity are allocated proportionately based on need to CARM and other Member* CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Transfer Other Schedule until such Member*, CARM and other Member* CA Excess Base Capacity are consumed, or until such CARM and other Member*CA Post-S&G And Supplemental Transfer Load and Member* Post-S&G And Supplemental Other Schedule are satisfied.
(5) Subroutine: Member* Excess Base Capacity is allocated proportionately based on need to each Member* Post-S&G And Supplemental Transfer Other Schedule, other Member * CA Post-S&G And Supplemental TransferLoad, and CARM Post-S&G And Supplemental Transfer Load until such Member* CA Excess Base Capacity is consumed, or until Member* Post-S&G And Supplemental Transfer Other Schedule, other Member* CA Post-S&G And Supplemental Transfer Load and CARM Post-S&G And Supplemental Transfer Load are satisfied.
(6) Subroutine: CARM Post Transfer Base Capacity, Member* CA Post Transfer Base Capacity, and Member* Post Transfer Base Capacity are assigned hourly to Base Economy Sales.
(7) Subroutine: CARM Post Transfer S&G And Supplemental Capacity, Member* CA Post Transfer S&G And Supplemental Capacity, CARM Other Billing Energy, Member* CA Other Billing Energy, and Member* Other Billing Energy are used to apportion and allocate monthly Other Economy Sales.
(8) No Partial Requirements Member with an interest in S&G PPA currently plans to operate outside the AEPCO pseudo-control area. In the event that a Partial Requirements Member with such an interest chooses to operate outside the AEPCO pseudo-control area in the future, the Appendix D flow chart for such a Member* will need to be modified.

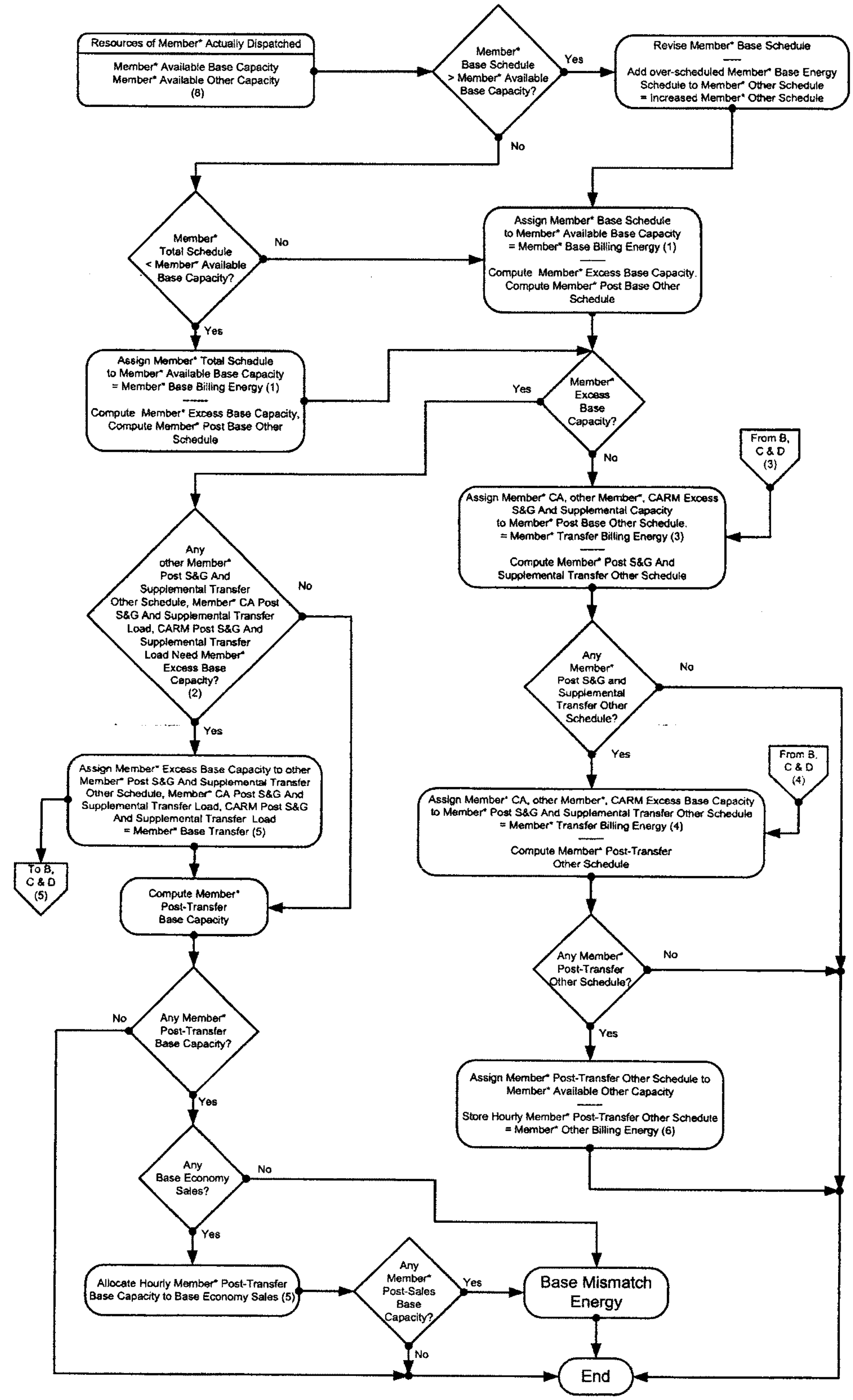
Appendix B to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
CARM Load Use of AEPCO Resources and Assignments as Additional and Base Transfers and AEPCO Third Party Sales



Appendix C to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* CA Load use of AEPCO Resources and Assignments as S&G PPA and Base Transfers and AEPCO Third Party Sales

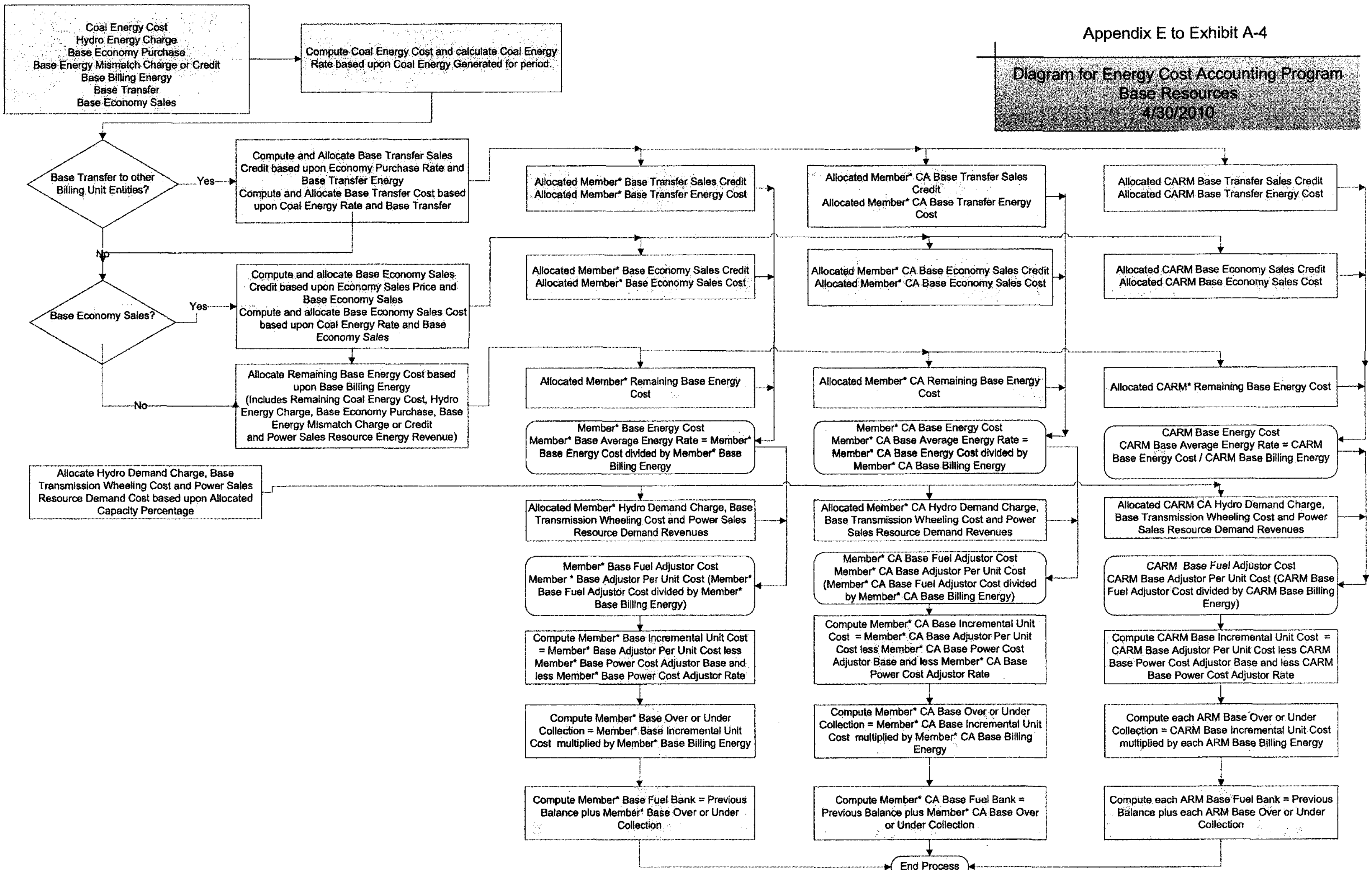


Appendix D to Exhibit A-4 to Rate Schedule A: Billing Unit Program Flow Diagram
Member* Use of AEPCO Resources and Assignments as Base Transfers and AEPCO Third Party Sales



Appendix E to Exhibit A-4

Diagram for Energy Cost Accounting Program
Base Resources
4/30/2010



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Appendix F to Exhibit A-4

Diagram for Energy Cost Accounting Program
Other Resources
4/30/2010

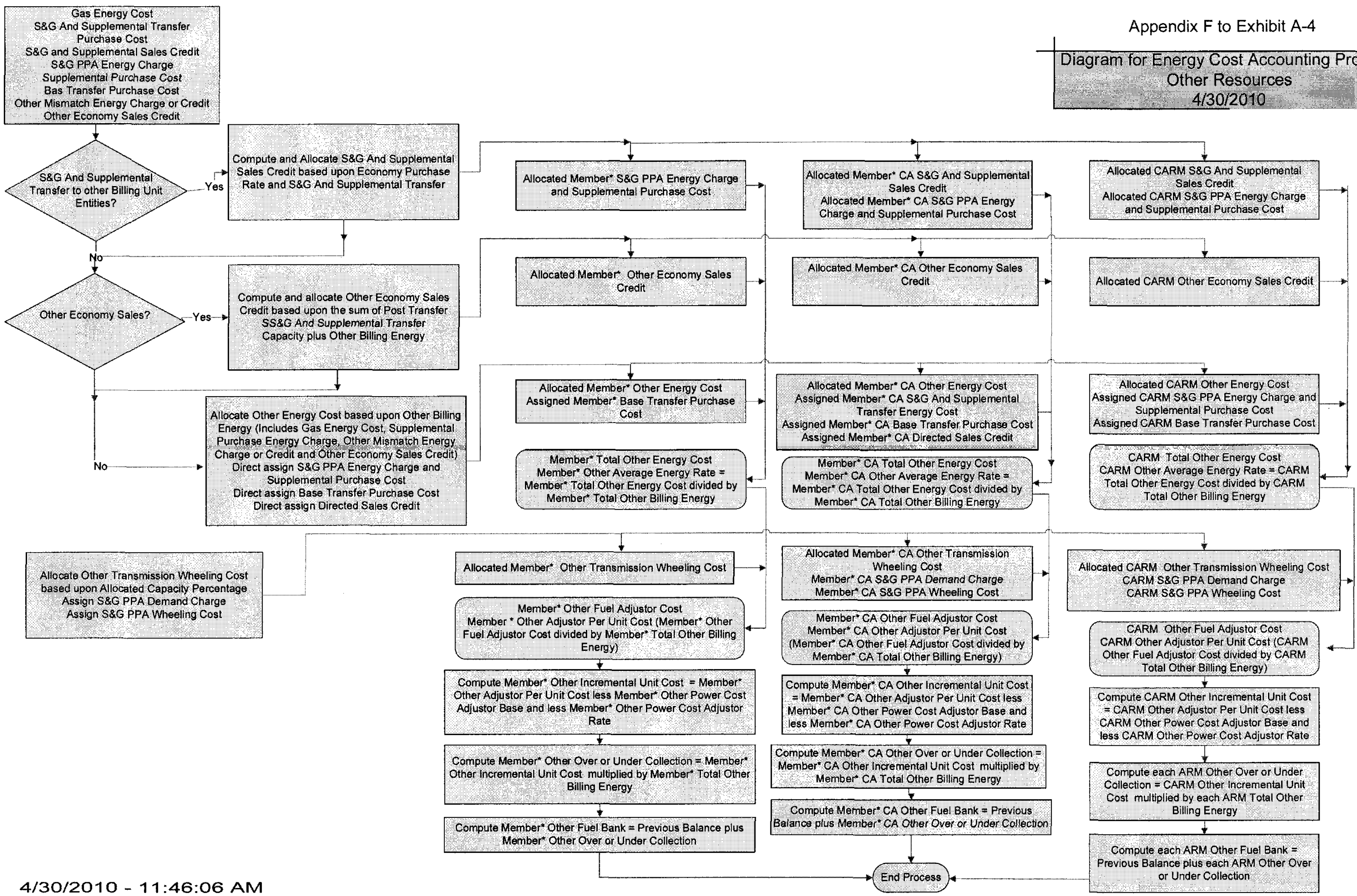

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Exhibit A-5 to Rate Schedule A
Allocated Capacity Percentages (ACP),
Allocated Capacity (AC)
and Reserves

ACP and AC DETERMINATION

An Allocated Capacity Percentage (ACP) was developed for Existing Resources as of the Effective Date for each Class A Member based on load forecasts from the 1996 Power Requirements Study (1996 PRS). The ACP in Existing Resources is used to calculate the Allocated Capacity (AC) for each Partial Requirements Member (PRM), and each All Requirements Member (ARM) in Existing Resources.

At the outset of AEPCO's restructuring, AEPCO, all AEPCO Class A Members, and RUS had approved the use of the 1996 PRS for planning purposes. AEPCO and its Class A Members agreed to the specific use of the 1996 PRS and forecast year 2000 as the basis for calculating the ACP in Existing Resources 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 in Existing Resources is summarized in Part A of Appendix A to this Exhibit A-5. The ACP calculation for Existing Resources utilized the forecasted year 2000 monthly coincident peaks of the Class A Members, which were obtained by multiplying: (a) each Member's forecasted monthly non-coincident peak as identified in the 1996 PRS, by (b) a historical three-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 an ARM in Existing Resources shall be used to determine its AC in Existing Resources in the event such ARM elects to become a Partial Requirements Member pursuant to the Conversion Agreement between the Class A Members and AEPCO dated August 1, 2001 (Conversion Agreement). The sum of the ACP's of the ARMs shall be the ACP of the Collective ARM (CARM) for purposes of Rate Schedule A to Existing Wholesale Power Contracts.

The monthly AC assigned to each PRM and the CARM from Existing Resources has been calculated by: (1) determining the capacity (in MW) of the generating units that comprise Existing Resources; (2) determining the Reserve percentage (described hereinafter) to be set aside from the generating units that comprise Existing Resources; (3) subtracting the Power Sales Resources as of the Closing Date of AEPCO's restructuring, including associated reserves and delivery losses attributable to such Power Sales: (4) further reducing the Existing Resource generating unit capacity for AEPCO generating unit reserves and delivery losses; (5) adding the monthly capacity from the Federal Hydro Power Agreements; and (6) multiplying such net capacity of Existing Resources by the ACP of each PRM and the CARM.

The AC in Existing Resources of each PRM and the CARM is further subdivided into Available Base Capacity and Available Other Capacity and shall be as shown on Appendix B to this Exhibit A-5. The Available Base Capacity of each PRM and the CARM shall be the respective

ACP shares of Base Resources after reduction for delivery losses. The Available Other Capacity shall be the respective ACP share of Other Resources after reduction for reserves and delivery losses.

For AEPCO Resources added and not included as Existing Resources (currently the S&G PPA Resource), each Class A Member participating in the added Resource accepts an ACP in that Resource pursuant to its agreement with AEPCO. That ACP shall be derived by a method determined by AEPCO based on adequacy of Resources to meet the forecasted loads of participating Class A Members under a method adopted by the AEPCO Board of Directors prior to AEPCO's commitment to the added Resource. Each participating Class A Member's AC in the Resource shall be the product of its ACP in the added Resource multiplied by the capacity of the Resource after reduction for delivery losses, and if required, reserves.

The ACP of the participating Class A Members as a PRM or as a part of CARM in an added Resource shall be set forth in a revision to Appendix A to this Exhibit A-5. The AC of such participating Class A Members as a PRM and as the CARM in an added Resource shall be set forth in a revision to Appendix B to this Exhibit A-5. Both the Appendices A and B as so revised shall be provided by AEPCO to all Class A Members at the time of the commitment by AEPCO to the added Resource. No such revision of Appendices A and B shall affect the ACP and AC of the non-participating Class A Members.

The ACP for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix A to this Exhibit A-5, and the AC for the S&G PPA Resource for TRICO and the CARM shall be as set forth in the attached Appendix B to this Exhibit A-5. Neither the ACP nor the AC of the S&G PPA Resource shall be changed absent the agreement of TRICO and the participating ARMs that comprise the CARM.

RESERVE PERCENTAGE DETERMINATION:

In accordance with WECC reliability criteria, AEPCO is required to have in reserve access to generation sufficient to cover AEPCO's largest single generating unit hazard. AEPCO's largest single generating hazard consists of an outage of 188 MW of coal-fired steam generating unit capacity (which includes 13 MW of spinning reserve capacity), and after the first hour of such an outage includes an additional 29 MW, which 29 MW is subject to call from AEPCO by other members of the Southwest Reserve Sharing Group pursuant to the Southwest Reserve Sharing Group agreement, to which AEPCO is party. For the first hour of the outage, AEPCO currently relies on the generating support of other members of the Southwest Reserve Sharing Group to cover AEPCO's largest single generating unit outage.

Based on the above, AEPCO shall seek to reduce the MW of generation that would be required to be set aside for coverage of AEPCO's largest single generating unit by purchasing reserved transmission capacity from Southwest Transmission Cooperative, Inc., Mohave Electric Cooperative, Inc. and others as available, in that order of priority. AEPCO shall seek such transmission capacity in amounts necessary to realize AEPCO's reserve generating unit capacity percentage as 6.7% from 2011 through 2020, and 7.0% for the period from 2021 through 2035, which are the reserve capacity percentages as set forth in Appendix B to this Exhibit A-5. AEPCO and SWTC shall annually agree to a plan for AEPCO to follow to seek to obtain such transmission capacity, which shall be provided to the Class A Members for review. To the

extent AEPCO obtains transmission capacity in accordance with the established plan, the Class A Members agree that AEPCO shall include the costs of such transmission capacity in AEPCO's rates to such Class A Members.

In the event AEPCO is unsuccessful or less than fully successful in its attempts to timely purchase such reserved transmission capacity in advance of the start of any calendar year, AEPCO shall have the unilateral right to increase the reserve capacity percentage of Appendix B to this Exhibit A-5 for such calendar year. In such event, AEPCO shall provide, timely in advance of the start of such calendar year, a revised Appendix B to this Exhibit A for such calendar year that shows the effect of such increased reserve capacity percentage on the Available Base Capacity and Available Other Capacity of each PRM and the CARM. AEPCO and the Class A Members shall use such revised Available Base Capacity and Available Other Capacity for the purposes of Exhibit A-4 in the affected calendar year.

Appendix A to Exhibit A-5

Schedule of Allocated Capacity Percentages

A. The schedule and calculation of the Allocated Capacity Percentages (ACP) for AEPCO Existing Resources existing as of August 1, 2001 (consisting of Existing Resources as set forth in Appendix B to Exhibit A-5) is shown below:

		Allocated Capacity Percentage						
		1996 PRS Coincident Peak Demand Forecast – MW						
Col.		1	2	3	4	5	6	7
Ln.	Year 2000	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
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	ACP	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

B. The Allocated Capacity Percentages (ACP's) for the S&G PPA 1 Resource consisting of the South Point and Griffth PPAs is 0% for both MEC and SSVEC. For the remaining Class A Members and the CARM, the resulting ACP's for the S&G PPA Resource are as follows:

	Anza	DVEC	GCEC	CARM	TRICO	Total
Allocated Capacity %	0.1%	0.1%	3.0%	3.2%	96.8%	100%

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2011

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	15.0	15.0	15.0	15.0	15.0	15.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources			8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves	(4)	2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity			534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP		21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP		35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP		31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves	(5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves			11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members			36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	48.8	48.8	48.8	48.8	48.8	48.8	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	1.6	1.6	1.6	1.6	1.6	1.6	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	47.2	47.2	47.2	47.2	47.2	47.2	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total AC			109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total AC			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity	(8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity	(8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity	(8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base		100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			58.9	58.9	59.5	60.1	61.7	61.7	61.8	61.8	61.7	60.5	58.9	58.9
TRICO Total Available Capacity			109.1	109.1	110.1	111.3	158.5	158.6	158.7	158.7	158.4	156.2	109.0	109.1
MEC Total Available Capacity			185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity			167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total			520.9	520.9	525.9	531.3	580.3	580.6	581.3	581.0	580.0	569.5	520.7	520.9

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2012

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources													
Apache ST-2 Coal-fired		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 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA (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
Fed Hydro - Parker-Davis PPA (1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources		368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources		205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA (1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources		573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation													
2nd Hr Reserves Reqd for LSH Plus 29 MW (2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available		40.0	40.0	40.0	40.0	5.0	5.0	5.0	5.0	5.0	5.0	40.0	40.0
Less: SWTC Transmission Reserved		90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved		0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Less: Transmission Import Capacity (3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap) (3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW													
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
Power Sales Resources		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less Power Sales Losses (4)	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
Less Power Sales Reserves - MW		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
SubTotal for Power Sales Resources		8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Net Existing Resource Capacity													
Existing Resoucre Units after Pwr Sales		546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3	546.3
Less Member Losses after Reserves (4)	2.31%	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Net Existing Resource Unit Capacity		534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5	534.5
Existing Fed Hydro Capacity		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity		553.4	553.4	558.3	563.8	563.9	564.2	565.1	564.7	563.7	553.2	553.2	553.4
Portion of Member Capacity Net of Losses													
CARM Existing Resource @ ACP	11.4%	63.1	63.1	63.7	64.3	64.3	64.3	64.4	64.4	64.3	63.1	63.1	63.1
TRICO Existing Resource @ ACP	21.1%	116.8	116.8	117.8	119.0	119.0	119.1	119.2	119.2	118.9	116.7	116.7	116.8
MEC Existing Resource @ ACP	35.8%	198.1	198.1	199.9	201.9	201.9	202.0	202.3	202.2	201.8	198.1	198.1	198.1
SSVEC Existing Resource @ ACP	31.7%	175.4	175.4	177.0	178.7	178.8	178.9	179.1	179.0	178.7	175.4	175.4	175.4
Member Reserve Shares (MW)													
CARM Reserves		4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves		7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
MEC Reserves (5)		13.0	13.0	13.0	13.1	13.0	13.0	13.0	13.1	13.0	13.1	13.1	13.0
SSVEC Reserves		11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Less: EuroFresh Reserve Credit (6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources		7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Total Reserves Req'd of Class A Members		36.5	36.5	36.5	36.6	36.5	36.5	36.5	36.6	36.5	36.6	36.6	36.5
S&G PPA Resources													
Griffith Purchased Power		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power		0.0	0.0	0.0	0.0	35.0	35.0	35.0	35.0	35.0	35.0	0.0	0.0
Total S&G PPA Resources		0.0	0.0	0.0	0.0	60.0	60.0	60.0	60.0	60.0	60.0	0.0	0.0
Total After Network Losses		0.0	0.0	0.0	0.0	58.6	58.6	58.6	58.6	58.6	58.6	0.0	0.0
CARM Available S&G Capacity	3.2%	0.0	0.0	0.0	0.0	1.9	1.9	1.9	1.9	1.9	1.9	0.0	0.0
TRICO Available S&G Capcity	96.8%	0.0	0.0	0.0	0.0	56.7	56.7	56.7	56.7	56.7	56.7	0.0	0.0
Member Total Allocated Capacity (MW)													
CARM Total AC		58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total AC		109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total AC		185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total AC		167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total		520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9
Member Available Base Capacity After Power Sales, Losses (MW)													
CARM Available Base Capacity (8)	11.4%	40.2	40.2	40.8	41.4	41.4	41.4	41.5	41.5	41.4	40.2	40.2	40.2
TRICO Available Base Capacity (8)	21.1%	74.5	74.5	75.5	76.7	76.7	76.8	76.9	76.9	76.6	74.4	74.4	74.5
MEC Available Base Capacity (8)	35.8%	126.3	126.3	128.1	130.0	130.1	130.2	130.5	130.3	130.0	126.2	126.2	126.3
SSVEC Available Base Capacity (8)	31.7%	111.8	111.8	113.4	115.1	115.2	115.3	115.5	115.4	115.1	111.8	111.8	111.8
Subtotal Base	100.0%	352.8	352.8	357.8	363.2	363.4	363.7	364.4	364.1	363.1	352.6	352.6	352.8
Member Available Other Capacity After Losses, Reserves (MW)													
CARM Available Other Capacity (8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity (8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity (8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity (8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap		168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)													
CARM Total Available Capacity		58.9	58.9	59.5	60.1	62.0	62.0	62.1	62.1	62.0	60.8	58.9	58.9
TRICO Total Available Capacity		109.1	109.1	110.1	111.3	168.0	168.1	168.2	168.2	167.9	165.7	109.0	109.1
MEC Total Available Capacity		185.1	185.1	186.9	188.8	188.9	189.0	189.3	189.1	188.8	185.0	185.0	185.1
SSVEC Total Available Capacity		167.8	167.8	169.4	171.1	171.2	171.3	171.5	171.4	171.1	167.8	167.8	167.8
Total		520.9	520.9	525.9	531.3	590.1	590.4	591.1	590.8	589.8	579.3	520.7	520.9
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Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.

(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.

(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.

(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.

(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.

(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.

(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..

(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2013

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power			0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	0.0	0.0
Total S&G PPA Resources			0.0	0.0	0.0	0.0	70.0	70.0	70.0	70.0	70.0	70.0	0.0	0.0
Total After Network Losses			0.0	0.0	0.0	0.0	68.4	68.4	68.4	68.4	68.4	68.4	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	66.2	66.2	66.2	66.2	66.2	66.2	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	607.9	608.1	609.0	608.6	607.6	597.1	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(8)	35.8%	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8	58.8
SSVEC Available Other Capacity	(8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	63.3	63.3	63.4	63.3	63.2	62.0	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	179.2	179.2	179.4	179.4	179.1	176.9	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.7	191.6	191.7	191.8	192.1	192.0	191.6	187.9	187.9	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.9	539.3	608.0	608.2	609.0	608.7	607.6	597.2	528.8	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2014

All Values in MW Unless Indicated		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources													
Apache ST-2 Coal-fired		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 Coal-fired		175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units		350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA (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
Fed Hydro - Parker-Davis PPA (1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources		368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1		82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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		65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4		38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources		205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA (1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources		573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation													
2nd Hr Reserves Reqd for LSH Plus 29 MW (2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement		50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available		40.0	40.0	40.0	40.0	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	40.0	40.0
Less: SWTC Transmission Reserved		90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved		0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Less: Transmission Import Capacity (3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requirement (MW)		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap) (3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW													
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
Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses (4)	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
Less Power Sales Reserves - MW		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity													
Existing Resoucre Units after Pwr Sales		555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves (4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity		543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity		561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses													
CARM Existing Resource @ ACP	11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP	21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP	35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP	31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)													
CARM Reserves		4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves		7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves (5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves		11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit (6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources		7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members		37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources													
Griffith Purchased Power (7)		0.0	0.0	0.0	0.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
South Point Purchased Power (7)		0.0	0.0	0.0	0.0	55.0	55.0	55.0	55.0	55.0	55.0	0.0	0.0
Total S&G PPA Resources		0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0
Total After Network Losses		0.0	0.0	0.0	0.0	78.2	78.2	78.2	78.2	78.2	78.2	0.0	0.0
CARM Available S&G Capacity	3.2%	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	0.0	0.0
TRICO Available S&G Capcity	96.8%	0.0	0.0	0.0	0.0	75.7	75.7	75.7	75.7	75.7	75.7	0.0	0.0
Member Total Allocated Capacity (MW)													
CARM Total AC		59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total AC		110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total AC		187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC		170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total		529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)													
CARM Available Base Capacity (8)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity (8)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity (8)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity (8)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base	100.0%	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)													
CARM Available Other Capacity (8)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity (8)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity (8)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity (8)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap		168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)													
CARM Total Available Capacity		59.9	59.9	60.4	61.0	63.6	63.6	63.7	63.6	63.5	62.3	59.8	59.9
TRICO Total Available Capacity		110.8	110.8	111.8	113.0	188.7	188.7	188.9	188.9	188.6	186.4	110.7	110.8
MEC Total Available Capacity		187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity		170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total		529.0	529.0	533.8	539.3	617.7	617.9	618.8	618.4	617.4	606.9	528.7	529.0

Notes: (1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Griffith PPA is available only in WECC Peak Hours; SouthPoint PPA is available only in Daytime Hours..
(8) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A
PRM and CARM Monthly Allocated Capacity for 2015 thru 2020

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
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			65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Subtotal Existing Resource Units			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			573.9	573.9	578.8	584.3	584.4	584.7	585.6	585.2	584.2	573.7	573.7	573.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0
Remaining Reserve Requrement (MW)			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
Reserve Requrement (% of Unit Cap)	(3)		6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%
Power Sales Resources MW														
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
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0	555.0
Less Member Losses after Reserves	(4)	2.31%	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Net Existing Resource Unit Capacity			543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0	543.0
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			561.9	561.9	566.8	572.3	572.4	572.7	573.6	573.2	572.2	561.7	561.7	561.9
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	64.100	64.1	64.6	65.2	65.3	65.3	65.4	65.3	65.2	64.0	64.0	64.1
TRICO Existing Resource @ ACP		21.1%	118.600	118.6	119.6	120.8	120.8	120.8	121.0	121.0	120.7	118.5	118.5	118.6
MEC Existing Resource @ ACP		35.8%	201.200	201.2	202.9	204.9	204.9	205.0	205.4	205.2	204.9	201.1	201.1	201.2
SSVEC Existing Resource @ ACP		31.7%	178.100	178.1	179.7	181.4	181.5	181.6	181.8	181.7	181.4	178.1	178.1	178.1
Member Reserve Shares (MW)														
CARM Reserves			4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
TRICO Reserves			7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
MEC Reserves	(5)		13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
SSVEC Reserves			11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Total Reserves Req'd of Class A Members			37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			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 S&G PPA Resources			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 After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total AC			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total AC			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total AC			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.2	41.2	41.7	42.3	42.4	42.4	42.5	42.4	42.3	41.1	41.1	41.2
TRICO Available Base Capacity	(7)	21.1%	76.2	76.2	77.2	78.4	78.4	78.4	78.6	78.6	78.3	76.1	76.1	76.2
MEC Available Base Capacity	(7)	35.8%	129.1	129.1	130.9	132.8	132.9	133.0	133.3	133.2	132.8	129.1	129.1	129.1
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.4	116.0	117.7	117.8	117.9	118.1	118.0	117.7	114.4	114.4	114.4
Subtotal Base		**100.0%**	360.9	360.9	365.8	371.2	371.5	371.7	372.5	372.2	371.1	360.7	360.7	360.9
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
TRICO Available Other Capacity	(7)	21.1%	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6	34.6
MEC Available Other Capacity	(7)	35.8%	58.8	58.8	58.7	58.8	58.7	58.7	58.8	58.7	58.8	58.7	58.7	58.8
SSVEC Available Other Capacity	(7)	31.7%	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0
Subtotal Available Other Cap			168.1	168.1	168.0	168.1	168.0	168.0	168.1	168.0	168.1	168.0	168.0	168.1
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			59.9	59.9	60.4	61.0	61.1	61.1	61.2	61.1	61.0	59.8	59.8	59.9
TRICO Total Available Capacity			110.8	110.8	111.8	113.0	113.0	113.0	113.2	113.2	112.9	110.7	110.7	110.8
MEC Total Available Capacity			187.9	187.9	189.6	191.6	191.6	191.7	192.1	191.9	191.6	187.8	187.8	187.9
SSVEC Total Available Capacity			170.4	170.4	172.0	173.7	173.8	173.9	174.1	174.0	173.7	170.4	170.4	170.4
Total			529.0	529.0	533.8	539.3	539.5	539.7	540.6	540.2	539.2	528.7	528.7	529.0

Notes:
(1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) *MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.*
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

APPENDIX B to Exhibit A-5 to Rate Schedules A

PRM and CARM Monthly Allocated Capacity for 2021 thru 2035

All Values in MW Unless Indicated			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Resources														
Apache ST-2 Coal-fired			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 Coal-fired			175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0
Subtotal Base Units			350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Fed Hydro - SLCA IP PPA	(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
Fed Hydro - Parker-Davis PPA	(1)		17.3	17.3	22.4	22.4	22.4	22.4	22.4	22.4	22.4	17.3	17.3	17.3
Sub Total Base Resources			368.9	368.9	373.8	379.3	379.4	379.7	380.6	380.2	379.2	368.7	368.7	368.9
Apache CC-1			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-2			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-3			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apache GT-4			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Other Resources			38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Subtotal Existing Resource Units			388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Subtotal Fed Hydro PPA	(1)		18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resources			406.9	406.9	411.8	417.3	417.4	417.7	418.6	418.2	417.2	406.7	406.7	406.9
Reserve Caculation														
2nd Hr Reserves Reqd for LSH Plus 29 MW	(2)		217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0	217.0
Less: WW-Mead-Davis Displacement			50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Less: AEPCO Wheeling Available			40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Less: SWTC Transmission Reserved			100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Less: Western/MEC Transmission Reserved			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: Transmission Import Capacity	(3)		190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0
Remaining Reserve Requrement (MW)			27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Reserve Requrement (% of Unit Cap)	(3)		7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Power Sales Resources MW														
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
Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Power Sales Losses	(4)	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
Less Power Sales Reserves - MW			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SubTotal for Power Sales Resources			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Existing Resource Capacity														
Existing Resoucre Units after Pwr Sales			388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0	388.0
Less Member Losses after Reserves	(4)	2.31%	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Net Existing Resource Unit Capacity			379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7	379.7
Existing Fed Hydro Capacity			18.9	18.9	23.8	29.3	29.4	29.7	30.6	30.2	29.2	18.7	18.7	18.9
Total Existing Resource Capacity			398.6	398.6	403.5	409.0	409.1	409.4	410.3	409.9	408.9	398.4	398.4	398.6
Portion of Member Capacity Net of Losses														
CARM Existing Resource @ ACP		11.4%	45.4	45.4	46.0	46.6	46.6	46.7	46.8	46.7	46.6	45.4	45.4	45.4
TRICO Existing Resource @ ACP		21.1%	84.1	84.1	85.1	86.3	86.3	86.4	86.6	86.5	86.3	84.1	84.1	84.1
MEC Existing Resource @ ACP		35.8%	142.7	142.7	144.4	146.4	146.4	146.6	146.9	146.7	146.4	142.6	142.6	142.7
SSVEC Existing Resource @ ACP		31.7%	126.4	126.3	127.9	129.6	129.7	129.8	130.1	129.9	129.6	126.3	126.3	126.3
Member Reserve Shares (MW)														
CARM Reserves			3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
TRICO Reserves			5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
MEC Reserves	(5)		9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
SSVEC Reserves			8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Less: EuroFresh Reserve Credit	(6)		(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)
Net SSVEC from Existing Resources			4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Total Reserves Req'd of Class A Members			27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
S&G PPA Resources														
Griffith Purchased Power			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Point Purchased Power			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 S&G PPA Resources			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 After Network Losses			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARM Available S&G Capacity		3.2%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRICO Available S&G Capcity		96.8%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Member Total Allocated Capacity (MW)														
CARM Total AC			42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total AC			78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total AC			133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total AC			121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total			375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5
Member Available Base Capacity After Power Sales, Losses (MW)														
CARM Available Base Capacity	(7)	11.4%	41.1	41.1	41.7	42.3	42.3	42.4	42.5	42.4	42.3	41.1	41.1	41.1
TRICO Available Base Capacity	(7)	21.1%	76.1	76.1	77.1	78.3	78.3	78.4	78.6	78.5	78.3	76.1	76.1	76.1
MEC Available Base Capacity	(7)	35.8%	129.2	129.2	130.9	132.9	132.9	133.1	133.4	133.2	132.9	129.1	129.1	129.2
SSVEC Available Base Capacity	(7)	31.7%	114.4	114.3	115.9	117.6	117.7	117.8	118.1	117.9	117.6	114.3	114.3	114.3
Subtotal Base		100.0%	360.8	360.7	365.6	371.1	371.2	371.7	372.6	372.0	371.1	360.6	360.6	360.7
Member Available Other Capacity After Losses, Reserves (MW)														
CARM Available Other Capacity	(7)	11.4%	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
TRICO Available Other Capacity	(7)	21.1%	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
MEC Available Other Capacity	(7)	35.8%	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
SSVEC Available Other Capacity	(7)	31.7%	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Subtotal Available Other Cap			14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Member Total Available Capacity with Available S&G Capacity (MW)														
CARM Total Available Capacity			42.3	42.3	42.9	43.5	43.5	43.6	43.7	43.6	43.5	42.3	42.3	42.3
TRICO Total Available Capacity			78.4	78.4	79.4	80.6	80.6	80.7	80.9	80.8	80.6	78.4	78.4	78.4
MEC Total Available Capacity			133.1	133.1	134.8	136.8	136.8	137.0	137.3	137.1	136.8	133.0	133.0	133.1
SSVEC Total Available Capacity			121.8	121.7	123.3	125.0	125.1	125.2	125.5	125.3	125.0	121.7	121.7	121.7
Total			375.6	375.5	380.4	385.9	386.0	386.5	387.4	386.8	385.9	375.4	375.4	375.5

Notes:
(1) Federal Hydro Estimated - AEPCO will establish Fed Hydro portion of Available Base Capacity monthly pursuant to the Federal Hydro Power Agreements.
(2) The 29 MW value added to LSH Reserves of 188 MW of Coal Unit capacity (includes spinning reserve capability) is required to restore SRSG Operating Reserves.
(3) The Class A Members have agreed that AEPCO will purchase transmission import capacity from SWTC or others as needed to hold generating reserves to 6.7%.
(4) The SWTC loss factors are subject to change from time to time as changes are implemented to such loss factors pursuant to SWTC's OATT Tariff.
(5) MEC Reserve fraction is rounded to ensure total reserves match totall reserves required of Class A members.
(6) Credit for Operating Reserve contribution from EuroFresh generation controlled by SSVEC pursuant to AEPCO-SSVEC agreement.
(7) Class A Member Available Base and Other Capacity fractions are rounded up and down as needed to match total AC.

Exhibit A-6: Sample Bill

INVOICE

To: Member *
Address
City, AZ

'ATTN:

Member * | ACP %

DATE: February 10, 2011

January, 2011				
				Total $
Fixed Charge				
O&M Charge				
		kwh	$/kwh	Total $
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
Minimum Other Capacity Charge				
	DOAF			
Demand Overrun Adjustment	%			
Overrun Energy Charge				
	mkW	12MORA		
Power Factor Adjustor				
ACC Gross Operating Revenue Assessment				

Exhibit A-6: Sample Data for Bill Member * 1	Monthly MWH
Base Billing Energy	
Base Economy Purchases	
Off-peak	
On-Peak	
Base Transfer delivered	
Off-peak	
On-Peak	
Base Economy Sales credits	
Off-peak	
On-Peak	
Base Mismatch Energy	
Other Billing Energy	
Off-peak	
On-Peak	
Supplemental Transfer Billing Energy received	
Off-peak	
On-Peak	
S&G PPA Transfer Billing Energy received	
Off-peak	
On-Peak	
Base Transfer Billing Energy received	
Off-peak	
On-Peak	
Total Other Energy	
Off-peak	
On-Peak	
Other Mismatch Energy	
Other Ecomony Sales credits	

Exhibit A-6: Sample Bill

INVOICE

To: Member * CA
Address
City, AZ

'ATTN:

Member * CA		ACP %		
DATE:				February 10, 2011
January, 2011				
				Total $
Fixed Charge				
O&M Charge				
		kwh	$/kwh	Total $
Base Billing Energy				
Base Energy Fuel Adjustor				
Other Billing Energy				
Supplemental Billing Energy				
Supplemental Billing Energy Fuel Adjustor				
S&G PPA Billing Energy				
S&G PPA Energy Fuel Adjustor				
Other Billing Energy				
Other Energy Fuel Adjustor				
Minimum Base Capacity Charge				
Minimum Other Capacity Charge				
	DOAF			
Demand Overrun Adjustment	%			
Overrun Energy Charge				
	mkW	12MORA		
Power Factor Adjustor				

ATTACHMENT 3 to First Amendment to Partial Agreement

Schedule B

SCHEDULE B
TO PARTIAL REQUIREMENTS AGREEMENTS
Dated May 11, 2010
PRM RIGHTS, ABILITIES, AND CONSTRAINTS ASSOCIATED WITH ENERGY FROM AEPCO RESOURCES

1. INTRODUCTION

The primary purpose of this Schedule B is to define how a Partial Requirements Member (PRM) will access its entitlement to energy available from its AC in AEPCO Resources, such energy purchased pursuant to the Partial Requirements Capacity and Energy Agreement between Arizona Electric Power Cooperative, Inc. (AEPCO) and Member (Agreement) at the energy rates set forth in Exhibit A-1 to Rate Schedule A. This Schedule B defines available AEPCO Resources and the minimum capacity requirements for such resources, and how a PRM will schedule energy from AEPCO Resources in a manner consistent with such minimums and the Cost Causation principles upon which the energy rates are determined pursuant to Exhibit A-4 to Rate Schedule A.

Also recognized in this Schedule B is that the energy available for sale to a PRM at the energy rates set forth in Rate Schedule A can from time to time be a function of operating characteristics and limitations associated with the AEPCO Resources.

In addition, this Schedule B specifies the methodology pursuant to which additional charges shall be made by AEPCO to a PRM in the event that: (1) a PRM requires energy from AEPCO Resources that is in excess of the energy available to the PRM associated with its AC in AEPCO Resources; or (2) a PRM does not take its required minimum capacity and energy from AEPCO Resources because the PRM has used energy from other sources that displaces the use of such minimum energy from AEPCO Resources. Such additional charges shall be billed to the PRM pursuant to Rate Schedule A.

2. 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" shall mean Allocated Capacity.

"AEPCO Federal Hydro Power Capacity" shall mean that amount of capacity on an hourly basis scheduled by AEPCO pursuant to Federal Hydro Power Agreements.

"AEPCO Minimum Base Capacity" shall mean the capacity from Available Base Capacity that must be operated from time to time to maintain system reliability or for other reasons, reflecting AEPCO's determination as to the schedule of energy from the Federal Hydro Power Agreements and AEPCO Minimum Coal Capacity.

"AEPCO Minimum Coal Capacity" shall mean the minimum output for safe and reliable operation of Apache Units 2 and 3.

"AEPCO Resource" shall mean a Resource owned or purchased from others by AEPCO.

"AEPCO Scheduling Portal" shall mean an internet web site maintained by AEPCO and accessible by all Class A Members for the purpose of AEPCO posting ongoing information relating to the availability and minimum must run requirements for AEPCO Resources.

"AEPCO Total Load" shall mean the aggregate of the demand requirements and the associated energy requirements of: (i) AEPCO Delivered Load plus, (ii) losses related thereto from the transmission of power and energy, plus, (iii) applicable only to the demand requirement computation: the greater of (a) applicable installed capacity margin, or (b) operating reserve requirements.

"Allocated Capacity" or "AC" shall mean the amount of capacity of AEPCO Resources from which a Partial Requirements Member is entitled to schedule energy in any month as set forth in its Partial Requirements Capacity and Energy Agreement. The AC for each month for the term of such agreement is set forth in Appendix B to Exhibit A-5 to Rate Schedule A of that agreement.

"Available Base Capacity" shall mean the energy from Base Resources, including Base Economy Purchases, available for dispatch in a Future Scheduling Hour, less losses in delivery to Class A Members, and excluding (i) any coal-fired capacity that is not available due to forced outage or scheduled maintenance outage or temporary deration, (ii) capacities of Power Sales Resources, and (iii) allocations for losses in delivery of such Power Sales Resources; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Base Capacity.

"Available Other Capacity" shall mean the amount of capacity that is available for dispatch as determined by AEPCO for any Future Scheduling Hour equal to the sum of (i) the aggregate of the capacities of Other Resources, which shall be as set forth in Appendix B to Exhibit A-5 of Rate Schedule A to each Partial Requirements Capacity and Energy Agreement, as may be amended, plus (ii) the capacity of any concurrent Replacement Purchases for Base Resources, less (iii) capacity set aside for Reserves and allocations for losses in delivery; and for each Billing Unit Entity, shall mean that Billing Unit Entity's ACP share of such Available Other Capacity.

"Available S&G PPA Capacity" shall mean S&G PPA Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an ACP in S&G PPA, shall mean that Billing Unit Entity's ACP share of such Available S&G PPA Capacity.

"Available Supplemental Capacity" shall mean Supplemental Capacity, less an allocation for losses for delivery, that is available for dispatch by AEPCO for any Future Scheduling Hour; and for each Billing Unit Entity having an interest in a Supplemental Purchase, shall mean that Billing Unit Entity's percentage share of such Available Supplemental Capacity.

"Base Capacity" shall mean for Base Resources the sum of (i) the capacity from Federal Hydro Power Agreements as adjusted to reflect seasonal and Peak Hours vs. Off-Peak Hours variations; plus (ii) 350 MW of capacity of AEPCO's coal-fired units.

"Base Economy Purchase" shall mean a purchase of energy by AEPCO from a third party, including wheeling charges recorded in RUS Uniform System of Accounts 565 Transmission of Electricity by Others or its successor for delivery of the purchase to an SWTC Point of Receipt, if any, which is made at a lower average energy rate over the purchase period than that associated with energy available from Base Resources during such period, and which AEPCO chooses to make in lieu of dispatching energy available from such Base Resources.

"Base Energy Cost" shall mean, for a billing period for each Billing Unit Entity, the sum of Remaining Base Energy Cost plus Base Transfer Sale Credits, Base Transfer Energy Cost, Base Economy Sales Credit and Base Economy Sales Cost for the same Billing Unit Entity.

"Base Resources" shall mean the Federal Hydro Power Agreements and two coal-fired steam Generating Resources that are Existing Resources located at the Apache Generating Station, in which each Class A Member has an ACP.

"Base Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by such Member* or its Scheduling Agent pertaining to the Member*'s use of its Available Base Capacity, as such Pre-Schedules and Real-Time Schedules are determined consistent with this Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Billing Unit Entity" shall mean any of CARM, a Member* or a Member* CA.

"CARM" or "Collective ARM" shall mean all of the All Requirements Members.

"CARM ACP" shall mean the sum of the ACPs in Existing Resources and in S&G PPA, as applicable to each All Requirements Member as set forth in Appendix A to Exhibit A-5 to Rate Schedule A to the ARM Wholesale Power Contracts.

"Class A Member" shall mean any entity which is or becomes such a Member of AEPCO, TRANSCO or CSP under the relevant cooperative's By-laws.

"Cost Causation" shall mean the identification of all direct and indirect costs, revenue and billing units associated with individual Resources and services, such that costs, revenue and billing units can be accounted for and billed separately to the specific Class A Members participating in such Resource or receiving such service.

"Directed Sales" shall mean any transactions in which, at the advance direction of a Member* CA, AEPCO for such Member* CA's benefit sells to a third party at wholesale energy from such Member* CA's available AEPCO Resources.

"Dispatch Pool Resources" shall mean Existing Resources, the S&G PPA and Supplemental Purchases.

"Existing Resource(s)" shall mean the AEPCO Resource(s) as set forth and designated as Existing Resources in Appendix B to Exhibit A-5 to Rate Schedule A, consisting of Base Resource(s) and Other Resource(s).

"Federal Hydro Power Agreement(s)" shall mean 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 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).

"FPPCA" shall mean Fuel and Purchase Power Cost Adjustor determined for the applicable AEPCO Resources.

"FPPCA Period" shall mean the period of months over which AEPCO is to record S&G PPA Energy Charge, Supplemental Purchase Cost, Base Energy Cost and Other Energy Cost for billing or credit to the Class A Members pursuant to the Tariff.

"Future Scheduling Hour" shall mean a clock hour beginning more than sixty (60) minutes after the current hour.

"Intra-Day Schedule" shall mean a Real-Time Schedule.

"Member*" shall mean a PRM whose load is not assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Member* CA" shall mean a PRM whose load is assigned to the SWTC metered subsystem of the Western Area Lower Colorado Balancing Authority in the Desert Southwest Region.

"Minimum Other Capacity" shall mean the capacity from Available Other Capacity that must be operated from time to time to maintain system reliability or for other reasons as described in Section 4.2 of Schedule B to the Partial Requirements Capacity and Energy Agreements.

"Other Resources" shall mean all gas-fired combustion turbine and gas-fired steam Generating Resources that are Existing Resources located at Apache Generating Station, in which each Class A Member has an ACP, which include GT-1, Steam 1, GT-2, GT-3 and GT-4.

"Other Schedule" shall mean, for each Member*, its Pre-Schedules and Real-Time Schedules provided to AEPCO by Member*'s Scheduling Agent pertaining to such Member*'s use of its Available Other Capacity and, separately identified, of its Available S&G PPA Capacity, if any, as such Pre-Schedules and Real-Time Schedules are determined consistent with this Schedule B.

"Partial Requirements Member" shall mean MEC, SSVEC, TRICO or any other Class A Member of AEPCO that executes and delivers a Partial Requirements Capacity and Energy Agreement.

"Power Sales Resource" shall mean a sale of capacity and energy from Existing Resources made by AEPCO with a contract term greater than one year (other than sales to Class A Members pursuant to a Wholesale Power Contract and the Partial Requirements Capacity and Energy Agreement) including sales to Class B and Class C Members of AEPCO.

"Pre-Schedule" shall mean a Schedule submitted by a Scheduling Agent to AEPCO for the use of Resources for the following Scheduling Day as defined by WECC.

"Pre-Schedule Day" shall mean the day on which a Pre-Schedule must be submitted for the next Scheduling Day.

"PRM" shall mean a Partial Requirements Member.

"Real-Time Schedule" shall mean any Schedule submitted by a Scheduling Agent to AEPCO that changes a previously submitted Tag or that requires a new Tag to be created for a Future Scheduling Hour of the current operating day.

"Replacement Purchase" shall mean any purchase of energy made to replace energy that is not available from any AEPCO Resource due to forced outage, scheduled outage or deration of such AEPCO Resource.

"S&G PPA" shall mean either or both of the following purchase power agreements: (i) the Confirmation Agreement dated August 17, 2004, between AEPCO and South Point Energy Center, LLC (South Point), by which AEPCO purchases between 25 MW and 55 MW of electric capacity and associated energy in Daylight Hours of May through October of each year from 2008 through 2014; and (ii) the Confirmation Agreement dated August 19, 2004, between AEPCO and Griffith Energy, LLC, as currently assigned pursuant to Assignment and Consent Agreement dated March 14, 2008, by which AEPCO purchases 25 MW of electric capacity and associated energy in WECC Peak Hours of May through October of each year from 2008 through 2014.

"S&G PPA Capacity" shall mean capacity from S&G PPA.

"S&G PPA Schedule" shall mean for a Member* with an ACP in S&G PPA, its Pre-Schedules and Real-Time Schedules provided to AEPCO by its Scheduling Agent pertaining to its use of its Available S&G PPA Capacity.

"Schedule" shall mean, for each Member*, any of its Base Schedule, its Other Schedule, and, if applicable, its S&G PPA Schedule.

"Scheduled Day" shall mean the Scheduling Day, as defined by WECC, for which a Pre-Schedule has been submitted.

"Scheduling Agent" shall mean the entity designated by a Member* to provide Pre-Schedules and Real Time Schedules to AEPCO for such Member*'s hourly use of its AC in AEPCO Resources.

"Supplemental Capacity" shall mean capacity from Supplemental Purchase.

"Supplemental Purchase" shall mean, in a billing period, any purchase of firm energy made by AEPCO for a period of less than a year to serve load of CARM or a Member* CA as a Planning Contract Member in excess of CARM's or such Planning Contract Member's ACP shares of capacities of S&G PPA and Existing Resources.

"Tag" shall mean the collection of information in the electronic form of request and subsequent response as part of the process implemented by the North American Electric Reliability Corporation for electronically communicating a request for, securing approval of, and recording an energy transaction via the Internet.

3. <u>AEPCO RESOURCE AVAILABILITY</u>

3.1 <u>Available Base Capacity</u>.

AEPCO shall continuously notify each Scheduling Agent of Available Base Capacity by posting such information to the AEPCO Scheduling Portal. On a day-ahead and hourly basis, AEPCO will post Available Base Capacity reflecting AEPCO's determination as to the schedule of the hydropower plus available coal capacity. A Member* shall create its Base Schedules using its ACP share of Available Base Capacity as posted to the AEPCO Scheduling Portal.

3.2 <u>Available Other Capacity</u>.

A Member* shall create its Other Schedule of energy from its ACP share of Available Other Capacity, which may be an amount up to the difference obtained by subtracting the Member*'s ACP share of Available Base Capacity for each hour from such Member*'s AC in AEPCO Resources.

3.2.1 Once a Member* has submitted a Pre-Schedule of its Other Schedule, the Member* may not decrease such Other Schedule on an intraday basis (*i.e.* during the Scheduled Day for which the Other Schedule applies); provided, however, that in the event that a Member* experiences an unforeseen downward deviation in Native Load as compared to what was reasonably forecasted in its Pre-Schedule, such Member* shall first decrease to the extent possible its schedule from Member* Resources, and then may decrease its Other Schedule by means of an Intraday Schedule.

3.2.2 In the event that a Member* decreases an Other Schedule by means of an Intraday Schedule, the Member* shall provide to AEPCO by noon of the second subsequent Business Day evidence showing that Member*'s Native Load was, in fact, less than was reasonably forecasted in the Other Schedule. If AEPCO rejects such evidence, the Member* shall be billed

as if such Other Schedule were not decreased, and the Member* shall pay the amount billed, and may dispute its payment pursuant to the Dispute Resolution provisions of its Agreement.

3.3 Available S&G PPA Capacity.

On a day-to-day basis, AEPCO will post to the AEPCO Scheduling Portal the available capacity and the hours of each day in which AEPCO is obligated to take such capacity if scheduled, for each of the purchase power agreements which make up Available S&G PPA Capacity. A Member* shall create its S&G PPA Schedule using 100% of its ACP share of available capacity from either or both purchase power agreements of Available S&G PPA Capacity, for all the hours of the scheduling day for which AEPCO is obligated to schedule capacity from each such purchase power agreement.

3.5 Obligations of the Parties for the Period Beyond January 1, 2021.

Beginning January 1, 2021, a PRM's AC shall be reduced to reflect the effective retirement of certain Other Resources. To the extent that such retirement reduces Available Other Capacity such that a PRM's Available Other Capacity is available only as reserve capacity, the provisions of Sections 3.2. and 4.2 shall no longer be of any force or effect. In addition, a PRM's Available Base Capacity may be reduced in the event AEPCO must use Available Base Capacity to meet operating reserve requirements, unless the PRM and AEPCO agree that operating reserves may be supplied from another source.

4. MINIMUM CAPACITY REQUIREMENTS:

4.1 Minimum Base Capacity Requirements.

On a day-to-day basis, AEPCO will post to the AEPCO Scheduling Portal Minimum Base Capacity reflecting AEPCO's discretion as to the schedule of energy from the Federal Hydro Power Agreements and Minimum Coal Capacity. A Member* shall schedule and a Member* CA shall take energy available from its AC in AEPCO Resources in an hour in an amount no less than its share of AEPCO Minimum Base Capacity. A Billing Unit Entity's share of AEPCO Minimum Base Capacity shall be the product of its ACP multiplied by AEPCO Minimum Base Capacity for that hour. If a Billing Unit Entity fails to takes its Minimum Base Capacity, AEPCO shall charge a Minimum Base Capacity Charge, as applicable, either pursuant to Section 6.2.1 of this Schedule B for a PRM or pursuant to Section 2.4 of its Rate Schedule A for an ARM.

4.2 Minimum Other Capacity Requirements.

From time to time, AEPCO may be required to generate out of merit order energy from Other Resources for such reasons as: to respond to transmission constraints, to maintain reliability in certain peak periods of the year, to support generation needs in the event of an outage of a Base Resource, or to consume scheduled

natural gas deliveries in the event natural gas storage cannot be utilized. As Minimum Other Capacity is determined, AEPCO will post to the AEPCO Scheduling Portal the nature, amount, and deration of Minimum Other Capacity as in effect from hour to hour. A Member* must schedule and a Member* CA must take energy available from its Available Other Capacity in an hour in an amount no less than its share of Minimum Other Capacity. For each hour of each month, a Billing Unit Entity's share of AEPCO Minimum Other Capacity shall be the product of its ACP multiplied by AEPCO Minimum Other Capacity. If a Billing Unit Entity fails to takes its Minimum Other Capacity, AEPCO shall charge a Minimum Other Capacity Charge, as applicable, either pursuant to Section 6.2.1 of this Schedule B for a PRM or pursuant to Section 2.4 of its Rate Schedule A for an ARM.

4.3 Minimum S&G PPA Capacity.

AEPCO will dispatch, account for, and bill the costs of Available S&G PPA Capacity in accordance with one or more applicable agreements between AEPCO and all Class A Members with an ACP in S&G PPA. Schedules submitted by Members to AEPCO for the use of Available S&G PPA Capacity will comport with the actual dispatch limitations and requirements of the S&G PPA.

In each hour, a Billing Unit Entity shall be responsible for taking and paying for its ACP share, if any, of energy from S&G PPA Capacity as dispatched by AEPCO.

5. SCHEDULING:

5.1 General Scheduling Concepts.

This section establishes a framework for scheduling AEPCO Resources consistent with cost causation principles. A Member* shall submit separate Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, to AEPCO. Schedules submitted by Member*s shall not dictate physical dispatch, except in the case of the S&G PPA. AEPCO shall retain full generation control, develop forecasts of resource requirements, and dispatch the resources at its disposal using traditional economic stacking principles.

5.2 Scheduling Agent.

A Member* shall designate itself or a third party as Scheduling Agent to compute and provide to AEPCO Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, for use of energy from its AC in AEPCO Resources. The Member* shall bind its Scheduling Agent to abide by the confidentiality provisions of this Agreement in order to prohibit sharing of AEPCO Resource costs and availability information with others.

5.3 Member* Schedules.

The Scheduling Agent shall develop Base Schedules, Other Schedules, and, if applicable, S&G PPA Schedules, pursuant to this Section 5 and Exhibit B-1 hereof. Scheduling Agent shall submit such Schedules to AEPCO in accordance with the timetables outlined in Exhibit B-1 hereof.

5.4 Scheduling Limitations.

Schedules may be limited in accordance with the following.

5.4.1 Scheduling Limits during Base Resource Outage or Reduction.

AEPCO will notify the Scheduling Agents as soon as practicable after the outage or reduction of a Base Resource.

For so long as AEPCO is a member of the Southwest Reserve Sharing Group or its successor (SRSG), the following time frames shall apply for scheduling in response to an outage or reduction of a Base Resource:

(a) Initial Sixty (60) Minute Period - The replacement energy for the first sixty (60) minutes following notification of the loss to the SRSG parties will be provided to AEPCO pursuant to the SRSG Agreement, and Schedules need not be adjusted for such initial sixty (60) minutes.

(b) After the Initial Sixty (60) Minute Period - The Scheduling Agent shall reduce the Member*'s Base Schedule by the Member*'s share of the lost capacity beginning at sixty (60) minutes following AEPCO's notification of the outage to the SRSG parties. In such event, the Scheduling Agent may increase its Other Schedule to replace the lost capacity; otherwise, such capacity will be replaced by AEPCO. Within ten (10) minutes of notification of a Base Resource outage or reduction, Scheduling Agent must notify AEPCO if Member* does not want to increase its Other Schedule after such sixty (60) minute period to replace the lost capacity; unless AEPCO receives such notice within such ten (10) minutes, AEPCO will replace the lost capacity. Any otherwise applicable requirements of Exhibit B-1 that set timeframes for notice will not apply in such event.

If the SRSG Agreement is terminated or AEPCO is otherwise no longer a member of SRSG, the Parties agree to diligently work to determine how the capacity will be replaced in case a Base Resource experiences an outage or reduction.

5.4.2 Scheduling Limits during Other Resource Outage.

In the event an outage or de-ration of an Other Resource occurs, AEPCO shall post notice of such event to the AEPCO Scheduling Portal and replace the reduced capacity of the Other Resource, and Scheduling Agent may but shall not be required to alter Member*'s Other Schedule. Within ten (10) minutes of notification of an Other Resource outage or reduction, Scheduling Agent must notify AEPCO if Member* plans to alter its Other Schedule; unless AEPCO receives such notice within such ten (10) minutes, AEPCO will replace the lost capacity. Any otherwise applicable requirements of Exhibit B-1 that set timeframes for notice will not apply in such event.

5.4.3 Overscheduling.

5.4.3.1 If a Scheduling Agent submits a Base Schedule in an amount that exceeds the Member*'s Available Base Capacity, the amount in excess of Member*'s Available Base Capacity will become part of the Member*'s Other Schedule for the purposes of the energy accounting of the Billing Unit Program of Exhibit A-4.

5.4.3.2 If a Scheduling Agent submits Schedules that collectively exceed the Member*'s AC for an hour, AEPCO is not obligated to provide the amount above AC, provided, however, that if AEPCO does not seek to have Member* correct such Schedules, Member* shall be subject to a penalty, calculated in accordance with Section 6.2.2.

5.5 AEPCO Scheduling Responsibilities.

5.5.1 AEPCO shall communicate by posting to the AEPCO Scheduling Portal all information required in accordance with this Section 5.5 and Exhibit B-1 hereof. Using the AEPCO Scheduling Portal, AEPCO shall publish and update Available Base Capacity, Available Other Capacity, and Available S&G PPA Capacity, all on a real time basis. In addition, AEPCO will contact and notify Scheduling Agents as soon as practicable when units become unavailable and/or are derated, and when units return to service, in whole or in part.

5.5.2 AEPCO shall be responsible for scheduling and dispatching AEPCO Resources on an economic basis to meet CARM load requirements, Member* CA load requirements, and Member* Schedules.

5.5.3 AEPCO shall make Replacement Purchases as necessary to meet load requirements and Schedules due to outages of AEPCO Resources.

5.6 Unit Limitations.

AEPCO shall maintain Resource Operation and Unit Dispatch Practices, attached hereto as Exhibit B-2 and made a part hereof, that among other things establish

limitations on the dispatching of AEPCO Resources and consequently provide a basis for AEPCO to make Other Economy Purchases and Replacement Purchases.

6. ADDITIONAL CHARGES:

6.1 Ordinary Service.

Unless otherwise provided in this Schedule B, the energy sold by AEPCO to a PRM pursuant to the Agreement shall be at the rates and charges set forth in Exhibit A-1 to Rate Schedule A to their respective Agreements.

6.2 Additional Charges.

In addition to the rates and charges set forth in Exhibit A-1 to Rate Schedule A, a PRM shall pay AEPCO the following additional amounts resulting from this Schedule B.

6.2.1 Capacity and Energy Below AC.

If a PRM is utilizing a Member* Resource, Future Resource, S&G PPA, or Supplemental Purchase in any hour to serve Native Load and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of AEPCO Minimum Base Capacity or Minimum Other Capacity, it shall pay a charge as set forth in this Section 6.2.1.

6.2.1.1 PRM Minimum Base Capacity Charge - In the event that a PRM has replaced its use of AEPCO Resources with a Member Resource, Future Resource, S&G PPA or Supplemental Purchase to serve Native Load in any hour and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of Minimum Base Capacity, AEPCO shall charge and the PRM shall pay a charge in an amount obtained by multiplying the lesser of (i) the amount of Member Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour, or (ii) the amount of the PRM's pro rata share of all PRMs' collective deficiency in their combined shares of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 to Rate Schedule A and as determined for the billing period. Member shall only be subject to PRM Minimum Base Capacity Charge to the extent that Available Base Capacity dispatched for Class A Members as a whole is below Minimum Base Capacity.

6.2.1.2 PRM Minimum Other Capacity Charge - In the event that a PRM has replaced its use of AEPCO Resources with a Member Resource, Future Resource, S&G PPA or Supplemental Purchase to serve Native Load in any hour and fails to schedule or utilize energy from AEPCO Resources sufficient to meet its share of AEPCO Minimum Other Capacity, AEPCO shall charge and the

PRM shall pay an amount obtained by multiplying the lesser of (i) the amount of Member Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour, or (ii) the amount of the PRM's pro rata share of all PRMs' collective deficiency in their combined share of Minimum Other Capacity in such hour, by the Gas Energy Rate as defined in Exhibit A-4 to Rate Schedule A and as determined for the billing period.

6.2.1.3 In the event that in any hour both Sections 6.2.1.1 and 6.1.1.2 would apply, the PRM Minimum Other Capacity Charge will be determined first as set forth in Section 6.2.1.2 above, and the associated PRM Minimum Base Capacity Charge shall be an amount obtained by multiplying the lesser of (i) the amount of Member* Resource, Future Resource, S&G PPA or Supplemental Purchase used in such hour less the amount of energy used as the basis for the PRM Minimum Other Capacity Charge, or (ii) the amount of the PRM's deficiency in its share of Minimum Base Capacity in such hour, by the Coal Energy Rate as defined in Exhibit A-4 of Rate Schedule A and as determined for the billing period.

6.2.2 Capacity and Energy Above AC.

In each month in which a Class A Member's use of AEPCO Resources exceeds its AC, AEPCO shall charge the Class A Member an amount equal to the Demand Overrun Adjustment as calculated in Section 2.3 of Rate Schedule A, and the Class A Member shall also pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Energy Rate.

7. REVISIONS TO EXHIBITS:

From time to time events will occur which will necessitate the revision of the Exhibits attached to this Schedule B. Except when such Exhibits specifically provide for updates by specific parties, such revisions shall only be made pursuant to mutual agreement of AEPCO and all PRMs.

EXHIBIT B-1

Merchant Scheduling Practices and Procedures

1. FOR MEMBERS* OUTSIDE THE AEPCO PSEUDO BALANCING AREA:

1.1 Introduction.

1.1.1 Prior to each Scheduled Day, the Scheduling Agent will provide Pre-Schedules identifying anticipated Base Schedules and Other Schedules for the Scheduling Day, as defined by WECC, by hour, to AEPCO. AEPCO may commit to natural gas purchases when Other Resources have been Pre-Scheduled.

1.1.2 On the Scheduled Day, the Scheduling Agent may submit Real-Time Schedules adjusting Base Schedules within the ramping and other operating limitations of the Base Resources located at the Apache Generating Station. Real-Time Schedules may be submitted to adjust Other Schedules in accordance with Section 3.2.1 and within the ramping and other operating limitations of the Other Resources located at the Apache Generating Station; such Real-Time Schedules adjusting Other Schedules will only be accommodated to the extent they can be coordinated with fuel scheduling adjustments. (See the operating day gas unit limitations outlined in the PRM load control transfer agreements.) All Real-Time Schedules must be submitted no later than seventy (70) minutes prior to the hour power is to flow.

1.1.3 AEPCO may be able to make exceptions and accommodate Real-Time Schedules that would require AEPCO to ramp at a faster rate than under normal operating levels when such adjustments are needed to deal with emergency situations; such requests will be dealt with case-by-case.

1.2 Pre-Schedules.

1.2.1 Scheduling Agent shall submit Member*'s preliminary estimated Pre-Schedules to AEPCO pre-schedulers by 1600 MST of the day prior to Scheduling Day as defined by WECC. The Pre-Schedules shall separately identify Base Schedules and Other Schedules. Preliminary Pre-Schedules may be submitted by phone, fax or e-mail.

1.2.2 Scheduling Agent shall submit Member*'s final Pre-Schedules to AEPCO pre-schedulers by 0630 MST of the Pre-Schedule Day. The Pre-Schedules shall separately identify Base Schedules and Other Schedules. Final Pre-Schedules may be submitted by phone, fax or e-mail.

1.2.3 Scheduling Agent is responsible for generating tags in accordance with WECC time-lines and procedures. AEPCO, as mutually agreed, may generate tags on behalf of the Scheduling Agent.

1.3 Day of Scheduling.

1.3.1 Real-Time Schedules must be provided to AEPCO at least seventy (70) minutes prior to the hour the Schedule is to flow.

1.3.2 Scheduling Agent is responsible for creating or modifying tags in accordance with WECC time-lines and procedures. AEPCO, as mutually agreed, may create tags on behalf of the Scheduling Agent.

1.3.3 In the event AEPCO chooses to modify the source of a Base Schedule or Other Schedule from its originally tagged source, AEPCO will be responsible for creating the tags associated with the modified source such Schedule. Upon notice from AEPCO no later than forty (40) minutes in advance of the hour, Scheduling Agent shall adjust any of the original tags to accommodate the new tag created by AEPCO, per AEPCO's direction.

1.4 Information Supplied by AEPCO Real Time.

1.4.1 Planned generating unit maintenance schedules.
1.4.2 Planned and unplanned full or partial generating unit outages.
1.4.3 AEPCO Minimum Base Capacity and AEPCO Minimum Other Capacity.

1.5 Emergency scheduling.

1.5.1 Schedules which do not meet the requirements in this Section 1 may be accepted by AEPCO subject to the agreement of all affected parties in the transaction.

1.6 Procedure for Rounding Tenths of MW to Whole MWs.

Initially, AEPCO will report hourly values for AC and for shares of Available Base Capacity, of AEPCO Minimum Base Capacity and of Minimum Other Capacity in tenths of a MW. To facilitate the industry standard of the scheduling of energy in whole MWs, values of hourly AC and shares of Available Base Capacity, of AEPCO Minimum Base Capacity and of Minimum Other Capacity in tenths of a MW shall be rounded down to whole MWs. Values for the hourly share of Available Other Capacity shall then be obtained by subtracting such rounded down share of Available Base Capacity from such rounded down AC for the same hour.

1.7 Intra Day Schedule Change Requiring Gas Generation.

1.7.1 As of early 2010, gas turbine minimum loading, run times and start-up cost is as follows. Applicable updates to this information shall be provided from time to time by AEPCO to Scheduling Agents.

1.7.1.1 Combine Cycle (82 MW): Minimum run time is monthly with a minimum loading of 20 MW every hour. Start-up is $4,469

1.7.1.2 Steam Unit #1 (72 MW): Minimum run time is monthly with a minimum loading of 20 MW every hour. Start-up is $4,469

1.7.1.3 Gas Turbine #1 (10 MW): Minimum run time is four (4) hours with a minimum loading of 2 MW every hour. Start-up is $1,817

1.7.1.4 Gas Turbine #2 (20 MW): Minimum run time is four (4) hours with a minimum loading of 2 MW every hour. Start-up is $1,646

1.7.1.5 Gas Turbine #3 (65 MW): Minimum run time is six (6) hours with a minimum loading of 5 MW every hour. Start-up is $1,514

1.7.1.6 Gas Turbine #4 (38 MW): Minimum run time is two (2) hours with a minimum loading of 10 MW every hour. Start-up is $ (to be provided by AEPCO)

1.7.2 El Paso Gas Scheduling Times.

1.7.2.1 Introduction.

The following closing times for each gas scheduling cycle are provided to assist Scheduling Agent when submitting Other Schedules. AEPCO requires at least a one (1) hour notice prior to such closing times in order to purchase gas from suppliers and to schedule the gas by means of El Paso's software. If there is any change to applicable closing times, AEPCO shall provide Scheduling Agents updates of such times.

1.7.2.2 Winter (Nov-Mar).
Pre-Schedule Day
Cycle 1: 0730 MST
Cycle 2: 1530 MST

Day of Flow
Cycle 3: 0930 MST
Cycle 4: 1300 MST

1.7.2.3 Summer (Apr-Oct).
Pre-Schedule Day
Cycle 1: 0630 MST
Cycle 2: 1430 MST

Day of Flow
Cycle 3: 0830 MST
Cycle 4: 1200 MST

1.8 After-the-Fact Check-Outs.

1.8.1 Mid-month - AEPCO and Scheduling Agent shall perform a mid-month check-out approximately on the 15th of each month. Check-out should include Base Schedules and Other Schedules.

1.8.2 Monthly - AEPCO and Scheduling Agent shall perform a month end check-out of schedule flow as soon as possible after the end of each month, but no later than four (4) working days after end of the month.

1.9 AEPCO Contacts.

The following contact information may be updated by AEPCO or a PRM, as applicable, at any time by providing notice to all contacts listed at the time for all other entities.

1.9.1 AEPCO Pre-Schedule Contacts

i Ron Goodman
(520) 586-5276
(520) 586-5445 Facsimile
rgoodman@aepco.coop

ii. Daniel Unrast
(520) 586-5528
(520) 586-5445 Facsimile
dunrast@aepco.coop

E-mails relating to Pre-Schedules shall be sent to all persons listed above.

1.9.2 AEPCO Real-Time Schedule Contacts

i Traders
(520) 586-5407
(520) 586-5445 fax
traders@aepco.coop

1.10 PRM Scheduling Agent Contacts.

1.10.1 PRM Scheduling Agent Pre-Schedule Contacts

i Penny Casey
(602) 605-2585
(602) 605-2831 facsimile
Casey@wapa.gov

i Tim Alme
(602) 605-2854
(602) 605-2831 facsimile

1.10.2 PRM Scheduling Agent Real-time Schedule Contacts

i On-Call Scheduler
(602) 605-2666
(602) 605-2831 fax

1.11 Contacts for After-the Fact Check-Outs.

1.11.1 AEPCO

i Ron Goodman
(520) 586-5276
(520) 586-5445 Facsimile
rgoodman@aepco.coop

ii. Daniel Unrast
(520) 586-5228
(520) 586-5445
dunrast@aepco.coop

1.11.2 PRM Scheduling Agent Contacts for After-the-Fact Check-Outs

i ??????????
(602) 605-2675
(602) 605-2490 facsimile

ii John Paulsen
(602) 605-2557
(602) 605-2831 facsimile

2. FOR MEMBER* CAS INSIDE THE AEPCO PSEUDO BALANCING AREA:

A Member* CA shall execute a Scheduling, Accounting and Reporting Services Agreement with AEPCO, which agreement shall identify any applicable scheduling practices or procedures, including procedures by which Member* CA can direct AEPCO to sell for Member* CA's benefit a specified amount of the energy to which Member* CA is entitled.

EXHIBIT B-2

AEPCO's Resource Operation & Unit Dispatch Practices

1. INTRODUCTION:

These Resource Operation & Dispatch Guidelines set forth the practices that AEPCO shall follow in: (a) operating AEPCO Resources, including the AC of the Partial Requirements Members and sales from AEPCO Resources, when: (i) Pre-Scheduling such Resources for dispatch by AEPCO on a least cost basis; (ii) placing such Resources out of service for planned or forced maintenance; (iii) making Third Party Economy Sales from such Resources and making Non-Base Economy Purchases against such Resources; (iv) purchasing for sale; (v) making power sales from such Resources; (vi) accounting for energy uses and costs; (vii) billing and collecting from third parties for capacity and/or energy sales, purchases, transmission and other services; and (viii) complying with regulatory requirements of Governmental Authorities having jurisdiction, all in accordance with the provisions of this Agreement.

2. AEPCO RESOURCE PRE-SCHEDULE PRACTICES:

AEPCO shall perform Resource pre-scheduling as follows:

2.1. Establishing Pre-schedules - AEPCO shall develop Resource Pre-Schedules in advance for each hour of the subsequent operating day(s) through midnight of the next working day in accordance with principles of least-cost dispatch of AEPCO Resources to the extent practicable. AEPCO shall submit such Pre-Schedules to TRANSCO for its implementation as required by TRANSCO. Pre-schedules shall specify sufficient Resources to serve forecast hourly AEPCO Delivered Load plus the Pre-Scheduled Energy requirements for delivery losses related to AEPCO Delivered Load. Pre-Schedules shall additionally provide AEPCO Resources on-line and operating in an unloaded state sufficient to provide Operating Reserves - Spinning Reserves and for Regulation and Frequency Response Service, both as required for AEPCO Delivered Load. Pre-Schedules shall additionally consider AEPCO provisions for unloaded and off-line generating capacity and/or interruptible load sufficient to provide for Operating Reserve - Supplemental as required for AEPCO Delivered Load. All AEPCO Resources shall be Pre-Scheduled to dispatch resources of lowest operating cost first. AEPCO shall coordinate with and provide Pre-Schedule information to all suppliers and transmitters of the AEPCO Resources involved in the Pre-Schedule. All Pre-Schedules shall be prepared with consideration for the following parameters:

2.1.1. Generator operating constraints such as minimum and maximum loading levels, ramp rates, minimum run times, maximum run times, system stability requirements (e.g., voltage support or VAR support), operating reserve requirements, planned outages, environmental compliance and any other constraint or condition affecting generation;

2.1.2. Generating unit testing requirements in accordance with Prudent Utility Practice;

2.1.3. Firm purchase contract conditions such as minimum and maximum load factors, minimum or maximum Energy take requirements, and any other constraint or condition affecting the ability to receive Capacity or Energy under the contract;

2.1.4. Generating unit outages which would limit a supplier's ability to deliver Capacity or Energy pursuant to a purchase contract;

2.1.5. The availability of Non-Base Economy Purchases from market suppliers, and the opportunity to make Third Party Economy Sales at the current market price; and

2.1.6. Transmission constraints or limitations and transmission service contract requirements which would preclude the physical delivery of Energy as contemplated by the Pre-Schedule, including loss factors.

2.2 Resource Revisions to Pre-Schedules.

Resource Pre-Schedules may be revised by AEPCO in advance of any hour to recognize changes in load requirements, generator conditions, transmission outages, market opportunities and such other needs as may occur throughout the day. AEPCO's primary purpose in making such revisions shall be to keep sufficient AEPCO Resources on-line at all times to reliably serve AEPCO Total Load. A secondary purpose shall be to reduce overall operating costs of AEPCO Resources.

3. REGULATORY REQUIREMENTS:

AEPCO shall comply with regulatory requirements of all Governmental Authorities having jurisdiction as such requirements may apply with respect to these Resource Operation and Unit Dispatch Guidelines. In the event of any conflict between such regulatory requirements and these Guidelines, such regulatory requirement shall govern.

4. AEPCO COMMITMENT GUIDELINES FOR OTHER RESOURCES:

The following unit commitment guidelines relate to the start-up and operation of Other Resources. These are intended to recognize Other Resources operation limits in order to preserve their lives and reduce the likelihood of experiencing renovation and/or extraordinary maintenance costs prior to their anticipated retirement at the end of 2020. These guidelines do not prohibit AEPCO from buying from the market in lieu of starting and operating these units at any time. The guidelines shall be as follows:

4.1 For peaking GT Units 1 and 3: These units shall be reserved for dispatch basically in super-peak hours (HE 1200 through HE 2000) in summer months of June through September (exception: GT-1 when used with Steam 1 in CC operation)

4.1.1 No nighttime commitment (off-peak hours Monday through Saturday, Sunday HE 2300 – HE 0700).

4.1.2 No winter commitment except if necessary to cover superpeak daytime periods during base load unit maintenance outages.

4.2 For peaking GT Unit 2: This unit shall not be operated and shall be held in reserve for meeting 20 MW of AEPCO's non-spinning reserve requirements, but may be started and dispatched as called upon to fulfill reserve obligations.

4.3 For peaking GT Unit 4: This unit shall be available for operation in Peak Hours and Sunday HE 0800 through HE 2200 throughout the summer period, in winter peak months (December, January), and during coal unit Existing Resource maintenance or forced outages. When operating, a portion of its Capacity as needed shall be set aside for supplementing the Spinning Reserves supplied from coal-fired Existing Resources.

4.4 For Steam 1 (in CC or not): This unit shall be available in the summer period (May through October) for daily operation around the clock as may be required to preserve load serving capability and backup to forced outage of coal-fired Existing Resources. Winter period use is permitted during coal unit maintenance outage periods and during winter peak months of December and January, but every effort should be made to utilize market purchases prior to committing the unit in winter months.

5 GUIDELINES FOR AEPCO PURCHASES AND SALES:

5.1 Maintenance Purchases.

In the event an AEPCO Resource is out of service for planned maintenance or otherwise has been taken off-line and a Replacement Purchase is needed to meet AEPCO Total Load, AEPCO may locate and contract for the replacement of such AEPCO Resource for the expected deration of the Resource outage.

5.2 Economy Sales and Economy Purchases.

5.2.1 General.

AEPCO shall at all times be cognizant of the opportunities to make and shall make appropriate Third Party Economy Sales from AEPCO Resources (with the exception of power purchased under Federal Hydro Power Agreements) and Non-Base Economy Purchases against AEPCO Resources to realize the optimum cost of Resources in the Pre-Schedule for serving AEPCO Delivered Load. Any single such Third Party Economy Sale and any single such Non-Base Economy Purchase shall not extend beyond the subsequent twelve calendar months nor exceed duration of

twelve (12) consecutive months, and otherwise shall be made in accordance with the following:

5.2.2 Economy Sales.

At any time that Capacity and Energy from an AEPCO Resource is available for sale and can be sold without jeopardizing system reliability and taking into consideration the factors governing such Resource as set forth in Section 2.1 above, AEPCO may Pre-Schedule such a sale. The price related to such Economy Sale shall exceed such Resource's marginal cost (including appropriate allowances for fixed and variable costs as determined by AEPCO from time to time) plus transmission service and ancillary services costs and losses, as applicable (Resource Cost).

5.2.3 Dump Energy Sales.

At any time that an AEPCO Resource must be maintained online for testing or for meeting subsequent hours' loads and is not otherwise needed to serve current loads, AEPCO may sell the energy surplus of such Resource as dump energy at the prevailing market price without regard to such Resource's Resource Cost.

5.2.4 Non-Base Economy Purchases.

AEPCO may Pre-Schedule a Non-Base Economy Purchase at any time an AEPCO Resource that is (i) currently being dispatched, (ii) can be taken and remain off line for the purchase period without jeopardizing system reliability, and (iii) will be replaced with a capacity or energy purchase at a price lower than its Resource Cost.

5.3 Energy Purchase for Sale.

AEPCO may from time to time enter into purchases of energy at wholesale from third party suppliers to substitute for Resources that could otherwise be dispatched (or as a temporary replacement for Resources out of service as an alternative to interrupting the sale) to support sales at wholesale from AEPCO Resources (Purchases for Sale), subject to the following:

5.3.1 The Resource Cost of such purchases plus the cost of other Resources being used to make the sale (including delivery costs and losses) shall be less than the price received from the sale;

5.3.2 Such Purchases for Sale shall not increase the operating reserve requirements or otherwise increase costs to AEPCO unless such costs are recovered in the sale price; and (iii) such purchase shall be for a deration of no greater than the deration of the sale which it supports.

EXHIBIT D

Exhibit D

Arizona Electric Power Cooperative, Inc.
Summary of Revised Proposed Rates
TRICO PRM Case
Docket No. E-01773A-09-0472

	Proposed Rates Amended Filing - 4/20/2010 TRICO as ARM				Revised Proposed Rates TRICO as PRM			
All-Requirements Members:								
Fixed Charge		862,343	/Month (1)		$	232,978	/Month (1)	
O&M Charge		1,229,653	/Month (1)		$	436,144	/Month (1)	
Energy Rates:								
Base Resources	$	0.03236	/kWh		$	0.03157	/kWh	
Other Resources	$	0.06746	/kWh		$	0.06069	/kWh	
Energy Rate	$	0.03722	/kWh	(Average)	$	0.03276	/kWh	(Average)
Partial-Requirements Members:								
Mohave Electric Cooperative:								
Fixed Charge	$	709,721	/Month		$	709,721	/Month	
O&M Charge	$	1,323,724	/Month		$	1,323,724	/Month	
Energy Rates:								
Base Resources	$	0.03216	/kWh		$	0.03216	/kWh	
Other Existing Resources	$	0.06879	/kWh		$	0.06879	/kWh	
Energy Rate	$	0.03595	/kWh	(Average)	$	0.03595	/kWh	(Average)
Sulphur Springs Valley Electric Cooperative:								
Fixed Charge	$	628,440	/Month		$	628,440	/Month	
O&M Charge	$	1,172,125	/Month		$	1,172,125	/Month	
Energy Rates:								
Base Resources	$	0.03230	/kWh		$	0.03230	/kWh	
Other Existing Resources	$	0.06676	/kWh		$	0.06676	/kWh	
Energy Rate	$	0.03672	/kWh	(Average)	$	0.03672	/kWh	(Average)
Trico Electric Cooperative:								
Fixed Charge	(Rates as stated above for				$	629,365	/Month	
O&M Charge	All-Requirements Members)				$	793,509	/Month	
Energy Rates:								
Base Resources					$	0.03240	/kWh	
Other Existing Resources					$	0.06612	/kWh	
Energy Rate					$	0.03885	/kWh	(Average)

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