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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY) DOCKET NO. E-01933A-98-0471

IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 et seq.) DOCKET NO. E-01345A-97-0772
1933

IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.) DOCKET NO. RE-00000C-94-0165

NOTICE OF FILING

Staff of the Arizona Corporation Commission ("Staff") hereby files the attached Settlement Agreement between Staff and Tucson Electric Power Company ("TEP"). The Settlement Agreement resolves outstanding issues in the above-referenced matters. Staff intends to file a proposed form of order, acceptable to both Staff and TEP, which would adopt the Settlement Agreement.

RESPECTFULLY SUBMITTED this 5th day of November, 1998

Paul A. Bullis

Paul A. Bullis
Christopher C. Kempley
Janice Alward
Janet Wagner
Attorneys, Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Original and ten copies of the foregoing filed this 5th day of November, 1998 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Copy of the foregoing was mailed this 5th day of November, 1998 to:

All parties in Docket Nos. E-01933A-98-0471, E-01933A-97-0772 and RE-00000C-94-0165

By: Mary Ippolito

TUCSON ELECTRIC POWER COMPANY, INC.
DOCKET NO. E-01933A-98-0471
DOCKET NO. E-01933A-97-772
DOCKET NO. RE-00000C-94-0165

SETTLEMENT AGREEMENT

The undersigned parties stipulate and agree to the following settlement provisions in connection with the following applications submitted to the Arizona Corporation Commission ("Commission") by Tucson Electric Power Company, Inc. ("TEP" or "Company"): (Docket E-01933A-98-0471 and Docket No. E-01933A-97-772.

In addition, this Settlement Agreement ("Agreement") settles all issues arising from or related to the Commission's Electric Competition Rules as set forth in Decision Nos. 59943, 60977 and 61071.

Statement of Intention.

The purpose of this Agreement is to resolve contested matters in a manner consistent with the public interest. The contested matters were generated, in large measure, as a result of the Commission's Retail Electric Competition Rules and TEP's regulatory filings made in response thereto. The parties recognize that the electric utility industry is undergoing a transition to competition, which is scheduled to begin in fewer than one hundred days.

It is the intention of the parties, through this Agreement, to provide resolution of the contested matters regarding TEP's unbundled tariffs, TEP's requested stranded cost recovery, and certain outstanding matters related to the Commission's Retail Electric Competition Rules. This settlement is intended to be comprehensive and will serve to make an efficient and cost effective transition to a new era of customer choice in a new competitive market structure. Therefore, the parties believe that this settlement is in the public interest.

The parties also agree that, under this Agreement, the basis for the opportunity for the recovery of TEP's stranded cost is the divestiture of TEP's generation assets. For purposes of this Agreement, the term "divestiture" under the Commission's rules includes TEP's divestiture of generation assets as agreed to herein. TEP's divestiture of these generation assets addresses concerns regarding TEP's vertical market power and as such constitutes a change in market structure in the transition to competition.

I. Contingency of Agreement.

This Agreement is contingent upon Commission approval of the Agreement including a proposed order to be mutually acceptable to Staff and TEP, which proposed order shall, inter alia, address issues necessary in order to complete securitization.

II. Unbundled Rates.

The Company's unbundled rates and charges as filed on December 31, 1997, in Docket No. E-01933A-97-0772, as modified to reflect the 1.1 percent reduction approved by the Commission in Decision No. 61104 shall also be modified to reflect the metering, billing, and other distribution costs from a recent cost of service study approved by the Commission (attached as Exhibit A). Unbundled tariffs shall identify separately distribution, transmission (determined from the current FERC transmission rates), metering, billing service, System Benefits, Market Generation Charge, Regulatory Asset Charge, and an Interim Transition Charge ("ITC") or Competition Transition Charge ("CTC"), where applicable.

A quarterly Firm Wholesale Market Generation Charge (MGC) shall be calculated for a 12 month period based on shaping the Palo Verde NYMEX futures price by the California hourly spot market index plus 3.5 mills. This adder reflects ancillary services, capacity, reserves, and other necessary generation costs. The individual retail MGC's shall be calculated for each rate class by adjusting for class line losses and inclusion of the appropriate load factor. This 3.5 mill "adder" shall remain in effect unchanged until December 31, 1999, after which the MGC may be revised to reflect then current market generation costs. The adders applied to each class shall be 4.0 mills for the residential and commercial classes and 2.6 mills for the industrial class. The quarterly ITC will be the residual after subtracting distribution, transmission, metering, billing and the retail MGCs.

III. Recovery of Regulatory Assets.

TEP will be allowed 100 percent recovery of regulatory assets in accordance with the terms of this agreement. The rates for regulatory assets will be identified separately in the unbundled tariffs.

IV. Recovery Of Stranded Cost and CTC.

A. **Assets to be *Auctioned***. It is the Commission's intent that TEP receive full recovery of stranded costs associated with its generation assets, that will be subject to a competitive auction. The company's DeMoss Petrie and North Loop generation sites will be retained by the Company until such time as it is determined they are needed for siting additional generation for reliability purposes. At such time, they will be auctioned subject to the execution by the purchaser of a definitive must-run (local reliability support) agreement on terms which have been approved by the Commission, and any proceeds above book value shall be reflected in a reduction to rates.

B. **Interim Transition Charge to recover stranded generation costs and regulatory assets.** Prior to divestiture, TEP will be allowed to collect an Interim Transition Charge, as set forth in Exhibit B, that shall be determined for each class as the residual between the existing rate level and the separate charges for metering, billing, systems benefits, transmission, distribution, and the retail Market Generation Charge including the adder. If the actual spot market price for a quarter differs from the projected price by more than 5%, and the amount of load choosing competitive suppliers is of sufficient quantity that the Company undercollects or overcollects generation costs by more than 10% in a quarter or 2% in a year, it should file a plan with the Commission to increase or decrease the ITC (for the next quarter or year) or to reflect this difference in the permanent CTC. During this interim period, generating assets will continue to be depreciated at the current rate.

C. **Estimate of stranded costs associated with particular units if auction of those units fails.** If a particular asset is not divested because the auction does not produce bids that are acceptable in accordance with the provisions herein, the stranded cost associated with the unit shall be estimated and shall be recovered as described in D and E below.

D. **Methodology for estimating stranded costs.** In case of failed auction, the methodology for estimating stranded costs shall be the net revenues lost methodology, calculated over the life of the asset. This methodology is understood to be the estimation of the difference between the market revenues produced by generation assets and the unmitigated embedded costs of continuing to operate the units (as long as cost effective) based on cost of service ratemaking.

E. **Permanent CTC.** After the divestiture process, the sum of positive stranded costs shall be determined either by the auction proceeds, the estimate of stranded costs, or a combination of the two methodologies in accordance with Exhibit C attached to this Agreement. The total positive stranded costs shall be recovered, with a carrying charge equal to the Company's imputed cost of capital, over six to eight years as needed subject to the Commission's discretion regarding the recovery period consistent with the terms of the securitization bonds. If there are assets which produce negative stranded costs, other than those which have been allowed to be used to acquire transmission assets, the CTC shall also be reduced by reflecting a return of these negative stranded costs to ratepayers over the period during which positive stranded costs are being collected.

F. **Failure to divest.** In the event that TEP does not divest as defined herein, TEP shall be permitted an opportunity to recover transition revenues to maintain its financial viability. These will be sufficient revenues to cover debt payments. If there is no divestiture as the result of a failed auction as defined in Section VI , the provisions of IV.D shall apply.

VI. Securitization and Accounting and Ratemaking Authority for Stranded Costs.

If securitization will reduce the total cost to customers for regulatory assets and/or stranded cost recovery, the Company shall securitize all regulatory assets and/or stranded costs resulting from the divestiture. An allowance for an equity return on the unamortized amounts will be imputed using TEP's return on equity as authorized in Commission Decision No. 59594 applied to a hypothetical capital structure consisting of 35% equity and 65% debt. If securitization is not possible, the Commission will approve the necessary accounting assurances to comply with FAS 71, i.e. allowance of a return on the unamortized balance and a recovery period of less than 10 years.

To the extent the final sale price of any Assets (including the value assigned such Asset in an exchange along with the economic value of the Company's power sale agreement with SRP) is greater than the Company's net book values for such assets, any gain received, up to 35% of the net book value of any transmission assets purchased from APS, SRP, AEPCO or others as approved by the Commission, will be utilized to capitalize the acquisition of transmission assets ("Capitalized Balance"). For purposes of this agreement, any executed letter of intent to purchase transmission assets from APS, SRP, AEPCO or others which is executed prior to December 31, 2000, shall be included. Any gain remaining shall be treated as described in Section IV. It is the parties' intention to provide TEP with an opportunity to utilize the Capitalized Balance in the Transco without increasing the stranded cost to TEP's customers. In exchange TEP's jurisdictional rates will be reduced by an amount equal to the return on the Capitalized Balance, calculated using the CTC after-tax weighted average cost of capital for the term of any CTC recovery. Thereafter, TEP's rates will be reduced to reflect the recovery of the common equity balance over a ten year period on a straight-line basis

VII. Divestiture.

A. The auction process set forth in TEP's Application and the auction protocols set forth in the Confidentiality and Auction Protocols Agreement attached to this Settlement Agreement shall be approved, subject to the following:

1. The Commission shall review the bids received with respect to each Asset; and in the event the Commission determines such bids are not representative of the market value of such Asset based on the nature of bids received and/or relevant market data, it may declare a failed auction with respect to such Asset.

2. In the event the Commission declares a failed auction with respect to any Asset, the Company shall have the option of: i) proceeding with the sale of the Asset at the highest bid price, in which case the Commission shall determine the Company's stranded cost resulting from the Asset as the lower of: a) the Company's stranded cost resulting from all costs associated with the Asset remaining with the Company after application of the proceeds from the highest bid price, or b) the stranded costs resulting from the Company's costs of retaining the Asset and the market proceeds from continuing to operate the Asset, as determined by the Commission; or ii) retaining the Asset and recovering the stranded costs relating to such Asset based on the "Net Revenues Lost" methodology.

3. The obligation of the Company to complete the divestiture of any Asset shall be conditioned upon the receipt by the Company of any necessary regulatory approvals, including to the extent required, FERC, FTC (Hart-Scott-Rodino_ or SEC approvals. In the event TEP is unable to obtain any necessary regulatory approval for the transfer of an Asset, the Commission shall declare a failed auction with respect to such Asset, and TEP shall recover the stranded costs relating to such Asset based on the "Net Revenues Lost" methodology.

4. The divestiture of all local generation assets (Irvington and the combustion turbines) shall be subject to the execution by the purchaser of must-run agreements providing local support, in the form approved by the Commission. TEP shall present to the Commission a detailed protocol for addressing the pricing provisions associated with the so-called "must-run" units, which will be included in the divestiture documents.

VIII. Transco.

The Company may acquire the non-distribution related transmission assets (the "Transmission") of Arizona Public Service Company ("APS"), at APS' book value for such assets, upon the terms set forth in the attached Memorandum of Understanding.

Two objectives should be met to eliminate vertical market power and achieve competition:

(1) all network customers in an access area (or zone) should pay the same rate for transmission service.

(2) all customers should have equal access to any generation within the region at no additional cost. Allocation priorities and transmission constraints and/or the definition and allocation of Available Transmission Capacity (ATC) established by the ISA/ISO should not unduly frustrate competition.

These objectives can be met using either a region-wide "postage stamp" approach or a properly implemented "license plate" approach. If a "license plate" approach is to be used, it must be "all inclusive", i.e., all intra-regional transmission costs currently being paid by network customers within each access area must be absorbed by the access area provider and reflected in the "license plate" rate. Under any pricing approach, congestion management and ATC determination will be crucial to a successful implementation. The following principles will apply:

- ♦ The Transco will acquire all transmission facilities owned by TEP, APS, SRP, AEPCO and others, as approved by the Commission, at voltage levels defined by individual agreement. This is required for all components of the transmission system that may be subject to Committed Uses or constraints which, in turn, may be used to promote Vertical Market Power.
- ♦ At the time of transfer of the TEP transmission assets to Transco, an associated transfer of debt and equity will also be made. TEP will transfer debt and equity in the same proportion as their actual capital structure. TEP shall provide the Staff with a summary of the journal entries recorded at the time of the asset transfer.
- ♦ The Transco will file comparable network and point-to-point tariffs, providing transmission service on an individual "license plate" basis for APS' and TEP's respective service areas, and including adjacent systems as appropriate when the ISA and/or ISO is implemented. No wholesale or retail customer in APS' or TEP's access area will be required to pay both APS and TEP for transmission service.
- ♦ TEP will work with APS to pursue the "license plate" approach and requisite filings even if the current ISA implementation plan fails to materialize or receive FERC approval as currently proposed.
- ♦ TEP will work with APS to ensure that all Committed Uses under their control will be used for Load within their respective access areas on a non-discriminatory basis:
  - ➢ The definition of All Committed Uses (existing or contemplated) supported by TEP will be explained to the ACC's satisfaction.

- If FERC rejects or otherwise orders TEP to modify its commitments, TEP will comply accordingly and will not seek to relieve itself of the obligations accepted herein.
- TEP will not transfer any Committed Uses with its generation divestiture.
- TEP will work with APS to ensure that any and all Committed Uses are applied in a consistent manner for all transmission facilities so that no generation resources are given a competitive advantage by virtue of contractual constraints or protocols (as contemplated in the ISA filing) designed to limit ATC.

- TEP will work with APS to pursue in good faith any mitigation measures (Re: The "license plate" approach) that are necessary for a full region-wide Desert Star (or other ISO) implementation without "pancaked" rates.
- In order to prevent the occurrence of vertical market power, it is the intent of the Staff and, by its approval of this Agreement, the Commission, that TEP's transmission company affiliate be the sole builder and owner of transmission assets in the state.

IX. Rate Reductions.

TEP's rate reductions shall be as specified in the Settlement Agreement executed by Staff and the Company, dated August 19, 1998 and incorporated in Commission Decision No. 61104.

X. Waivers

Although TEP may no longer be vertically integrated, it will remain a regulated monopoly distribution company. TEP's capital structure reflects only 15 percent common equity and 85 percent debt and its non-utility affiliates are suffering net losses. Therefore, Staff believes that until TEP's financial health is improved to a level where its equity position is reasonably strong (37.5 percent equity), that a complete waiver of the Affiliated Interest Rules and the waiver of the conditions included in the Holding Company Decision would not be in the public interest.

However, Staff agrees that a partial waiver of the Affiliated Interest Rules, a partial waiver from the conditions in Decision No. 60480, and waivers from selected Commission decisions would be consistent with the onset of competition and the divestiture of generation assets while maintaining a moderate level of oversight.

TEP has requested waiver of Commission rules and orders. The Staff is recommending the following responses to these various requests for waivers to the Commission:

- **R14-2-701, et seq. – Integrated Resource Planning Rules.**

- TEP should comply with the Resource Planning Rules until divestiture of its generation. After such time as divestiture occurs, Staff believes that the IRP Rules do not apply to TEP pursuant to R14-2-702.A. Pursuant to R14-2-702.B, the Commission may apply the IRP Rules to TEP upon two years notice. Staff does not believe that it is in the public interest for the Commission to agree to forego its authority pursuant to R14-2-702.B at this time.

- **R14-2-801, et seq. – Affiliated Interest Rules.**

  R14-2-803 should be limited to organizations or reorganizations of UniSource when the organization or reorganization changes the position of TEP (UDC) in the holding company organizational structure.
  R14-2-804 (A) Agreement by affiliates to allow Commission access to its books and records may be limited to investigations which are performed during the course of a rate case.

  R14-2-805 (A) should be limited to require annual filings by only TEP (UDC), unless the diversification plans or efforts of affiliates are likely to adversely affect the UDC's financial integrity.

  R14-2-805 (A)(2) should be limited to a broad description of the nature of the business of each affiliate.

  R14-2-805 (A)(6) should be limited to disclosure of allocations applicable to the UDC. However, the Commission's jurisdiction to require disclosure of the bases of other allocations should be reserved for rate cases.

  R14-2-805 (A)(9)(10) and (11) should be limited to production of such documents in rate cases and no annual filing is necessary.

- **Decision No. 60480, Holding Company Order.**

  Condition Nos 2, 13, and 17 are waived under this Agreement.

  Condition No. 12. The Staff recommends that the Commission waive the filing requirements for sister companies. However, TEP should continue to file quarterly. TEP's holding company should file annually. SEC filings should be filed with the Commission as required under Condition 12.

  Condition 19 should be modified to reduce the percentage of UniSource equity issuances that must be shared with TEP from 60 percent to 30 percent.

Conditions 19, 20 and 21 should remain in force, as modified, until the equity portion of TEP's capital structure reaches or exceeds 37.5 percent. The Staff is not opposed, however, to reconsideration of a request for waiver of these conditions in conjunction with TEP's next rate case.

Condition No. 26 should remain in effect but should be limited to TEP employees.

Condition No. 27. The Staff recommends that the Commission waive the requirement for annual filings. However, this waiver does not preclude the Commission from requiring the filing of information that would have been filed annually for purposes the Commission deems necessary, including but not limited to rate setting.

- **Decision No. 59594 – Cost Containment Report**

Staff recommends that the Commission waive the requirement to file the Cost Containment Report.

- **Decision No. 59594 – Mid-Year DSM and Renewables Report**

TEP should comply with this filing requirement until such time as divestiture occurs. Thereafter, Staff recommends that the requirement to file mid-year DSM and Renewables Reports be waived.

- **Decision No. 57586 – Director Transaction Report**

Staff recommends that the requirement to file the Director Transaction Report be waived by the Commission.

- **Decision No. 58316 – Investment Subsidiary Liquidation Report and Purchase Agreement Summary**

Staff recommends that the requirement to file an Investment Subsidiary Liquidation Report and Purchase Agreement Summary be waived by the Commission.

- **Decision No. 58497 – Avoided Cost Report**

  Staff recommends that the requirement to file an Avoided Cost Report be waived after divestiture of generating assets by the Commission.

- **Decision No. 57090 – Time of Use Letters**

  Staff recommends that the Commission waive the filing of the Time of Use Letters Report after divestiture of the generating assets.

- **Decision No. 56659 – Time of Use Report**

  Staff recommends that the Commission waive the filing of the Time of Use Report after divestiture of the generating assets.

- **Decision No. 56526 – Fuel & Performance Filing**

  Staff recommends that the requirement to make a Fuel and Performance filing be waived by the Commission after divestiture of the generating assets.

- **Decision No. 57924 – Interruptible Report**

  Staff recommends that the requirement to file an Interruptible Report be waived by the Commission after divestiture of the generating assets.

- **Statistical Data on Generating Units**

  Staff recommends that the requirement to file Statistical Data on Generating Units Reports be waived by the Commission after divestiture of the generating assets.

- **Generating Unit Outage Report**

  Staff recommends that the requirement to file Generating Unit Outage Reports be waived by the Commission after divestiture of the generating assets.

XI. Independent Scheduling Administrator/Independent System Operator.

The Company shall commit to having an independent scheduling administrator (ISA) in place by December 31, 1998 and commit to facilitating the development of an independent system operator (ISO) for Arizona by December 31, 2000. In the event TEP does not have an independent scheduling administrator in place by December 31, 1998 or, an independent system operator by December 31, 2002, the Commission shall examine the reason(s) for the failure and the efforts expended by TEP in compliance with this Section. As used in this Section, an independent system operator is an independent entity, responsible for, among other things, supervising access to the interconnected transmission system. The ISA/ISO also calculates available transmission capacity and implements protocols for system transfer capabilities, committed uses of the transmission system, must-run generating units (as determined by the Commission) and provides dispute resolution such that market participants can expeditiously resolve dispute claims. If an Arizona only ISO is established, it is anticipated that it would join a regional ISO when one is established.

XII. Section 40-252 – Certificate of Convenience and Necessity

TEP agrees to modify its Certificate(s) of Convenience and Necessity to permit competition pursuant to A.A.C. R14-2-1600, et seq., as amended. The Order adopting this Settlement Agreement shall constitute the necessary Commission Order modifying TEP's CC&Ns to permit competition.

XIII. Resolution of Litigation.

Upon issuance by the Commission of a final non-appealable order approving this Agreement, TEP shall move to dismiss with prejudice all pending litigation brought by TEP against the Commission. In the event it has not already done so, TEP further agrees that it will not appeal Decision No. 60977, Decision No. 61071 (the Commission's order adopting amendments to A.A.C. R14-2-1600, et seq., And R-14-2-200, et. Seq., on a permanent basis). As mutually agreed, TEP will actively support the Commission's position and assist the Commission in any remaining litigation regarding the Commission's Electric Competition Rules, or related matters.

XIV. Tariff Filings.

The Parties agree and stipulate that the Company is obligated to prepare its ACC unbundled tariffs under the requirement of this Agreement. The Company will file said tariffs by November 15, 1998. The Parties agree and understand that these tariffs will not be effective or implemented until approved by Commission Order. The proposed tariffs will be served on all parties in this proceeding who will have an opportunity to comment prior to implementation. TEP agrees to seek all regulatory approvals necessary to implement this Settlement and the Electric Competition Rules.

XV. Solar Portfolio Requirements.

TEP agrees to meet the requirements of the Solar Portfolio Standard, Section 1609 of the rules, as amended in August 1998. TEP agrees to support the continuation of the Solar Portfolio Standard in future Commission proceedings. TEP agrees to continue the programs included in the System Benefits Charge at a level equal to or greater than the level at which TEP was funding those programs in 1997. If TEP should incur uncollectible Solar Power costs, TEP will be allowed to defer such costs for later full recovery, beginning January 1, 2003.

As applied to TEP (as a utility distribution company), the solar portfolio standard ("SPS") will be met by TEP purchasing all the necessary solar power through an RFP process and recovering the associated costs through a "green" solar rate to market such solar power to its Standard Offer customers at a price designed to recover such costs (but, in the event revenue from such rate plus any additional revenue received from the sale of solar power to any other entities is not sufficient to fully recover such costs, any deficiency shall be deferred for recovery [including a reasonable return] under the mechanism described above). The RFP process and cost recovery mechanism will be subject to (1) approval of the RFP by the Director of the Utilities Division by July 1, 1999, and (2) joint approval, by TEP and the Director of the Utilities Division, of a successful, qualified responsive bid to such RFP.

MISCELLANEOUS PROVISIONS

1. Admissions.

This Agreement represents an attempt to compromise and settle disputed claims arising out of TEP's Applications in a manner consistent with the public interest. Nothing contained in this Agreement is an admission by any of the parties that any of the positions taken, or that might be taken by each in formal proceedings, is unreasonable. In addition, acceptance of this Agreement by the parties is without prejudice to any position taken by any party in these proceedings.

2. Commission Action.

Each provision of this Agreement is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission without change. In the event that the Commission fails to adopt this Agreement according to its terms by November 25, 1998, this Agreement shall be deemed withdrawn and the parties shall be free to pursue their respective positions in these proceedings without prejudice.

3. Limitations.

The terms and provisions of this Agreement apply solely to and are binding only in the context of the provisions and results of this Agreement and none of the positions taken herein by the parties may be referred to, cited or relied upon by any other party in any fashion as precedent or otherwise in any other proceeding before this commission or any other regulatory agency or before any court of law for any purpose except in furtherance of the purposes and results of this Agreement.

4. To the extent that any provision of this Agreement is inconsistent with the Commission's Electric Competition Rules, this Agreement is intended to apply.

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5. Proposed Order.

The parties shall agree to a proposed form of order approving this Agreement, which form of order shall be filed with the Commission.

Dated this Nov 4, 1998

Tucson Electric Power Company

By: [signature]

Title: PRESIDENT, CEO

Arizona Corporation Commission

By: Jack Rose

Title: Executive Secretary

Decision No. ___________

Exhibit A

Composed of:

Schedule G-1a	Unbundling
Schedule G-1b	Distribution Service Cost of Service
Schedule G-1c	Distribution Unit Cost by Function by Class
Schedule G-1c	Unit Cost Calculation

Tucson Electric Power Company
Schedule G-1--Unbundling

Transmission and Distribution Unit Costs

	Total	Residential	General Service	Large Light & Power	Contracts	Lighting	Public Authority
1 Peaks & Average Allocation	100.00%	36.37%	35.47%	7.48%	17.65%	0.30%	2.74%
2 Transmission $	$ 51,125,067	$ 18,591,849	$ 18,131,852	$ 3,822,519	$ 9,022,318	$ 153,365	$ 1,403,164
3 Units	7,462,855	2,545,214	2,456,342	663,246	1,565,463	35,798	196,792
4 Unit Cost Transmission	$ 0.0069	$ 0.0073	$ 0.0074	$ 0.0058	$ 0.0058	$ 0.0043	$ 0.0071
5 Unit Cost Distribution (Schedule G1c) (Note: D breakdowns by fuction in G1c)	$ 0.0136	$ 0.0311	$ 0.0210	$ 0.0014	$ 0.0013	$ 0.0469	$ 0.0156
6 Total T&D Component	$ 0.0255	$ 0.0384	$ 0.0284	$ 0.0072	$ 0.0071	$ 0.0512	$ 0.0227

Summary of Generation, Transmission, and Distribution Unit Costs

	Residential	General Service	Large Light & Power	Contracts	Lighting	Public Authority
7 Average Total Price	$ 0.0931	$ 0.1042	$ 0.0686	$ 0.0686	$ 0.0860	$ 0.0782
8 Total T&D Component	$ 0.0384	$ 0.0284	$ 0.0072	$ 0.0071	$ 0.0512	$ 0.0227
9 Total Generation Component	$ 0.0547	$ 0.0759	$ 0.0614	$ 0.0615	$ 0.0348	$ 0.0555

Note: LL&P and Contracts Based on Tariff

10 Total Generation Component by Rate Schedule (See Line 9 for Weighted Averages Over the Broad Classes)

	Residential	General Service	Large Light & Power	Contracts	Lighting	Public Authority
Schedule 1, 70	$ 0.0547					
Schedule 10, 76		$ 0.0879				
Schedule 11		$ 0.0688				
Schedule 31		$ 0.0418				
Schedule 13, 85		$ 0.0655				
Schedule 14, 90			$ 0.0614	$ 0.0614		
Schedule 41, 50, 51					$ 0.0348	
Schedule 40, 43 F						$ 0.0664
Schedule 40, 43 I						$ 0.0332

Tucson Electric Power Company
Distribution Service Cost of Service
Schedule G-1
(Thousands of Dollars)

Line No.	Description	Total	Residential	General Service	Large Light & Power	Lighting	Contracts	Public Authority	Direct Assignment to GS and LL&P
1	Revenues								
2	Net Sales to Ultimate Customers	139,111	79,203	51,472	939	1,679	2,093	3,073	652
3	SCE Exchange	0	0	0	0	0	0	0	0
4	Other Electric Revenue	0	0	0	0	0	0	0	0
5	Total Revenues	139,111	79,203	51,472	939	1,679	2,093	3,073	652
6	Operating Expenses Excluding Income Taxes	98,375	56,967	34,507	914	1,051	2,068	2,073	795
7	Operating Income Before Income Taxes	40,736	22,237	16,964	25	628	25	1,001	(143)
8	Income Taxes	10,554	5,761	4,395	6	163	6	259	(37)
9	Operating Income	30,182	16,475	12,569	18	465	18	741	(106)
10	Rate Base	354,576	193,553	147,663	217	5,466	217	8,709	(1,247)
11	Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
12	Index of Return	100.000	100.000	100.000	100.000	100.000	100.000	100.000	100.000

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Residential

Line No.	Total	Distribution Primary	Distribution Secondary	Total Demand	DSM E-2	Uncollectible E2	Customer Info E2	Total Energy	Customer Service Drop	Customer Accounting	Customer Meter Reading	Customer Metering	Specific Assignment - Residential
Rate Base	193,553	112,669	49,970	162,639	0	0	0	0	25,312	0	0	11,313	(5,711)
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	16,475	9,590	4,253	13,844	0	0	0	0	2,155	0	0	963	(486)
Expenses	56,967	22,732	10,081	32,813	1,456	313	1,614	3,383	6,214	8,960	2,413	2,803	380
Total of Return & Expenses	73,442	32,322	14,335	46,657	1,456	313	1,614	3,383	8,368	8,960	2,413	3,766	(107)
Income Taxes	5,761	2,536	1,125	3,660	114	25	127	265	656	703	189	295	(8)
Total Revenue Requirement	79,203	34,858	15,460	50,317	1,570	338	1,741	3,649	9,025	9,663	2,603	4,062	(115)
SCE Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	79,203	34,858	15,460	50,317	1,570	338	1,741	3,649	9,025	9,663	2,603	4,062	(115)
Percent of Total (Row 17)	100.00%	44.01%	19.52%	63.53%	1.98%	0.43%	2.20%	4.61%	11.39%	12.20%	3.29%	5.13%	-0.15%
Total Units (Energy)	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214
Unit Cost ($/kWh)	$0.0311	$0.0137	$0.0061	$0.0198	$0.0006	$0.0001	$0.0007	$0.0014	$0.0035	$0.0038	$0.0010	$0.0016	($0.0000)

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Residential

Line No.	Specific Assignment - General Service	Specific Assignment - Large Light & Power	Specific Assignment - Lighting	Specific Assignment - Public Authority	Specific Assignment - Other	Total Customer
Rate Base	0	0	0	0	0	30,914
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	0	0	0	0	0	2,631
Expenses	0	0	0	0	0	20,770
Total of Return & Expenses	0	0	0	0	0	23,402
Income Taxes	0	0	0	0	0	1,836
Total Revenue Requirement	0	0	0	0	0	25,237
SCE Exchange	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	0	0	0	0	0	25,237
Percent of Total (Row 17)	0.00%	0.00%	0.00%	0.00%	0.00%	31.86%
Total Units (Energy)	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214	2,545,214
Unit Cost ($/kWh)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0099

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

General Service

Line No.	Total	Distribution Primary	Distribution Secondary	Total Demand	DSM E-2	Uncollectible E2	Customer Info E2	Total Energy	Customer Service Drop	Customer Accounting	Customer Meter Reading	Customer Metering	Specific Assignment - Residential
Rate Base	147,663	100,291	41,372	141,663	0	0	0	0	2,637	0	0	3,362	0
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	12,569	8,537	3,522	12,059	0	0	0	0	224	0	0	286	0
Expenses	34,507	20,234	8,347	28,581	1,403	302	1,556	3,261	647	934	251	833	0
Total of Return & Expenses	47,077	28,771	11,869	40,640	1,403	302	1,556	3,261	872	934	251	1,119	0
Income Taxes	4,395	2,686	1,108	3,794	131	28	145	304	81	87	23	104	0
Total Revenue Requirement	51,472	31,457	12,977	44,434	1,534	330	1,701	3,565	953	1,021	275	1,224	0
SCE Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	51,472	31,457	12,977	44,434	1,534	330	1,701	3,565	953	1,021	275	1,224	0
Percent of Total (Row 17)	100.00%	61.12%	25.21%	86.33%	2.98%	0.64%	3.30%	6.93%	1.85%	1.98%	0.53%	2.38%	0.00%
Total Units (Energy)	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342
Unit Cost ($/kWh)	$0.0210	$0.0128	$0.0053	$0.0181	$0.0006	$0.0001	$0.0007	$0.0015	$0.0004	$0.0004	$0.0001	$0.0005	$0.0000

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

General Service

Line No.	Specific Assignment - General Service	Specific Assignment - Large Light & Power	Specific Assignment - Lighting	Specific Assignment - Public Authority	Specific Assignment - Other	Total Customer
Rate Base	0	0	0	0	0	1,613
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	0	0	0	0	0	137
Expenses	0	0	0	0	0	2,894
Total of Return & Expenses	0	0	0	0	0	3,031
Income Taxes	0	0	0	0	0	283
Total Revenue Requirement	0	0	0	0	0	3,314
SCE Exchange	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	0	0	0	0	0	3,314
Percent of Total (Row 17)	0.00%	0.00%	0.00%	0.00%	0.00%	6.44%
Total Units (Energy)	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342	2,456,342
Unit Cost ($/kWh)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0013

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Large Light & Power

Line No.	Total	Distribution Primary	Distribution Secondary	Total Demand	DSM E-2	Uncollectible E2	Customer Info E2	Total Energy	Customer Service Drop	Customer Accounting	Customer Meter Reading	Customer Metering	Specific Assignment - Residential
Rate Base	217	0	0	0	0	0	0	0	0	0	0	217	0
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	18	0	0	0	0	0	0	0	0	0	0	18	0
Expenses	914	0	0	0	365	78	405	848	0	10	3	54	0
Total of Return & Expenses	933	0	0	0	365	78	405	848	0	10	3	72	0
Income Taxes	6	0	0	0	3	1	3	6	0	0	0	0	0
Total Revenue Requirement	939	0	0	0	367	79	407	854	0	10	3	73	0
SCE Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	939	0	0	0	367	79	407	854	0	10	3	73	0
Percent of Total (Row 17)	100.00%	0.00%	0.00%	0.00%	39.11%	8.41%	43.36%	90.8[illegible]%	0.00%	1.09%	0.29%	7.73%	0.00%
Total Units (Energy)	663,246	663,246	663,246	663,246	663,246	663,246	663,246	663,24[illegible]	663,246	663,246	663,246	663,246	663,246
Unit Cost ($/kWh)	$0.0014	$0.0000	$0.0000	$0.0000	$0.0006	$0.0001	$0.0006	$0.001[illegible]	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Large Light & Power

Line No.	Specific Assignment - General Service	Specific Assignment - Large Light & Power	Specific Assignment - Lighting	Specific Assignment - Public Authority	Specific Assignment - Other	Total Customer
Rate Base	0	0	0	0	0	3,355
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	0	0	0	0	0	286
Expenses	0	0	0	0	0	633
Total of Return & Expenses	0	0	0	0	0	919
Income Taxes	0	0	0	0	0	6
Total Revenue Requirement	0	0	0	0	0	925
SCE Exchange	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	0	0	0	0	0	925
Percent of Total (Row 17)	0.00%	0.00%	0.00%	0.00%	0.00%	98.50%
Total Units (Energy)	663,246	663,246	663,246	663,246	663,246	663,246
Unit Cost ($/kWh)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0014

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Lighting

Line No.	Total	Distribution Primary	Distribution Secondary	Total Demand	DSM E-2	Uncollectible E2	Customer Info E2	Total Energy	Customer Service Drop	Customer Accounting	Customer Meter Reading	Customer Metering	Specific Assignment - Residential
Rate Base	5,466	1,032	451	1,483	0	0	0	0	494	0	0	0	0
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	465	88	38	126	0	0	0	0	42	0	0	0	0
Expenses	1,051	208	91	299	20	4	23	48	121	44	12	0	0
Total of Return & Expenses	1,516	296	129	425	20	4	23	48	163	44	12	0	0
Income Taxes	163	32	14	46	2	0	2	5	18	5	1	0	0
Total Revenue Requirement	1,679	328	143	471	23	5	25	53	181	48	13	0	0
SCE Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	1,679	328	143	471	23	5	25	53	181	48	13	0	0
Percent of Total (Row 17)	100.00%	19.52%	8.54%	28.06%	1.35%	0.29%	1.50%	3.14%	10.78%	2.89%	0.78%	0.00%	0.00%
Total Units (Energy)	35,798	35,798	35,798	35,798	35,798	35,798	35,798	35,798	35,798	35,798	35,798	35,798	35,798
Unit Cost ($/kWh)	$0.0469	$0.0092	$0.0040	$0.0132	$0.0006	$0.0001	$0.0007	$0.0015	$0.0051	$0.0014	$0.0004	$0.0000	$0.0000

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Lighting

Line No.	Specific Assignment - General Service	Specific Assignment - Large Light & Power	Specific Assignment - Lighting	Specific Assignment - Public Authority	Specific Assignment - Other	Total Customer
Rate Base	0	0	3,489	0	0	3,983
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	0	0	297	0	0	339
Expenses	0	0	527	0	0	704
Total of Return & Expenses	0	0	824	0	0	1,043
Income Taxes	0	0	88	0	0	112
Total Revenue Requirement	0	0	913	0	0	1,155
SCE Exchange	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	0	0	913	0	0	1,155
Percent of Total (Row 17)	0.00%	0.00%	54.36%	0.00%	0.00%	68.80%
Total Units (Energy)	35,798	35,798	35,798	35,798	35,798	35,798
Unit Cost ($/kWh)	$0.0000	$0.0000	$0.0255	$0.0000	$0.0000	$0.0323

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Public Authority

Line No.	Total	Distribution Primary	Distribution Secondary	Total Demand	DSM E-2	Uncollectible E2	Customer Info E2	Total Energy	Customer Service Drop	Customer Accounting	Customer Meter Reading	Customer Metering	Specific Assignment - Residential
Rate Base	8,709	5,911	2,450	8,361	0	0	0	0	86	0	0	262	0
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	741	503	209	712	0	0	0	0	7	0	0	22	0
Expenses	2,073	1,193	494	1,687	112	24	125	261	21	30	8	65	0
Total of Return & Expenses	2,814	1,696	703	2,399	112	24	125	261	28	30	8	87	0
Income Taxes	259	156	65	221	10	2	11	24	3	3	1	8	0
Total Revenue Requirement	3,073	1,852	768	2,620	123	26	136	285	31	33	9	95	0
SCE Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	3,073	1,852	768	2,620	123	26	136	285	31	33	9	95	0
Percent of Total (Row 17)	100.00%	60.26%	24.98%	85.24%	4.00%	0.86%	4.43%	9.28%	1.01%	1.08%	0.29%	3.10%	0.00%
Total Units (Energy)	196,792	196,792	196,792	196,792	196,792	196,792	196,792	196,792	196,792	196,792	196,792	196,792	196,792
Unit Cost ($/kWh)	$0.0156	$0.0094	$0.0039	$0.0133	$0.0006	$0.0001	$0.0007	$0.0014	$0.0002	$0.0002	$0.0000	$0.0005	$0.0000

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Public Authority

Line No.	Specific Assignment - General Service	Specific Assignment - Large Light & Power	Specific Assignment - Lighting	Specific Assignment - Public Authority	Specific Assignment - Other	Total Customer
Rate Base	0	0	0	0	0	348
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	0	0	0	0	0	30
Expenses	0	0	0	0	0	124
Total of Return & Expenses	0	0	0	0	0	154
Income Taxes	0	0	0	0	0	14
Total Revenue Requirement	0	0	0	0	0	168
SCE Exchange	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	0	0	0	0	0	168
Percent of Total (Row 17)	0.00%	0.00%	0.00%	0.00%	0.00%	5.48%
Total Units (Energy)	196,792	196,792	196,792	196,792	196,792	196,792
Unit Cost ($/kWh)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0009

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Contracts

Line No.	Total	Distribution Primary	Distribution Secondary	Total Demand	DSM E-2	Uncollectible E2	Customer Info E2	Total Energy	Customer Service Drop	Customer Accounting	Customer Meter Reading	Customer Metering	Specific Assignment - Residential
Rate Base	217	0	0	0	0	0	0	0	0	0	0	217	0
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	18	0	0	0	0	0	0	0	0	0	0	18	0
Expenses	2,068	0	0	0	861	185	955	2,001	0	10	3	54	0
Total of Return & Expenses	2,086	0	0	0	861	185	955	2,001	0	10	3	72	0
Income Taxes	6	0	0	0	3	1	3	6	0	0	0	0	0
Total Revenue Requirement	2,093	0	0	0	864	186	958	2,007	0	10	3	72	0
SCE Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	2,093	0	0	0	864	186	958	2,007	0	10	3	72	0
Percent of Total (Row 17)	100.00%	0.00%	0.00%	0.00%	41.28%	8.87%	45.77%	95.92%	0.00%	0.49%	0.13%	3.45%	0.00%
Total Units (Energy)	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463
Unit Cost ($/kWh)	$0.0013	$0.0000	$0.0000	$0.0000	$0.0006	$0.0001	$0.0006	$0.0013	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Tucson Electric Power Company
Distribution Unit Cost by Function by Class

Contracts Line No.	Specific Assignment - General Service	Specific Assignment - Large Light & Power	Specific Assignment - Lighting	Specific Assignment - Public Authority	Specific Assignment - Other	Total Customer
Rate Base	0	0	0	0	0	217
Rate of Return	8.512%	8.512%	8.512%	8.512%	8.512%	8.512%
Return on Rate Base	0	0	0	0	0	18
Expenses	0	0	0	0	0	67
Total of Return & Expenses	0	0	0	0	0	85
Income Taxes	0	0	0	0	0	0
Total Revenue Requirement	0	0	0	0	0	85
SCE Exchange	0	0	0	0	0	0
Other Electric Revenue	0	0	0	0	0	0
Total Other Revenue	0	0	0	0	0	0
Total Net Sales to Ultimate Customers	0	0	0	0	0	85
Percent of Total (Row 17)	0.00%	0.00%	0.00%	0.00%	0.00%	4.08%
Total Units (Energy)	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463	1,565,463
Unit Cost ($/kWh)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001

Tucson Electric Power Company
Unit Cost Calculation
(Average Over All Classes--for informational purposes only)

	Unit Cost	as %	Distribution
Total	$ 0.01864	100.000%	
Production Local	$ -	0.000%	
Production Other	$ -	0.000%	
Transmission EHV	$ -	0.000%	
Transmission Local	$ -	0.000%	
Distribution Primary	$ 0.00918	49.237%	$ 0.00918
Distribution Primary - Transformers	$ -	0.000%	$ -
Distribution Secondary	$ 0.00393	21.096%	$ 0.00393
Distribution Secondary - Transformers	$ -	0.000%	$ -
Total Demand	$ 0.01311	70.334%	
Fuel E-1 Local	$ -	0.000%	
Fuel E-1 Other	$ -	0.000%	
DSM E-2	$ 0.00060	3.221%	$ 0.00060
Uncollectible E2	$ 0.00013	0.692%	$ 0.00013
Customer Info E2	$ 0.00067	3.572%	$ 0.00067
Total Energy	$ 0.00140	7.485%	
Customer Service Drop	$ 0.00137	7.325%	$ 0.00137
Customer Accounting	$ 0.00145	7.754%	$ 0.00145
Customer Meter Reading	$ 0.00039	2.088%	$ 0.00039
Customer Metering	$ 0.00074	3.972%	$ 0.00074
Specific Assignment - Residential	$ (0.00002)	-0.083%	
Specific Assignment - General Service	$ -	0.000%	
Specific Assignment - Large Light & Power	$ 0.00009	0.468%	
Specific Assignment - Lighting	$ 0.00012	0.656%	
Specific Assignment - Public Authority	$ -	0.000%	
Specific Assignment - Other	$ -	0.000%	
Total Customer	$ 0.00423	22.670%	
			98.96%
Subtotal Excl. Specific Assignments			$ 0.01845
Subtotal Excl. Specific Assignments			
Subtotal Excl. Specific Assignments	$ 0.01845	98.958%	
Sum of Specific Assignments	$ 0.00019	1.042%	
Total	$ 0.01864	100.000%	

Interim Transition Charge Tariff

1. Purpose

The purpose of the Interim Transition Charge ("ITC") is to provide TEP with a reasonable opportunity to recover the Company's above-market generation costs during the period January 1, 1999 through the date the Competitive Transition Charge ("CTC") mechanism is implemented. Upon final divestiture, TEP will present to the Commission final stranded costs associated with divesting TEP's generation when the costs are known and measurable as required per ACC Decision No. 60977.

2. Applicability

TEP's ITC shall be recovered from all existing and future consumers in the service territory in which TEP provides transmission and distribution service, except as specifically delineated in Item 5 of this tariff.

3. Definitions

1) Cost of Capital

The monthly Cost of Capital is one-twelfth of TEP's authorized Cost of Capital approved by the Commission.

2) New York Mercantile Exchange ("NYMEX") futures price, Palo Verde delivery

TEP will use the NYMEX to forecast the market price for energy at Palo Verde. Electricity futures contracts are traded publicly at the New York Mercantile Exchange. Palo Verde Switchyard futures contracts are traded for monthly on-peak periods for 18 forward months. A futures contract is an agreement between a buyer and seller for delivery of a particular quantity of a commodity at a specific time, place and price. The price of the futures contract reflects the current market consensus of commodity price expectations in the future.

3) Dow Jones Palo Verde Index ("PVI")

Index TEP will use to determine the actual cost of generation in Arizona. The Dow Jones Palo Verde Index is a measure of actual spot market prices. Dow Jones collects volume and price data from the majority of entities who transact physical power at the Palo Verde Switchyard. The transaction data relates to daily and hourly trades only, it does not include monthly or longer transactions executed in the Over The Counter ("OTC") or NYMEX markets. The Palo Verde Index also excludes any transactions at Palo Verde scheduled to the California ISO.

4) California Power Exchange ("CAPX")

TEP will use the monthly average hourly, day-ahead unconstrained California PX price to shape the NYMEX futures price at Palo Verde delivery point (averaged monthly) to determine the projected cost of generation in Arizona.

5) Transition Period

Period between January 1, 1999 until the level of the CTC has been established and authorized for collection.

6) Departing Load

Any Standard Offer customer who chooses an Electric Service Provider other than TEP.

4. Interim Transition Cost Balancing Account (ITCBA)

1) General Principles

a) TEP shall maintain an ITCBA, and make entries on a monthly basis.

b) The monthly accumulated balance in the ITCBA (either under-or over-collections) shall accrue interest at a rate equal to TEP's overall Cost of Capital.

c) If the projected market price during the month is less than the actual PVI, a credit will be made to the ITCBA.

d) If the projected market during the month is greater than the actual PVI, a debit will be made to the ITCBA.

e) Any balance (over-or under-recovery) of the ITCBA at the date of divestiture will be recovered through a mechanism deemed appropriate by the Commission.

f) The UDC will have the responsibility of collecting the CTC either directly from customers or from ESPs.

2) Reporting Requirements

a) TEP shall provide quarterly reports to the Commission on the status of the ITCBA.

b) TEP shall provide to the Commission a forward-quarter PVI thirty days prior to the start of the quarter. In conjunction with this filing, TEP will provide the ITC component by rate schedule to be charged during the quarter for Standard Offer and Departing Load.

3) Accounts

a) ITC revenues will be recorded in TEP's revenue accounts along with the market price of generation.

b) The ITCBA shall record all adjustments to actual monthly PVI prices and ITC.

c) Per R14-2-1613N of the Electric Restructuring Rules, all customer bills after January 1, 1999 will list, at a minimum, the following billing cost elements:

1. Electricity Costs
   a) Generation
   b) Interim Transition Charge ("ITC")
   c) Fuel or purchased power adjuster, if applicable

2. Delivery Costs
   a) Distribution Services
   b) Transmission Services
   c) Ancillary Services

3. Other Costs
   a) Metering Services
   b) Meter Reading Services
   c) Billing and Collection Services
   d) System Benefits Charge

TEP will record the above categories within the appropriate Revenue Accounts on the Company's Books.

c) A contra account will be linked to the Revenue ITC Account to reflect any over- or under-recovery of the ITC amount in any month. The Contra ITC Account will reflect adjustments to the actual ITC amount collected from customers.

d) An ITCBA will be established to account for the over or under-recovery ITC liability of the Company or customers on a monthly basis.

5. Exceptions to ITC

Existing and future consumers in the service territory in which TEP provides transmission and distribution service will be excluded from the ITC Charge in the following instances:

Self-Generation, Demand-Side Management or Other Demand Reduction Attributable to any causes other than the Retail Access Provisions of Article R14-2-1607

Per R14-2-1607, any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand-side management or other demand reduction attributable to any cause other than the retail access provisions of Article R14-2-1607 shall not be used to calculate or recover any Stranded Cost from a consumer.

6. Calculation of the ITC

The ITC will be calculated as follows:

The market price of generation will be forecasted quarterly and compared to the actual spot market price to determine the proper level of ITC for each rate class during the Transition Period. If the difference between the forecasted and actual spot market price for a given quarter is more than five percent, and the amount of load choosing suppliers is of sufficient quantity that TEP under- or over-collects generation costs by more than 10 percent in a quarter, or two percent in a year, TEP will seek Commission approval to adjust the following quarter's or year's ITC accordingly. Based on the January 1999 projection of the spot market price, TEP will unbundle the generation component of the Standard Offer between the forecasted spot market quarterly price and the ITC. The ITC is the difference between the current embedded generation costs and the quarterly spot market price projection plus an overall adder of 3.5 mills for ancillary services, capacity, reserves and other necessary generation costs, that will remain in effect until December 31, 1999. By class this adder shall be 4.0 mills for the residential and commercial classes and 2.6 mills for the industrial class. We can define the ITC as:
{Standard Offer embedded cost of generation – [(Spot market price projection*Loss Factor) + Adder]} ; where the Loss Factor is (1+line loss percentage). Using a residential customer as an example, if the quarterly, loss-adjusted, spot market price is projected to be 2.2 cents (an adder of 4.0 mills is added to this price), and TEP's embedded cost of generation for its regular residential rate under the Standard Offer is 5.47 cents, the residential ITC rate is 2.87 cents. This residential ITC charge will be charged to all residential customers for the first quarter of 1999.

b) TEP will charge competitive customers the same ITC per rate schedule as the Standard Offer customer. The ITC rate for each rate schedule will remain in effect for the first quarter of 1999.

c) TEP will adjust the ITCBA to the actual PVI balance monthly. Any over-or under-recovery of the ITC will be recorded in the ITCBA Account.

d) Any over-or under-recovery of the ITC in the previous quarter will accrue interest based on the Company's approved cost of capital.

e) TEP will repeat the process for the second quarter of 1999.

7. Standard Offer Unbundling

The generation portion of each rate schedule will be utilized to determine the ITC amount during the transition period.

The generation portion of each rate schedule that will be used to determine the ITC is as follows:

Schedule	No.	Rate
Residential	(01, 70)	$0.0547 Per kWh
General Service	(10, 76)	$0.0879 Per kWh
Mobile Home Park	(11)	$0.0688 Per kWh
Interruptible Agricultural Pumping	(31)	$0.0418 Per kWh
Large General Service	(13, 85)	$0.0655 Per kWh
Large Lighting & Power	14, 90	$0.0614 Per kWh
Private Street and Area Lighting	(41, 50, 51)	$0.0348 Per kWh
Public Authorities Firm Interruptible	(40, 43)	 $0.0664 Per kWh $0.0332 Per kWh

Competition Transition Charge and Transition Component Tariff

Pursuant to Arizona Corporation Commission Decision No. _________ (the "Decision"), Tucson Electric Power Company (the "Company") hereby transmits for filing, on the pricing date of these Competition Transition Bonds (the "Bonds"), the initial Competition Transition Charges and the initial Transition Components for the Company's Standard Offer Tariff (collectively, the "CTC Charges") for all existing and future customers. Capitalized terms not otherwise defined herein shall have the meanings given them in the Decision.

PURPOSE

This filing establishes the CTC Charges and the True-Up Mechanism to assure that Transition Property is paid in full over the Transition Period. This filing also describes the Transition Property to be sold to the SPE, the debt service schedule for payment of principal and interest on the Bonds to be sold by the SPE, and certain other related matters.

BACKGROUND

In the Decision, the Commission authorized the Company to file this Tariff once the Final Stranded Cost Amount (the "FSCA") has been determined at the conclusion of divestiture pursuant to the auction procedure approved in the Decision and when pricing terms for particular Bonds have been established. In the Decision, the Commission also authorized the Company to sell the Transition Property to the SPE and authorized the SPE to issue Bonds in an aggregate principal amount not to exceed the FSCA. This Tariff establishes the CTC Charges in the manner authorized by the Decision. The Formula Schedule attached hereto contains the formulas for calculating various amounts set forth in this Tariff.

FINAL STRANDED COST AMOUNT AND THE TRANSITION PROPERTY

The FSCA is $___________, which the Commission has determined the Company is entitled to receive together with interest on the unpaid balance. Until the date on which the Bonds are issued, interest shall accrue on the FSCA at the Company's general authorized rate of return. From and after the date on which the Bonds are issued, interest shall accrue at the rate of ____% per annum. The interest rate has been calculated in accordance with the formula described in Section 1 of the Formula Schedule.

The Company's right to be paid these amounts through the collection of CTC Charges is the Transition Property which the Company is selling in whole or in part to the SPE. The Transition Property is to be collected in the future according to a schedule based upon level total principal and interest payments each year, adjusted within each year to reflect expected seasonal usage, and adjusted from year-to-year to reflect the expected annual growth in electricity consumption, all as set forth on Attachment 1.

ISSUANCE INFORMATION:

Competition Transition Bond Name: __________

Name of SPE:______

Trustee(s): __________

Closing Date: ________

Dated Date: __________

Amount Issued: __________

Issuance Costs: __________

Coupon Rate(s): __________

Call Features: __________

Principal Amortization Schedule: (See Attachment 2)

Distributions to Investors : [every month][every quarter][semiannually] commencing __________

Amount of Transition Property Sold: ___________

Expected Annual Growth in Electricity Consumption: __________

Quarterly Servicing Fee: __________

Threshold for Implementation of the Quarterly True-Up Adjustment Mechanism (if any): __________

Interest rate adder (See Formula Schedule, Section 1, fn 1): ___________

Gross-up factor (See Formula Schedule, Section 1): ________________

AUTOMATIC ADJUSTMENT MECHANISM

At least annually the servicer shall make a True-Up Mechanism filing (in the form attached hereto as Appendix A) to modify this Tariff in accordance with the Decision. If the specified threshold for implementation of the quarterly True-Up Adjustment Mechanism has been reached, the servicer will compare the actual outstanding balance of the Transition Property (computed on the basis of amounts actually received) with the expected outstanding balance as set forth in Attachment 1. If the variance is greater than the specified threshold, a change to the CTC Charges will be made via a quarterly True-Up Mechanism filing (in the form attached hereto as Appendix A) to modify this Tariff in accordance with the Decision.

At the time of any True-Up Mechanism filing, the allocation of revenue requirement among customer classes will be recalculated in accordance with the formula set forth under "CTC Charges" below. The amount of the adjustment (positive or negative) shall be recovered in the CTC Charges for usage of electricity during the shorter of (i) the twelve months following the effective date of the True-Up Mechanism filing, or (ii) the remaining period ending December 31, 2008.

CTC CHARGES

Table I below shows the current assumptions for each of the variables used in the CTC Charges calculation.

TABLE I **Input Values for CTC Charges**	
Expected monthly residential kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly general service kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly large light and power/special contracts kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly lighting kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly public authority – firm kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly public authority – interruptible kWh sales	
[Insert separate line for each of the next 12 months]	
Percent of revenue requirement allocated to residential customers	
Percent of revenue requirement allocated to general service customers	
Percent of revenue requirement allocated to large light and power/special contracts customers	
Percent of revenue requirement allocated to lighting customers	
Percent of revenue requirement allocated to public authority – firm customers	
Percent of revenue requirement allocated to public authority – interruptible customers	
Percent of residential customers' billed amounts expected to be uncollected	
Percent of general service customers' billed amounts expected to be uncollected	
Percent of large light and power/special contracts customers' billed amounts expected to be uncollected	
Percent of lighting customers' billed amounts expected to be uncollected	
Percent of public authority – firm customers' billed amounts expected to be uncollected	
Percent of public authority – interruptible customers' billed amounts expected to	

be uncollected	
[Insert the following six lines for each customer class (assumes that bills are written off after 6 months nonpayment)]	
Percent of billed amounts expected to be collected in current month	
Percent of billed amounts expected to be collected in second month after billing	
Percent of billed amounts expected to be collected in third month after billing	
Percent of billed amounts expected to be collected in fourth month after billing	
Percent of billed amounts expected to be collected in fifth month after billing	
Percent of billed amounts expected to be collected in sixth month after billing	
Expected Transition Property outstanding balance as of __/__/__**[First day of the next quarter]**	

Table II shows the initial CTC Charges calculated for each class of customer.

TABLE II	
Residential Customer CTC Charge	¢/kWh
General Service Customer CTC Charge	¢/kWh
Large Light and Power/Special Contracts Customer CTC Charge	¢/kWh
Lighting Customer CTC Charge	¢/kWh
Public Authority – Firm CTC Charge	¢/kWh
Public Authority – Interruptible CTC Charge	¢/kWh

The revenue requirement has been allocated among classes of customers on the basis of the formula described in Section 2 of the Formula Schedule. At the time of any True-Up Mechanism filing, the Company will recalculate the allocation of revenue requirement in accordance with the foregoing formula and will include the effect of that reallocation in the recalculation of the CTC Charges.

EXIT FEES

[Any customer may deliver written notice to the Company that the customer elects, effective on a date not less than 60 days after the date such notice is actually received by the Company, to pay a one-time fee in lieu of continuing to pay monthly CTC Charges. The Company will calculate such fee as the customer's pro rata share of the then outstanding principal of, and accrued interest on, the Transition Property, such pro rata share to be based on the customer's usage for the most recent twenty-four complete billing cycles, together with interest at the rate of __%

[the Transition Property interest rate] for 30 days. Payment of the fee will be due and payable 30 days after a bill therefor is mailed to the customer. Failure to pay this fee when due may result in termination of service and other remedies, consistent with standard Commission policies. In addition, late payment of the fee will accrue interest at the rate of __% **[the Transition Property interest rate]**.]

In the event that (a) any portion of the Company's distribution system is acquired by an entity other than a public service corporation regulated by the Commission, or (b) any portion of the Company's distribution system becomes subject to rate regulation other than by the Commission, unless either (i) provision is made for defeasance of the Transition Property and the CTBs with a portfolio of United States Treasury obligations or (ii) written consent is obtained from the SPE, the Company (or a successor servicer), and the CTB trustee, as soon as possible thereafter, for each of the Company's customers that will cease to receive electric distribution service from the Company at rates regulated by the Commission, the Company will calculate the obligation of each such customer to pay the Transition Property as each such customer's pro rata share of the then outstanding principal of, and accrued interest on, the Transition Property, such pro rata share to be based on each such customer's usage for the most recent twenty-four complete billing cycles, together with interest at the rate of __% **[the Transition Property interest rate]** for 30 days. The amount so calculated shall become due and payable by each of the Company's customers 30 days after a bill therefor is mailed to the customer. Failure to pay this fee when due may result in termination of service and other remedies, consistent with standard Commission policies. In addition, late payment of the amount owing will accrue interest at the rate of __% **[the Transition Property interest rate]**.

APPLICABILITY

The CTC Charges will be applied to all electricity usage through December 31, 2008, and recovered from all existing and future consumers in the service territory in which the Company presently provides transmission and distribution service, except to the extent that consumers either (i) pursuant to R14-2-1607, reduce electricity purchases from the Company as a result of self-generation, demand-side management or other demand reduction attributable to any cause other than the retail access provisions of Article 14-2 or (ii) pay exit fees as set forth above.

EFFECTIVE DATE

In accordance with the Decision, these CTC Charges shall be effective as of the effective date stated herein upon the filing of this tariff without further action of the Commission and will continue to be effective, unless they are changed by a subsequent CTC Charges tariff or by a CTC Charges True-Up Mechanism filing.

NOTICE

Copies of this filing are being furnished to ______________________________.

Enclosures

Attachment 1
Scheduled Collection for Transition Property[1]

Date	Principal	Interest	Total
[Monthly]			

[1] Determined in accordance with Section 1 of the Formula Schedule.

Attachment 2
Scheduled Principal Amortization and Interest Payments for Bonds[1]

Date	Principal	Interest	Total
[Quarterly]			

[1] Determined in accordance with Section 3 of the Formula Schedule.

Appendix A

Competition Transition Charge and Transition Component Tariff
True-Up Mechanism

Pursuant to Arizona Corporations Commission Decision No. ________ (the "Decision"), Tucson Electric Power Company (the "Company") as servicer of the Competition Transition Bonds (the "Bonds") and on behalf of the SPE is required to apply for adjustments to the CTC Charges at least 15 days before the end of each calendar year. In addition, the servicer is authorized to apply for adjustments to the CTC Charges at least 15 days before the end of each quarter if in the previous quarter the variance between the expected outstanding Transition Property principal balance and the actual outstanding principal balance exceeds the specified threshold.

[Attachment 1, the Company's Quarterly Servicer Certificate for the _____ quarter of ____, shows that the variance between the expected Transition Property outstanding balance and the actual outstanding balance exceeds the specified threshold. Therefore, in accordance with the Decision, the Company, as servicer of the Bonds, hereby revises the CTC Charges.]

PURPOSE

This filing establishes revised CTC Charges.

BACKGROUND

In the Decision, the Commission required the Company to make a True-Up Mechanism filing annually, at least 15 days before the end of the calendar year. In addition, the Commission authorized the Company to make a True-Up Mechanism filing on a quarterly basis, at least 15 days before the end of the calendar quarter, whereby the Company uses the methodology authorized by the Commission in the Decision and established in the Tariff filed on ________________ pursuant to the Decision to revise existing CTC Charges.

Using the methodology approved by the Commission in the Decision and the above referenced tariff, this filing modifies the variables used in the CTC Charges calculations and provides the resulting modified CTC Charges. Table I shows the revised assumptions for each of the variables used in calculating the CTC Charges. Attachment 2 shows the revised collection schedule for the Transition Property.

TABLE I **Input Values for Revised CTC Charges**	
Expected monthly residential kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly general service kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly large light and power/special contracts kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly lighting kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly public authority – firm kWh sales	
[Insert separate line for each of the next 12 months]	
Expected monthly public authority – interruptible kWh sales	
[Insert separate line for each of the next 12 months]	
Percent of revenue requirement allocated to residential customers	
Percent of revenue requirement allocated to general service customers	
Percent of revenue requirement allocated to large light and power/special contracts customers	
Percent of revenue requirement allocated to lighting customers	
Percent of revenue requirement allocated to public authority – firm customers	
Percent of revenue requirement allocated to public authority – interruptible customers	
Percent of residential customers' billed amounts expected to be uncollected	
Percent of general service customers' billed amounts expected to be uncollected	
Percent of large light and power/special contracts customers' billed amounts expected to be uncollected	
Percent of lighting customers' billed amounts expected to be uncollected	
Percent of public authority – firm customers' billed amounts expected to be uncollected	
Percent of public authority – interruptible customers' billed amounts expected to be uncollected	
[Insert the following six lines for each customer class (assumes that	

bills are written off after 6 months nonpayment)]	
Percent of billed amounts expected to be collected in current month	
Percent of billed amounts expected to be collected in second month after billing	
Percent of billed amounts expected to be collected in third month after billing	
Percent of billed amounts expected to be collected in fourth month after billing	
Percent of billed amounts expected to be collected in fifth month after billing	
Percent of billed amounts expected to be collected in sixth month after billing	
Expected Transition Property outstanding balance as of __/__/__**[First day of the next quarter]**	

Table II shows the revised CTC Charges calculated for each class of customer.

TABLE II	
Residential Customer CTC Charge	¢/kWh
General Service Customer CTC Charge	¢/kWh
Large Light and Power/Special Contracts Customer CTC Charge	¢/kWh
Lighting Customer CTC Charge	¢/kWh
Public Authority – Firm Customer CTC Charge	¢/kWh
Public Authority – Interruptible Customer CTC Charge	¢/kWh

The revenue requirement has been allocated among classes of customers on the basis of Section 2 of the Formula Schedule attached to the tariff filed on ________________.

EFFECTIVE DATE

In accordance with the Decision, True-Up Mechanism filings for annual CTC Charges adjustments shall be filed at least 15 days before the end of the calendar year, and these adjustments to CTC Charges shall be effective at the beginning of the next calendar year. In accordance with the Decision, True-Up Mechanism filings for quarterly CTC Charges adjustments shall be filed at least 15 days before the end of a calendar quarter and these adjustments to CTC Charges shall be effective at the beginning of the next calendar quarter. No further action of the Commission is required. Therefore, these CTC Charges shall be effective ___ 1, [year].

NOTICE

Copies of this filing are being furnished to ________________.

Attachment 1
Tucson Electric Power Company's Quarterly Servicer Certificate

Date: [End of calendar quarter preceding the True-Up Mechanism filing]

Expected Transition Property Principal Amount:

Actual Transition Property Principal Amount:

Principal Amount Difference:

Percentage Difference:

Attachment 2
Revised Scheduled Collection for Transition Property[1]

Date	Principal	Interest	Total
[Monthly]			

[1] Determined in accordance with Section 1 of the Formula Schedule.

MEMORANDUM OF UNDERSTANDING BETWEEN ARIZONA PUBLIC SERVICE COMPANY AND TUCSON ELECTRIC POWER COMPANY

The purpose of this memorandum of understanding ("MOU") is to confirm the understanding between ARIZONA PUBLIC SERVICE COMPANY ("APS"), and TUCSON ELECTRIC POWER COMPANY ("TEP") regarding the transaction set forth below.

1. **Recitals**:

1.1. In connection with its Application for approval of its Plan for Stranded Cost Recovery filed with the Arizona Corporation Commission ("ACC") pursuant to A.A.C. R-14-2-1607, et. seq., TEP has proposed to divest all of its generation assets, including, without limitation, TEP's interest in the Navajo Generating Station located in Page, Arizona ("Navajo") and the Four Corners Generating Units 4 and 5 located near Farmington, New Mexico ("Four Corners"), all of which are more particularly described on Attachment A ("Generating Assets");

1.2. APS is willing to divest its 345kV and 500kV transmission system facilities and associated rights of way, which are more particularly described on Attachment B (the "Transmission Assets") only as part of, and conditioned upon, a comprehensive settlement ("APS Settlement Agreement") with the ACC Staff that requires such divestment to a third party, and that satisfactorily resolves a number of competition-related issues, and that is approved by an ACC order in form and substance satisfactory to APS as more fully described below; and

1.3. The Parties desire to outline in this MOU the principles that will form the basis for negotiation of definitive terms and conditions pursuant to which the Parties will exchange TEP's Generation Assets for APS's Transmission Assets (the "Transaction").

2. **Exchange of Assets Between APS and TEP**:

At the Closing, as defined below, APS will transfer to TEP the Transmission Assets and TEP will transfer to APS the Generation Assets. In addition, subject to any consent requirements, APS shall transfer and assign to TEP and TEP shall assume the obligations associated with all existing agreements for transmission service over the Transmission Assets. To the extent there is a difference between the agreed upon fair market values of the Transmission Assets and Generation Assets, such difference will be paid in the form of cash at Closing, as defined below, by the Party transferring the assets with the lower value. The Transaction shall also include a power purchase agreement providing for unit contingent power sales from APS to TEP, as more fully described in Section 6 below ("Power Purchase Agreement").

3. **Closing:**

Subject to the terms and conditions set forth in the Definitive Agreement, the closing of the Transaction (the "Closing") is estimated to be on or before January 2, 2001. To the extent any condition precedent set forth in the Definitive Agreement, including those enumerated in Section 7 of this MOU, has not been satisfied by January 2, 2001, the Closing will be extended by mutual consent of the Parties to a date by which the Parties reasonably believe that such condition precedent will be satisfied. In the event all conditions have not been satisfied or waived by the applicable Party or Parties by December 31, 2002, the Definitive Agreement between the Parties shall terminate.

4. **Definitive Agreement:**

The completion of the Transaction is subject to the execution by the Parties of an agreement, which will be based on the principles set forth herein and which will include mutually agreeable and comprehensive terms, conditions, representations, warranties, indemnities, and covenants with respect to the Transaction and structure (the "Definitive Agreement") on or before 60 days from the date that the ACC enters both the APS Order and TEP Order, as described herein. The obligation of APS to enter into the Definitive Agreement is subject to the receipt by APS of a final Order, not subject to appeal, which adopts the APS Settlement Agreement , which in form and substance is satisfactory to APS ("APS Order"). The obligation of TEP to enter into the Definitive Agreement is subject to the receipt by TEP of a final Order, not subject to appeal, which adopts a settlement with the ACC regarding TEP's Plan for Stranded Cost Recovery pursuant to A.A.C. R-14-2-1607 et. seq ("TEP Order"). The Parties agree to negotiate in good faith to reach a Definitive Agreement within the 60 day period described above, provided, however, such time may be extended by mutual agreement of the Parties. In the event APS and TEP do not obtain the aforementioned Orders by December 15, 1998, or any mutually agreeable extension thereof, either Party may terminate this MOU by providing written notice to the other Party and neither Party shall have any obligation or liability hereunder.

5. **Asset Valuation**

For purposes of the Transaction the value of the Transmission Assets will be the book value at the date of Closing, which is estimated to be approximately $162 million as of July, 1998; and the value of the Generation Assets is $165 million as of January 1, 2001. The fair market values are based on the Transaction being subject to the terms and conditions outlined in this MOU; the asset descriptions contained in Attachments A and B; and assumptions that the physical condition of the Assets will not materially impair their operation or efficiency as of the Closing date. Fair market values will be subject to adjustments based on the final schedule of assets to be transferred; inventories of equipment; and due diligence inspection of the physical condition of the Assets and those rights and obligations to be transferred as part of the Transaction. In the event that any of the Assets cannot be transferred because of the exercise by any third party of a right of first refusal to purchase a portion of such Assets, the fair market value of such Assets shall be adjusted in proportion to the amount of assets being transferred. The above values with respect to the Generation Assets do not include any reserves for reclamation claims through the date of Closing. Such reserves will be funded by a cash payment to APS at Closing, if the amount of such reserves have been definitively determined, or by establishment of an escrow reserve fund to be agreed upon by the parties and to be funded in cash by TEP at Closing. Fuel, material and supplies will be transferred at book value at the time of Closing.

6. Power Purchase Agreement and Transmission O&M

6.1. At Closing the parties will enter into a Power Purchase Agreement which will provide for unit contingent power sales from APS to TEP from the Generation Assets. The Power Purchase Agreement will be based on the terms and conditions set forth in Attachment C.

6.2. In negotiating the Definitive Agreement the Parties will discuss the desirability of, and terms and conditions under, which APS would continue to provide certain O&M support functions for the Transmission Assets for a period subsequent to Closing.

7. Conditions Precedent to Closing:

7.1. The Definitive Agreement shall provide that Closing of the Transaction shall be subject to certain conditions, which must be satisfied prior to Closing. Each Party agrees to use its best efforts to satisfy the conditions precedent applicable to it prior to the Closing. In addition to any other conditions the Parties may agree upon, conditions to Closing will include the following:

7.2. Mutual Conditions Precedent:

7.2.1. Receipt of any necessary FERC approval of the Transaction, including transfer of transmission assets pursuant to § 203 of the Federal Power Act.

7.2.2. Receipt of FERC approval of a transmission pricing structure as described in Section 8 of this MOU.

7.2.3. Receipt of any necessary ACC approval of the Transaction.

7.2.4. Any consents or approvals of other regulatory agencies and third Parties necessary to consummate the Transaction as contemplated in the Definitive Agreement.

7.2.5. Absence of any pending or threatened litigation or adverse regulatory proceeding with respect to the APS Order, the TEP Order or the Transaction.

7.2.6. Absence of any material adverse change in the physical condition or value of the Transmission Assets and Generation Assets between the date of the Definitive Agreement and the Closing.

7.3. **APS Conditions Precedent**

7.3.1. Receipt of such consents or approvals as may be required to effect the transfer of the Transmission Assets, including satisfaction of any rights-of-first-refusal held by the other participants in the Transmission Assets.

7.3.2. Replacement of APS as Operating Agent for the Navajo Project Southern Transmission System, the Four Corners 500kV and 345kV Switchyards, and the Palo Verde/North Gila 500kV line.

7.3.3. Execution of the Power Purchase Agreement by both Parties.

7.3.4. Receipt of satisfactory fairness opinions and/or independent appraisals and approval of its Board of Directors.

7.4. **TEP Conditions Precedent**

7.4.1. Receipt of such consents or approvals as may be required to effect the transfer of TEP's ownership interest in Four Corners and Navajo, including satisfaction of any rights-of-first-refusal held by the other participants in the Navajo Project and the Four Corners Project.

7.4.2. An order by the ACC which will allow TEP to recover in rates its costs under the Power Purchase Agreement.

7.4.3. Appointment of TEP as Operating Agent for the Navajo Project Southern Transmission System, the Four Corners 500kV and 345kV Switchyards, and the Palo Verde/North Gila 500kV line.

7.4.4. Receipt of satisfactory fairness opinions and/or independent appraisals and approval of its Board of Directors.

7.5. All regulatory and third party consents and approvals shall be satisfactory to each Party in form and substance.

8. Transmission Pricing:

In their applications to FERC for approval of the sale of the Transmission Assets and the Open Access Transmission Tariff by which APS will receive service over the Transmission Assets, the Parties will develop and present to FERC a transmission pricing structure for the use of such assets that will not increase rates to customers in the Parties' current service territories. APS will enter into a Service Agreement with TEP relating to APS' use of the Transmission Assets under an Open Access Transmission Tariff accepted by FERC. This Open Access Transmission Tariff shall contain zonal rates developed for the use of EHV transmission facilities pursuant to which the transmission rates for any transmission user in either Party's current service territory, including APS' merchant group, shall not be adversely affected by the transfer of the Transmission Assets. The Tariff will also preserve and recognize the rights of transmission users under their existing transmission agreements with the Parties. Where APS transmission users are receiving service under a single agreement for both the Transmission Assets and the lower voltage transmission assets to be retained by APS, the Parties will agree to bifurcate those obligations in a manner that will not result in any cost shifting or increase in transmission costs to such users or APS.

9. Exclusivity:

Unless and until this MOU is terminated pursuant to its terms, and subject to the requirements associated with rights-of-first refusal held by other participants in jointly owned projects in which the Parties are also participants, the Parties shall not, directly or indirectly, solicit or entertain offers from, negotiate with, or in any manner encourage, discuss, accept, or consider any proposal of any other person relating to the acquisition of the Assets, in whole or in part. Notwithstanding the foregoing, the Parties understand and agree that if all or any portion of the Transmission Assets are not transferred to TEP due to a failure to satisfy any of the conditions set forth in Section 7 above or in the Definitive Agreement, APS will, in accordance with the terms of the APS Settlement Agreement, divest those Transmission Assets to a third party upon such terms and conditions as APS, in its sole and absolute discretion, determines to be appropriate and TEP shall not take any action to prevent such divestiture. The Parties further understand and agree that if all or any portion of the Generation Assets are not transferred to APS due to a failure to satisfy any of the conditions set forth in Section 7 above or in the Definitive Agreement, TEP will, in accordance with the terms of the TEP Order, divest those Generation Assets to a third party upon such terms and conditions as TEP, in its sole and absolute discretion, determines to be appropriate and APS shall not take any action to prevent such divestiture

10. Confidentiality:

The Parties agree to continue to abide by the terms of the Confidentiality Agreement between the Parties dated September 23, 1998.

11. Costs:

Each Party shall be responsible for and bear all of its own costs and expenses (including any broker's or finder's fees and the expenses of its Representatives) incurred at any time in connection with the negotiation of the Definitive Agreement and the pursuit or consummation of the Transaction.

12. Entire Agreement:

This MOU constitutes the entire agreement between the Parties, and supersedes all prior oral or written agreements, understandings, representations and warranties, and courses of conduct and dealing between the Parties on the subject matter hereof. Except as otherwise provided herein, this MOU may be amended or modified only by a writing executed by both Parties.

13. Signature Clause:

The signatories hereto represent that they have been appropriately authorized to enter into this Agreement in Principle on behalf of the Party for whom they sign. This MOU is hereby executed as of this 4th day of November, 1998.

ARIZONA PUBLIC SERVICE COMPANY

By Jack Davis

Its President

TUCSON ELECTRIC POWER COMPANY

By

Its Vice President

ATTACHMENT A

Generation Assets of TEP

Navajo Generating Station

All of Tucson Electric Power Company's right, title, interest, and assets in the Navajo Project and the Navajo Project Agreements including, but not limited to, those specific interests as set forth in Sections 5.19, 6 and 7 of the Navajo Project Co-Tenancy Agreement, as amended; excluding therefrom, however, any right, title, and interest in facilities or agreements relating to the transmission of electricity in excess of 230kV from the Navajo Generating Station.

1. Adequate SO2 allowances to operate the generation facilities for their remaining life..

2. Three steam electric generating units (Unit 1, Unit 2 and Unit 3), each of which shall have a nameplate rating of 750,000 kw and shall be a tandem-compound, four flow, single reheat, turbine-generator unit with initial steam conditions of 3500 psig and 1000° F, including three pulverized coal-fired, super-critical steam generator units.

3. All auxiliary equipment associated with said units.

4. An administration building, machine shop and warehouse to be located adjacent to the power plant.

5. A pumping station and all associated equipment to be located on the Colorado River.

6. 500 kv step-up transformers and all equipment associated therewith up to the point where the leads from the said transformers terminate at the generator isolating 500 kv disconnect switch structures in the Navajo 500 kv Switchyard.

7. Standby auxiliary power transformation equipment and related facilities.

8. Plant control and communication facilities and associated buildings or equipment.

9. Railroad approximately 80 miles in length extending from within the Rail Loading Site into the Navajo Plant Site, rolling stock, related facilities and equipment.

10. All improvements owned by the Co-Tenants within the Ash Disposal Area, Pumping Plant Site and Rail Loading Site.

11. All land and land rights acquired under the Indenture of Lease, the §323 Grants and the Contract and Grant of Easement from the United States for Water Intake and Discharge Facilities.

Four Corners Facilities

All of Tucson Electric Power Company's right, title, interest, and assets in the Enlarged Four Corners Generating Station and the Four Corners Project Agreements including, but not limited to, those specific interests as set forth in Sections 6, 7, and 8 of the Four Corners Project Co-Tenancy Agreement, as amended; excluding therefrom, however, any right, title, and interest in facilities or agreements relating to the transmission of electricity in excess of 230kV from the Enlarged Four Corners Generating Station.

All SO2 allowances allotted to TEP's interest in the Four Corners Project.

Steam Electric Generating Units 4 and 5 and their associated switchyard facilities shall consist principally of two 755 mw class 3500 psig, 1000 F with reheat to 1000 F, cross-compound, 3600/1800 rpm, double flow, outdoor turbine-generator units, complete with accessories; two pressurized type, super-critical-pressure steam generating units, designed for burning pulverized coal as primary fuel with natural gas available for ignition fuel, complete with accessories; 345-500 kV tie transformers; reserve auxiliary power source; and other items required for the complete generating installation, excluding the Common Facilities and Related Facilities allocated thereto.

Common Facilities For Enlarged Four Corners Generating Station:

1. Land Rights, including Lease Payments during Construction, Right-of-Way Expense and Surveys.

2. Clearing Site of Brush and Rough Grading.

3. Landscaping and Planting Adjacent to Service Building.

4. Yard Finish Grading of Plant Areas not Requiring Paving or Gravel Surfacing.

5. Plant Access Road, including Subbase, Surfacing, Auxiliary Dike, Culverts and Asphalt Coat from San Juan Bridge to BIA Canal.

6. River Access Road, including Subbase, Gravel Surfacing, Pipeline Bridge Crossing, Culverts and Riprap.

7. Plant Area Roads, including Asphaltic Surfaced, Gravel Based and Other Gravel Surfaced Roads.

8. Cement and Asphaltic Paving in Operating and Parking Areas, including Curbing.

9. Concrete Walks at the Service Building, Warehouse and Circulating Water Intake Area.

10. Plant Area Chain Link Fence, Remote Controlled Main Gate, Manual Gates and Barbed Wire Fence.

11. Yard Lighting Standards, Conduit, Cable, Foundations and Lamps.

12. Fire Protection Pumps, Piping with Excavation and Backfill, Valves, Hydrants and Hose Carts with Hoses and Nozzles.

13. Sanitary Sewer System, including Cast Iron and Clay Sewer Lines, Manholes, Septic Tank and Accessories.

14. Service Water System Chlorinator, Coagulator, Filters, Pumps, Yard Piping, Foundations and Domestic Water Lines.

15. Service and Shop Building Foundation, Walls, Doors, Windows, Heating and Ventilating Equipment, Plumbing, Toilet Facilities and Lighting.

16. Warehouse Foundation, Floor Slab Superstructure and Lighting.

17. Miscellaneous Buildings, Foundations, Floor Slabs, Superstructures and Lighting.

18. Coal Mobile Equipment, includes Hough D500 Paydozer.

19. Cooling Pond Dam, Spillway, Blowdown Structure, Intake Canal, Curtain Wall and Temperature Recorders.

20. Concrete Intake Structure Excavation, Backfill, Caissons and Concrete Structure for Service Water Pumps and Fire Pumps.

21. Hoist Structure and Hoist for Intake Area.

22. Screens and Stoplogs for Service Water and Fire Pumps.

23. Miscellaneous Equipment for Service Water and Fire Pumps.

24. Concrete Cribbing between Intake Structure and Canal Bank.

25. Circulating Water Discharge Canal to Cooling Pond.

26. River Pumping Plant, includes River Weir, Sluiceway, Pump Chamber, Gates, Stoplogs, Pumps, Motors, Lube Water Cooling System, Freeze Protection, Switchgear, Motor Control Center, Transformers, Lighting, Equipment Building, 69-kv Transmission Line, Power Supply, Fence, Gates, Make-up Water Line, Metering Station and Canal.

27. Circulating and Service Water Intake Motor Control Center.

28. General Services Transformers for Area Lighting, Service Water Pump No. 2, Freeze Protection, Fire Booster Pump, etc.

29. Intake Area Transformer for Water Treatment Building, Fire Pump No. 1 Service Water Pumps No. 1 and No. 3, Service Building, Area Lighting, Freeze Protection, etc.

30. Station Lighting Transformers.

31. Station Grounding and Cathodic Protection Systems, including Rectifier, Anode Bed, Ground Rods and Ground Cable.

32. Freeze Protection Strip and Unit Heaters, Heating Cables, Controls and Panels.

33. Underground Manholes, Handholes and Conduit, including Excavation, Backfill and Concrete Envelope.

34. Miscellaneous Power Plant Equipment, including Portable Cranes and Hoists, Fire Extinguishers, Vacuum Cleaner, Weather Station, Office Equipment, Garage Equipment, Stores Equipment, Shop Equipment, Laboratory Equipment, Small Tools, Kitchen Equipment, Testing Equipment and Forklift.

35. 69-kv and 230-kv Switchyard Common to River Pumping Station, including Portion of Site Improvement, Structures, Bus Conductors, Transformers, Oil Circuit Breakers, Air Switches, Lighting Protection, Panels, Wiring, Conduits, Ducts, Manholes, Grounding and Shielding.

36. ntra-site Communication (Gai-tronic and PAX Telephones Service Common Facilities).

37. Spare Parts for Above Facilities.

Related Facilities:

1. <u>Coal Handling System</u>

From the point of the Utah Mining termination at the surge bins down to the gates in the bottom of the bins, including chutes, gates, motor control center enclosure, and surge bins. Includes writing, lighting, foundations, dust control, CO_2 blanketing, electrical feed and control, structure, stairs and platforms.

2. Machine Shop Structure

   Structure, foundation, lighting, wiring, doors, heating and ventilating equipment, and plumbing, toilet, and shower facilities.

3. Modifications to Service Building

   Structural changes, walls, doors, windows, heating and ventilating equipment, lighting, and wiring.

4. Vehicle Bridge Over Intake Canal

   Structure, guard rail, pipe supports and surfacing.

5. Reroute Access Road Through Units 4 and 5 Area

   Subbase, base material, surfacing and culverts.

6. Modifications to River Pumping Station and Make-up Pipeline

   Structures, foundations, pumps, motors, electrical supply facilities, valves, piping and control apparatus for pump station and relocated section of 36-inch make-up pipeline, new 2-inch pipeline for river pump packing gland water, paving of roads and parking area and barricades for protection from earth slides.

7. Mobile Equipment Maintenance Building

   Foundation, floor slab, superstructure and lighting and repair equipment.

8. Miscellaneous Power Plant Equipment

   Small tools, machine shop tools, laboratory equipment, lockers, bins, shelving, portable fire fighting equipment, etc.

9. Enlargement of Discharge Canal

   Excavation to enlarge channel for discharging circulating water to lake and protection from erosion of channel walls.

10. Combustibles Storage Building

    Foundation, floor slab, repairs to superstructure, and lighting.

11. Station Mobile Equipment

Hydraulic crane, forklift trucks, small electric vehicles, and bicycles.

12. Plant Access Road

Access road, including subbase preparation, base material, asphalt surfacing, culverts and drainage facilities from BIA Canal to the station gate.

13. Coal Sampling Building and Equipment

Sampling building structure from point of connection with the surge bin structure including foundations, stairs, lighting, power facilities, dust control facilities, hearing and ventilating sampling equipment, sample preparation room with furnishings.

14. Wind Velocity and Direction Instruments

Wind velocity and direction instruments, wiring conduit and recorders.

15. River Water Solids Measuring Equipment

Flow recorder, conductivity recorder and cells, conduit, wiring and supports.

16. Warehouse

Structure, floor slab, lighting, heating and ventilating equipment, plumbing and office facilities.

17. New Administration Building

Structure, foundation, lighting, windows, heating and ventilating equipment.

18. Guardhouse – Main and Satellite

Structure, foundation, lighting, doors, heating and ventilating equipment.

19. Switchyard Shop

Structures, foundation, lighting, doors, heating and ventilating equipment and office facilities.

20. Shop 4 & 5

Structure, foundation, lighting, wiring, doors, heating and ventilating equipment, plumbing, toilet and shower facilities and office facilities.

21. Common Building

Structure, foundation, lighting, wiring, doors, heating and ventilating equipment, plumbing, toilet and shower facilities, office facilities and lunch room facilities.

22. Overhaul Shop

Structure, foundation, lighting, wiring, doors, heating and ventilating equipment, plumbing, toilet facilities and office facilities.

23. 150 Gallon Demineralizer

Structure, foundation, pumps, motors, electrical supply facilities and water treatment facilities.

24. National Pollution Discharge Elimination System (NPDES) Trench

Excavated canal and concrete lined trench.

25. Brine Concentrator and Related Capital Improvements

The brine concentrator and the capital improvements related thereto are part of the SO_2 removal project for Units 4 and 5 including the separator blowdown line and the chemical cleaning piping.

ATTACHMENT B

TRANSMISSION ASSETS

1. Cholla/Saguaro 500kV Line and rights-of-way
2. Cholla 500kV/345kV Switchyard and land rights
3. Saguaro 500kV Substation and land rights
4. Two Four Corners/Pinnacle Peak 345kV Lines and rights-of-way
5. Undivided interest in Four Corners345kV Switchyard and Project Agreements
6. Undivided interest in Pinnacle Peak 345kV Substation and land rights
7. Undivided interest in Four Corners 500kV Switchyard and Project Agreements
8. Preacher Canyon 345kV Substation and land rights
9. Undivided interest in Two Navajo/Westwing 500kV Lines, Project Agreements and land rights
10. Undivided interest in Navajo 500kV Switchyard, Project Agreements, and land rights
11. Undivided interest in Westwing 500kV Switchyard, Project Agreements, and land rights
12. Undivided interest in Yavapai 500kV Substation, Project Agreements, and land rights
13. Navajo Project breakers in Moenkopi 500kV Switchyard and Project Agreements
14. Navajo Project breakers, series capacitors, and a line reactor in the Moenkopi Switchyard
15. Undivided interest in Two Palo Verde/Westwing 500kV Lines, agreements, and rights-of-way
16. Undivided interest in Palo Verde 500kV Switchyard, agreements, and land rights
17. Undivided interest in Interconnection Agreement with Westwing 500kV Switchyard Participants
18. Undivided interest in Palo Verde/Kyrene 500kV Line, agreements, and rights-of-way
19. Undivided interest in Palo Verde/North Gila 500kV Line, agreements, and rights-of-way

20. Undivided interest in Interconnection Agreement with Palo Verde 500kV Switchyard Participants

21. Undivided interest in North Gila 500kV Substation, agreements, and land rights

22. Undivided interest in Mead/Phoenix 500kV Line, Project Agreements, and rights-of-way

23. Undivided interest in Perkins 500kV Substation, Phase Shifter, agreements, and land rights

24. Undivided interest in Mead 500kV Substation, agreements and land rights

25. Undivided interest in Marketplace 500kV Switchyard, agreements and land rights

26. Undivided interest in Market Place-Mead/Market Place – McCullough 500kV Line, agreements, and rights-of-way

27. Undivided interest in McCullough 500kV Switchyard, agreements, and land rights

28. Four Corners/El Dorado 500kV Line, Moenkopi Switchyard, Transmission Service Agreement with Southern California Edison Company, and rights-of-way

29. At substations, the ownership transition is at the high side of the transformer, except Pinnacle Peak and Four Corners.

ATTACHMENT C

POWER PURCHASE AGREEMENT

Terms Sheet

<u>Purchaser</u>: Tucson Electric Power Company

<u>Seller</u>: Arizona Public Service Company

<u>Amount</u>: 200MW

<u>Term</u>: 4 years, beginning January 1, 2001

<u>Average Price</u>:

	$/MWh
2001	$31
2002	$32
2003	$33
2004	$35

Price to be shaped on an on-peak/off-peak basis, based on a minimum load factor of 80% on-peak and 80% off-peak and a maximum load factor which will be determined by mutual agreement of the parties in the Power Purchase Agreement. The Seller may also offer pricing for the purchase of power in excess of the agreed maximums. The Power Purchase Agreement will also allow the minimum obligations, or capacity scheduled absent energy, to be satisfied through the payment of dollars. The minimum annual load factor shall be 80%.

<u>Contingency</u>: The 200MW will be pro-rated over the three Navajo Generating Station Units and the two Four Corners Project Units, and the availability of power and energy to Purchaser under the Power Purchase Agreement will be contingent on the operation of each of the five units at a level sufficient to provide its allocated share of the 200MW ("Unit Availability").

<u>Scheduling</u>: The Power Purchase Agreement will include monthly minimum and maximum capacity factors for scheduling purposes. The Purhcaser will have the right to schedule capacity and/or energy on an hourly basis pursuant to the pricing concepts described above.

<u>Balancing Account</u>: A year-to-year balancing account will be maintained through which any short falls in energy taken by Purchaser during a calendar year

will roll over into the following calendar year at the previous year's price.