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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
NOV 5 2015
DOCKETED BY

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01933A-15-0322

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TUCSON ELECTRIC POWER COMPANY

APPLICATION
TESTIMONY AND EXHIBITS

VOLUME 2 of 4

NOVEMBER 5, 2015

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TUCSON ELECTRIC POWER COMPANY

APPLICATION
TESTIMONY AND EXHIBITS

VOLUME 2 of 4

NOVEMBER 5, 2015

Direct Testimony of Dr. Ronald E. White

BEFORE THE
ARIZONA CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF
DR. RONALD E. WHITE
IN DOCKET NO. E-01933A-15-____

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am President of Foster Associates Consultants, LLC. Foster Associates is a public utility economic consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND.

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. degree in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Direc-

tors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the Midwest Finance Association, and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over 30 jurisdictions, including several appearances in Arizona. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communications Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is contained in Appendix REW–1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Foster Associates was engaged by Tucson Electric Power Company (TEP), a wholly–owned subsidiary of UNS Energy Corporation ("UNS Energy"), to conduct a 2015 depreciation rate study for electric plant subject to the jurisdiction of the Arizona Corporation Commission (ACC). The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates. The scope, findings and recommendations of the study are contained in Exhibit REW–1.

II. Development of Depreciation Rates

Q. PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. The service potential (or future economic benefit) of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other noncash expenses) or cash inflows attributable to the use of that asset alone. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life system) of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation,

deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of an accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated entity. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. PLEASE DESCRIBE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life and

curve descriptive of the parent population from which a plant account is viewed as a random sample. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is most often obtained from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current recorded reserve balance with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the sum of all reserves is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. Differences between theoretical and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments requiring an identification of reserves at a different level from that main-

tained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute or rebalance recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and net salvage rates. A redistribution of recorded reserves will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1 below.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

The above elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

III. 2015 DEPRECIATION RATE STUDY

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY TEP.

A. Depreciation rates currently used by TEP were adopted pursuant to a Settlement Agreement in Docket No. E–01933A–12–0291 (Decision No. 73912 Approving Set-

tlement Agreement dated June 27, 2013). The parties to the Agreement consented to adopt depreciation rates proposed by TEP in a 2012 depreciation study, based on December 31, 2011 plant and reserve balances..

Q. DID TEP PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2015 DEPRECIATION STUDY?

A. Yes. The database used in conducting the current study was obtained by appending plant and net salvage transactions for activity years 2012–2014 and age distributions of surviving plant at December 31, 2014 to the database used in conducting the 2012 study. The accuracy and completeness of the assembled database was verified for activity years 2012 through 2014 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2007 were verified in the 2007 and 2012 studies. Age distributions of surviving plant at December 31, 2014 were reconciled to the CPR.

Reserve transactions recorded over the period 1989–2014 were used in the 2015 study to derive appropriate net salvage rates for distribution facilities. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR TEP PLANT AND EQUIPMENT?

A. Yes. As discussed in Exhibit REW–1, distribution plant accounts were analyzed using a technique in which first, second and third degree orthogonal polynomials were fitted to a set of observed retirement ratios. The resulting functions were expressed as survivorship functions and numerically integrated to obtain an estimate of the projection life of a plant category. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and

curve for each plant category. Plant accounts classified in Steam and Other Production were identified by unit and treated as life–span categories in the 2015 study.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS IN THE 2015 STUDY?

A. Yes. Five–year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the study for distribution and general plant categories to a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from TEP operating personnel were blended with judgment and historical net salvage indications in developing estimates of the future. Independent contractors were retained by TEP to develop cost estimates for demolition and abatement of steam and other production generating stations.

Average net salvage rates for depreciable plant accounts were estimated using direct dollar weighting of historical retirements with historical net salvage rates, and future retirements (*i.e.*, surviving plant) with estimated future net salvage rates.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Statement C of Exhibit REW–1 provides a comparison of computed, recorded and rebalanced reserves at December 31, 2014. The sum of recorded reserves was $1,526,654,221 or 37.7 percent of the depreciable plant investment. The corresponding computed reserve is $1,549,014,457 or 38.3 percent of the depreciable plant investment. A proportionate amount of the measured reserve shortfall of $22,360,236 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates recommended in this study. Statement D of Exhibit REW–1 provides an estimate of the investment and net salvage components of the rebalanced reserves.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES?

A. Yes. A redistribution of recorded reserves is again considered appropriate for TEP. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED FOR TEP.

A. Current depreciation rates were developed for each primary account using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. The formulation of an account accrual rate using the currently approved system is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where both computed and recorded reserves are expressed as ratios to the plant in service.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM USED BY TEP?

A. No. Depreciation rates recommended in the 2015 study were developed using the currently approved system. It is the opinion of Foster Associates that this system will

remain appropriate for TEP, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

Q. ARE YOU GENERALLY FAMILIAR WITH THE NEAR–TERM PLANS FOR SAN JUAN UNIT 2 AND SUNDT COAL HANDLING FACILITIES?

A. Yes. It is my understanding that San Juan Unit 2 is scheduled to cease production by the end of 2017 and Sundt Unit 4 is scheduled to cease burning coal prior to the end of 2017. San Juan Unit 2 and the Sundt coal handling facilities will then be retired from service.

Q. WERE THESE NEAR–TERM RETIREMENTS CONSIDERED IN THE DEPRECIATION STUDY?

A. Yes. At the request of TEP, both San Juan Unit 2 and the Sundt coal handling facilities were treated as pro–forma retirements at December 31, 2014 and associated primary account recorded reserves were reduced by the pro–forma retirements. In the case of San Juan, the resulting debit reserve balances (totaling $110.1 million) were redistributed to Unit 1 and Common primary accounts in proportion to the distribution of computed reserves. The debit reserve balances for Sundt (totaling $24.7 million) were redistributed to Units 1 through 4 in proportion to the distribution of computed reserves. No reserve was redistributed to the Sundt solar booster (Areva).

IV. SUMMARY

Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS RECOMMENDED FOR TEP IN THE 2015 STUDY.

A. Table 2 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended in the study.

Function	Accrual Rate			2015 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.56%	3.65%	0.09%	$ 63,233,113	$ 64,730,459	$ 1,497,346
Other Production	3.27%	2.89%	-0.38%	18,005,482	15,925,600	(2,079,882)
Distribution	1.80%	1.80%	0.00%	25,066,136	25,101,719	35,583
General Plant	5.83%	5.89%	0.06%	19,194,724	19,383,557	188,833
Net Salvage (Dist.)	0.27%	0.25%	-0.02%	3,762,756	3,484,034	(278,722)
Total	3.19%	3.18%	-0.01%	$129,262,211	$128,625,369	($636,842)

Table 2. Current and Proposed Rates and Accruals

The composite accrual rate recommended for TEP electric operations is 3.18 percent. The current equivalent rate is 3.19 percent. The recommended change in the composite rate is a reduction of 0.01 percentage points.

A continued application of current rates would provide annualized depreciation expense of $129,262,211 compared with an annualized expense of $128,625,369 using the recommended accrual rates. The resulting 2015 expense reduction is $636,842.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Ronald E. White, Ph.D.

Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

2015 - Present Foster Associates Consultants, LLC
President

2007 - Present Foster Associates, Inc.
Chairman

1996 - 2007 Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February,

1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Testifying Witness

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01933A–12–0126, Tucson Electric Power Company.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc, testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842,

District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. *99*-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. RP14-118-000, WBI Energy Transmission, Inc.; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC*Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power

Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City

Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9385, Potomac Electric Power Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

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Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State

Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 201500213, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

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Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

South Dakota Public Utilities Commission, Docket No. EL14–106, NorthWestern Energy; testimony supporting revised depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

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Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-

Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

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Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

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Other Consulting Activities

Arbitrator in a Technical Dispute relating to classification of Capital Budget expenditures.

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, et. al. File No. 394126; testimony concerning depreciation and engineering economics.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues,

sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee.

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission,

Regulatory Information Systems Conference, September 1974.

Speaker

Depreciation Workshop, Oklahoma Corporation Commission, Public Utility Division, March 2015.

Depreciation Workshop, ONE Gas, Inc. January 2015.

Depreciation Training Seminar, Florida Public Service Commission, March 2013.

Depreciation and Obsolescence (Isness and Oughtness), Ninety–Fifth Annual Arizona Tax Conference, August 2012.

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Exhibit REW-1

Exhibit REW–1

2015 Depreciation Rate Study

Tucson Electric Power

foster associates

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EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2015 Depreciation Rate Study conducted by Foster Associates Consultants, LLC (Foster Associates) for electric plant owned and operated by Tucson Electric Power Company (TEP), a wholly–owned subsidiary of UNS Energy Corporation ("UNS Energy"). Work on the study commenced in June 2015 and progressed through late October at which time the project was completed.

Foster Associates is a public utility economic consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by TEP were adopted pursuant to a Settlement Agreement in Docket No. E–01933A–12–0291 (Decision No. 73912 Approving Settlement Agreement dated June 27, 2013). The parties to the Agreement consented to adopt depreciation rates proposed by TEP in a 2012 depreciation study, based on December 31, 2011 plant and reserve balances.

The principal findings and recommendations of the 2015 study are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain weighted–average net salvage rates. Statement F provides a computation of the estimated future net salvage rate for steam and other production facilities. Statement G contains the computation of terminal dismantlement costs for steam and other production facilities. Statement H provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains current and proposed statistics including average service lives, average remaining lives, and average net salvage rates.

SCOPE OF REVIEW

The principal activities undertaken in conducting the 2015 study included:

- Collection of plant and reserve data;
- Discussions with TEP plant accounting and operating personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been approved, TEP is currently using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is "retired" (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories.

RECOMMENDED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended in the current study.

Function	Accrual Rate			2015 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.56%	3.65%	0.09%	$63,233,113	$64,730,459	$1,497,346
Other Production	3.27%	2.89%	-0.38%	18,005,482	15,925,600	(2,079,882)
Distribution	1.80%	1.80%	0.00%	25,066,136	25,101,719	35,583
General Plant	5.83%	5.89%	0.06%	19,194,724	19,383,557	188,833
Net Salvage (Dist.)	0.27%	0.25%	-0.02%	3,762,756	3,484,034	(278,722)
Total	3.19%	3.18%	-0.01%	$129,262,211	$128,625,369	($636,842)

Table 1. Current and Proposed Rates and Accruals

The composite accrual rate recommended for TEP electric operations is 3.18 percent. The current equivalent rate is 3.19 percent. The recommended change in the composite rate is a reduction of 0.01 percentage points.

A continued application of current rates would provide annualized depreciation expense of $129,262,211 compared with an annualized expense of $128,625,369 using the recommended accrual rates. The resulting 2015 expense reduction is $636,842.

Of the 214 plant accounts included in the 2015 study, Foster Associates is recommending accrual rate reductions for 85 accounts, rate increases for 92 accounts and no change for 37 accounts.

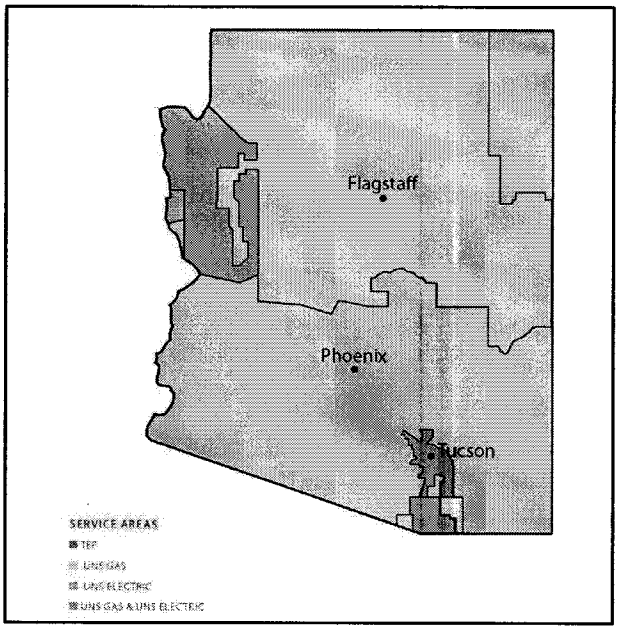
COMPANY PROFILE

GENERAL

Tucson Electric Power Company (TEP) is a vertically integrated, regulated utility that generates, transmits and distributes electricity. TEP also sells electricity to other utilities and power marketing entities located primarily in the western United States. TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis Inc. (Fortis) which is the largest investor-owned gas and electric distribution utility holding company in Canada.

SERVICE AREA

TEP's service territory covers 1,155 square miles with service to approximately 415,000 retail electric customers and includes a population of approximately one million people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.



DISTRIBUTION SYSTEM

The overhead electric distribution system is comprised of 2,600 circuit–miles of lower voltage primary lines. TEP owns approximately 77% of the poles on which the lower voltage lines are located. The underground electric distribution system includes 4,461 cable–miles of lines. Electric substation capacity consisted of 106 substations with a total installed transformer capacity of 15,809,050 kilovolt amperes.

GENERATING RESOURCES

At December 31, 2014, TEP owned or leased 2,448 MW of net generating capability, as set forth in Table 2 below.

Generating Source	Unit No.	Date in Service	Fuel Type	MW	Operating Agent	TEP's Share %	TEP's Share MW
Springerville Station [1]	1	1985	Coal	387	TEP	49.5	192
Springerville Station	2	1990	Coal	390	TEP	100.0	390
San Juan Station	1	1976	Coal	340	PNM	50.0	170
San Juan Station	2	1973	Coal	340	PNM	50.0	170
Navajo Station	1	1974	Coal	750	SRP	7.5	56
Navajo Station	2	1975	Coal	750	SRP	7.5	56
Navajo Station	3	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	1969	Coal.	785	APS	7.0	55
Four Corners Station	5	1970	Coal	785	APS	7.0	55
Gila River Power Station	3	2003	Gas	550	Ethos	75.0	413
Luna Generating Station	1	2006	Gas	555	PNM	33.0	185
Sundt Station	1	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station [2]	4	1967	Coal	120	TEP	100.0	120
Sundt Combustion Turbines		1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		2001	Gas/Oil	75	TEP	100.0	75
North Loop		2001	Gas	94	TEP	100.0	94
Springerville Solar Station		2002-2014	Solar	16	TEP	100.0	16
Tucson Solar Projects		2010-2014	Solar	12	TEP	100.0	12
Ft. Huachuca Project		2014	Solar	17	TEP	100.0	17
Total TEP Capacity [3]							2,448

Table 2. Generating Resources

[1]At December 31, 2014, TEP owned 96 MW of capacity at Springerville Unit 1 and continued to lease the remaining 291 MW of capacity. In January 2015, TEP purchased 96 MW of capacity bringing the total owned capacity to 192 MW. TEP's lease of the remaining 195 MW expired in January 2015.

[2]Sundt Station Unit 4 can be operated on either coal or natural gas. The table above reflects the nominal generating capacity assuming the unit is fueled by coal. If the Unit burns natural gas, it has a nominal capacity of 156 MW.

[3]Excludes 932 MW of additional resources, which consist of certain capacity purchases and interruptible retail load

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This study provides the foundation and documentation for recommended changes in depreciation rates used by TEP. The proposed rates are subject to approval by the Arizona Corporation Commission.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2015 study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. Age distributions of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of a study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in a life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a data base. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to a company's official plant records.

The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system currently used by TEP provides aged transactions over the period 1989–2014 for all plant accounts.

The database used in conducting the current study was obtained by appending plant and net salvage transactions for activity years 2012–2014 and age distributions of surviving plant at December 31, 2014 to the database used in conducting the 2012 study.[1] The accuracy and completeness of the assembled database was verified for activity years 2012 through 2011 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2007 were verified in the 2007 and 2012 studies. Age distributions of surviving plant at December 31, 2014 were reconciled to the CPR.

Reserve transactions recorded over the period 1989–2014 were used in the 2015 study to derive appropriate net salvage rates for distribution facilities. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of an account. Mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

[1] The database used in the 2015 study was initially constructed in 2004 when depreciation rates were developed by Foster Associates for non–local generation operations. The database was constructed to provide a reverse calculation of plant activity recorded over the period 1989–2003. Age distributions of plant exposed to retirement at the beginning of each activity year were derived by adding (or subtracting) transaction amounts to the coded age distributions of surviving plant at December 31, 2003.
The reverse–flow database was converted to a forward–flow file by a) coding December 31, 1998 derived age distributions as opening plant balances; b) coding post–1998 derived additions as recorded additions; and c) removing December 31, 2003 age distributions from the database. The conversion of the database from a reverse construction to a forward construction was undertaken to facilitate appending future activity years without removing or adjusting prior coded transactions.
The 2004 database was updated in the 2007 and 2012 studies by appending additional plant and net salvage transactions to the prior databases. The accuracy and completeness of the assembled databases were verified for each appended activity year by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance to the official plant records of the Company. Age distributions of surviving plant were reconciled to the CPR.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

Analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2015 study.

An actuarial life analysis program designed and developed by Foster Associates was used in the 2015 study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally contains the age of each survivor and the age of each retirement from a group of property units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. The ratio of retirements to exposures—called a "retirement ratio"—is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in the 2015 study are the Iowa–type curves mathematically

described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting functions were expressed as survivorship functions and numerically integrated to obtain an estimate of the projection life of a plant category. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and curve for each plant category.

The set of computer programs used in the NJNG study provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program designed and developed by Foster Associates include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides both tabular and graphics output to aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), retirement dispersion is also exhibited in plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span

method with interim retirements described by an appropriate survivor curve. Plant accounts classified in Steam and Other Production were identified by unit and treated as life–span categories in the 2015 study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a basis for estimating future salvage and cost of removal. However, consideration should be given to events that may cause deviations from net salvage realized in the past. Factors that should be considered include: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

Five–year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the 2015 study for distribution and general plant categories to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) provide a basis for estimating a future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates were estimated using direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with estimated future net salvage rates. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as the weighting of future net salvage estimates changes from the installation of subsequent plant additions.

Independent contractors were retained by TEP to develop cost estimates at December 31, 2011 for demolition and abatement of steam and other production planta.[2] Statement G provides a computation of terminal dismantlement costs used in Statement F to derive future net salvage rates for these production facili-

ties. The blending of interim and final net salvage rates is shown in Statement E.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve, which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant currently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifica-

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[2]The firm of Burns & McDonnell was retained to estimate the cost of dismantling steam generating units at Sundt, and Springerville (Units 1 and 2, Common Facilities, and Fuel Handling Facilities), as well as gas turbines at DeMoss Petrie, Sundt, North Loop, and Luna (in which TEP has a 1/3 interest).

The firm of Black & Veatch was retained in 2013 by Public Service Company of New Mexico to update dismantlement costs estimated in 2011 for San Juan Generating Station in which TEP holds 50 percent ownership interest in Units 1 and 2, and 19.8% ownership of Common Facilities.

The firm of Sargent & Lundy was retained to conduct dismantlement studies at the Navajo Generating Station in which TEP holds 7.5 percent ownership interest in Units 1, 2, 3 and the Common Facilities.

Shaw Environmental Inc. was retained by Arizona Public Service Company to estimate demolition costs in 2015 dollars for the Four Corners Generating Station of which TEP holds 7 percent ownership interest in Units 4 and 5, and 5.07 percent ownership of Common Facilities.

tions, total recorded reserves in relation to the sum of account computed reserves provides a meaningful indicator of the adequacy (or inadequacy) of recorded reserves. If statistical life studies have not been conducted or retirement dispersion has been overlooked in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences can also arise from plant accounting activity such as transfers and adjustments that may require an identification of reserves at a level lower than maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for TEP. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or generating plant unit) by the ratio of the function (or unit) total recorded reserve to the function (or unit) total calculated reserve. The sum of the redistributed reserves within a function (or generating unit) is, therefore, equal to the function (or unit) total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of computed, recorded and rebalanced reserves at December 31, 2014. The sum of recorded reserves was $1,526,654,221 or 37.7 percent of the depreciable plant investment. The corresponding computed reserve is $1,549,014,457 or 38.3 percent of the depreciable plant investment. A proportionate amount of the measured reserve shortfall of $22,360,236 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates recommended in this study. Statement D provides an estimate of the investment and net salvage components of the rebalanced reserves.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less

expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of a time–based method is that it does not require an estimate of the remaining amount of service potential an asset will produce or the amount of service potential actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2015 study were developed using the currently approved system composed of the straight–line method, vintage group procedure, remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique with amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that the current system will remain appropriate for TEP, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balanc-

es prior to posting retirements would overstate the annualized amortization expense. Accrual rates contained in Statement A have been applied to plant balances containing vintages that will be retired upon approval of the proposed amortization periods. Accrual rates contained in Statement A should be applied to current plant balances. Accrual rates equal to the reciprocal of the amortization period should be applied to these categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life and net salvage statistics recommended for a) steam production; b) other production; c) distribution plant; and d) general plant categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2015 depreciation accruals derived from an application of the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2014.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a computation of the estimated future net salvage rate for steam and other production facilities.
- Statement G contains the computation of terminal dismantlement costs for steam and other production facilities.
- Statement H provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by TEP for the mix of investments recorded at December 31, 2014. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Both current and proposed accrual rates are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

The formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description		Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION							
310.00	Rights-of-Way	3.03%		3.03%	2.85%		2.85%
311.00	Structures and Improvements	3.37%	0.33%	3.70%	3.17%	0.67%	3.84%
312.00	Boiler Plant Equipment	2.89%	0.38%	3.27%	3.03%	0.52%	3.55%
314.00	Turbogenerator Units	3.27%	0.72%	3.99%	3.29%	0.54%	3.83%
315.00	Accessory Electric Equipment	3.72%	0.94%	4.66%	3.07%	0.70%	3.77%
316.00	Miscellaneous Power Plant Equipment	3.34%	0.40%	3.74%	2.96%	0.41%	3.37%
Total Steam Production Plant		3.09%	0.47%	3.56%	3.09%	0.56%	3.65%
OTHER PRODUCTION							
Non-Solar							
341.00	Structures and Improvements	2.51%	0.31%	2.82%	2.58%	0.38%	2.96%
342.00	Fuel Holders, Products and Accessories	2.71%	0.31%	3.02%	2.66%	0.37%	3.03%
343.00	Prime Movers	2.36%	0.04%	2.40%	2.49%	0.22%	2.71%
344.00	Generators and Devices	2.13%	0.15%	2.28%	1.95%	0.18%	2.13%
345.00	Accessory Electric Equipment	2.34%	0.08%	2.42%	2.10%	0.17%	2.27%
346.00	Miscellaneous Power Plant Equipment	2.45%	0.27%	2.72%	2.51%	0.35%	2.86%
Total Non-Solar		2.33%	0.11%	2.44%	2.34%	0.23%	2.57%
Solar							
344.00	Generators and Devices	5.13%		5.13%	3.44%	0.17%	3.61%
Total Solar		5.13%		5.13%	3.44%	0.17%	3.61%
Total Other Production Plant		3.19%	0.08%	3.27%	2.68%	0.21%	2.89%
DISTRIBUTION PLANT							
360.RW	Rights-of-Way	1.43%		1.43%	1.41%		1.41%
361.00	Structures and Improvements	1.63%		1.63%	1.71%		1.71%
362.00	Station Equipment	1.46%		1.46%	1.66%		1.66%
364.00	Poles, Towers and Fixtures	1.63%		1.63%	1.66%		1.66%
365.00	Overhead Conductors and Devices	1.47%		1.47%	1.64%		1.64%
366.00	Underground Conduit	1.42%		1.42%	1.36%		1.36%
367.00	Underground Conductors and Devices	1.89%		1.89%	1.78%		1.78%
368.OH	Line Transformers - Overhead	1.84%		1.84%	1.75%		1.75%
368.UG	Line Transformers - Underground	2.52%		2.52%	1.97%		1.97%
369.OH	Services - Overhead	1.62%		1.62%	1.83%		1.83%
369.UG	Services - Underground	1.50%		1.50%	1.52%		1.52%
370.00	Meters	2.99%		2.99%	4.61%		4.61%
373.00	Street Lighting and Signal Systems	1.74%		1.74%	1.76%		1.76%
Total Distribution Plant		1.80%		1.80%	1.80%		1.80%
GENERAL PLANT							
Depreciable							
390.00	Structures and Improvements	2.49%	0.15%	2.64%	2.53%	0.15%	2.68%
392.C0	Transportation - Class 0	4.96%	-0.73%	4.23%	5.14%	-0.86%	4.28%
392.C1	Transportation - Class 1	12.43%	-1.81%	10.62%	12.97%	-2.20%	10.77%
392.C2	Transportation - Class 2	12.25%	-1.78%	10.47%	12.88%	-2.23%	10.65%
392.C3	Transportation - Class 3	10.71%	-1.56%	9.15%	11.49%	-2.02%	9.47%
392.C4	Transportation - Class 4	7.03%	-1.02%	6.01%	7.59%	-1.35%	6.24%
392.C5	Transportation - Class 5	7.31%	-1.08%	6.23%	7.87%	-1.31%	6.56%
392.C6	Transportation - Class 6	6.65%	-1.00%	5.65%	6.78%	-1.01%	5.77%
392.C7	Transportation - Class 7	6.98%	-1.04%	5.94%	7.20%	-1.08%	6.12%
392.C8	Transportation - Class 8	7.50%	-1.13%	6.37%	7.85%	-1.19%	6.66%
392.C9	Transportation - Class 9	4.66%	-0.70%	3.96%	4.02%	-0.61%	3.41%
396.00	Power Operatied Equipment	6.48%	-0.24%	6.24%	6.72%	-0.06%	6.66%
397.EM	EMS and SCADA Equipment	4.96%		4.96%	5.12%		5.12%
Total Depreciable		4.12%	-0.17%	3.95%	4.25%	-0.21%	4.04%

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Account Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
	A	B	C	D=B+C	E	F	G=E+F
	Amortizable						
391.00	Furniture and Office Equipment	← 24 Year Amortization →		4.15%	← 24 Year Amortization →		4.15%
391.20	Network and Data Equipment	← 5 Year Amortization →		18.68%	← 5 Year Amortization →		18.68%
393.00	Stores Equipment	← 15 Year Amortization →		6.35%	← 15 Year Amortization →		6.35%
394.00	Tools, Shop and Garage Equipment	← 17 Year Amortization →		5.72%	← 17 Year Amortization →		5.72%
395.00	Laboratory Equipment	← 17 Year Amortization →		5.78%	← 17 Year Amortization →		5.78%
397.20	Telecommunications Equipment	← 15 Year Amortization →		6.59%	← 15 Year Amortization →		6.59%
398.00	Miscellaneous Equipment	← 20 Year Amortization →		5.00%	← 20 Year Amortization →		5.00%
	Total Amortizable	8.75%		8.75%	8.75%		8.75%
	Total General Plant	5.94%	-0.11%	5.83%	6.01%	-0.12%	5.89%
	SUBTOTAL	2.89%	0.21%	3.10%	2.83%	0.26%	3.09%
	NET SALVAGE						
108.02	Distribution		0.28%	0.28%		0.25%	0.25%
	Total Net Salvage		0.27%	0.27%		0.25%	0.25%
	TOTAL UTILITY	2.89%	0.30%	3.19%	2.83%	0.35%	3.18%
	STEAM PRODUCTION (by Unit)						
	Four Corners						
310.00	Rights-of-Way						
311.00	Structures and Improvements	2.19%	0.17%	2.36%	2.47%	0.15%	2.62%
312.00	Boiler Plant Equipment	1.60%	0.15%	1.75%	1.57%	0.13%	1.70%
314.00	Turbogenerator Units	2.33%	0.14%	2.47%	2.06%	0.10%	2.16%
315.00	Accessory Electric Equipment	3.48%	0.19%	3.67%	4.04%	0.20%	4.24%
316.00	Miscellaneous Power Plant Equipment	2.39%	0.17%	2.56%	2.31%	0.13%	2.44%
	Total Four Corners	1.82%	0.15%	1.97%	1.80%	0.12%	1.92%
	Four Corners Unit 4						
310.00	Rights-of-Way						
311.00	Structures and Improvements	2.13%	0.16%	2.29%	2.35%	0.13%	2.48%
312.00	Boiler Plant Equipment	1.50%	0.16%	1.66%	1.43%	0.14%	1.57%
314.00	Turbogenerator Units	2.44%	0.12%	2.56%	2.08%	0.09%	2.17%
315.00	Accessory Electric Equipment	3.87%	0.17%	4.04%	3.91%	0.15%	4.06%
316.00	Miscellaneous Power Plant Equipment	2.34%	0.15%	2.49%	2.20%	0.11%	2.31%
	Total Four Corners Unit 4	1.78%	0.15%	1.93%	1.68%	0.13%	1.81%
	Four Corners Unit 5						
310.00	Rights-of-Way						
311.00	Structures and Improvements	2.26%	0.19%	2.45%	2.60%	0.17%	2.77%
312.00	Boiler Plant Equipment	1.70%	0.13%	1.83%	1.73%	0.10%	1.83%
314.00	Turbogenerator Units	2.17%	0.16%	2.33%	2.03%	0.12%	2.15%
315.00	Accessory Electric Equipment	3.07%	0.22%	3.29%	4.18%	0.25%	4.43%
316.00	Miscellaneous Power Plant Equipment	2.45%	0.20%	2.65%	2.43%	0.14%	2.57%
	Total Four Corners Unit 5	1.86%	0.14%	2.00%	1.93%	0.11%	2.04%
	Navajo						
310.00	Rights-of-Way	0.29%	0.02%	0.31%	0.77%	0.04%	0.81%
311.00	Structures and Improvements	1.43%	0.10%	1.53%	2.57%	0.14%	2.71%
312.00	Boiler Plant Equipment	1.66%	0.10%	1.76%	3.15%	0.16%	3.31%
314.00	Turbogenerator Units	1.51%	0.10%	1.61%	3.17%	0.16%	3.33%
315.00	Accessory Electric Equipment	1.87%	0.13%	2.00%	3.89%	0.21%	4.10%
316.00	Miscellaneous Power Plant Equipment	1.58%	0.11%	1.69%	2.85%	0.16%	3.01%
	Total Navajo	1.63%	0.10%	1.73%	3.14%	0.17%	3.31%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Navajo Unit 1						
310.00 Rights-of-Way						
311.00 Structures and Improvements	0.69%	0.05%	0.74%	4.13%	0.20%	4.33%
312.00 Boiler Plant Equipment	1.75%	0.12%	1.87%	6.00%	0.30%	6.30%
314.00 Turbogenerator Units	1.58%	0.09%	1.67%	6.04%	0.28%	6.32%
315.00 Accessory Electric Equipment	1.51%	0.09%	1.60%	8.48%	0.40%	8.88%
316.00 Miscellaneous Power Plant Equipment	0.67%	0.05%	0.72%	4.01%	0.19%	4.20%
Total Navajo Unit 1	1.61%	0.11%	1.72%	6.05%	0.30%	6.35%
Navajo Unit 2						
310.00 Rights-of-Way						
311.00 Structures and Improvements	0.99%	0.07%	1.06%	1.42%	0.09%	1.51%
312.00 Boiler Plant Equipment	1.52%	0.09%	1.61%	1.70%	0.10%	1.80%
314.00 Turbogenerator Units	1.60%	0.12%	1.72%	1.82%	0.12%	1.94%
315.00 Accessory Electric Equipment	1.62%	0.11%	1.73%	2.05%	0.13%	2.18%
316.00 Miscellaneous Power Plant Equipment	0.88%	0.06%	0.94%	0.97%	0.06%	1.03%
Total Navajo Unit 2	1.51%	0.10%	1.61%	1.73%	0.10%	1.83%
Navajo Unit 3						
310.00 Rights-of-Way						
311.00 Structures and Improvements	0.99%	0.07%	1.06%	1.12%	0.06%	1.18%
312.00 Boiler Plant Equipment	1.58%	0.08%	1.66%	1.83%	0.08%	1.91%
314.00 Turbogenerator Units	1.22%	0.07%	1.29%	1.42%	0.06%	1.48%
315.00 Accessory Electric Equipment	1.33%	0.11%	1.44%	1.57%	0.11%	1.68%
316.00 Miscellaneous Power Plant Equipment	0.73%	0.08%	0.81%	0.96%	0.09%	1.05%
Total Navajo Unit 3	1.44%	0.08%	1.52%	1.67%	0.08%	1.75%
Navajo Common						
310.00 Rights-of-Way	0.29%	0.02%	0.31%	0.77%	0.04%	0.81%
311.00 Structures and Improvements	1.91%	0.14%	2.05%	2.81%	0.17%	2.98%
312.00 Boiler Plant Equipment	2.19%	0.17%	2.36%	2.87%	0.20%	3.07%
314.00 Turbogenerator Units	3.86%	0.28%	4.14%	4.89%	0.29%	5.18%
315.00 Accessory Electric Equipment	3.49%	0.24%	3.73%	4.37%	0.25%	4.62%
316.00 Miscellaneous Power Plant Equipment	2.00%	0.13%	2.13%	3.34%	0.19%	3.53%
Total Navajo Common	2.23%	0.16%	2.39%	3.12%	0.20%	3.32%
San Juan						
310.00 Rights-of-Way						
311.00 Structures and Improvements	1.72%	0.15%	1.87%	7.58%	0.72%	8.30%
312.00 Boiler Plant Equipment	2.45%	0.74%	3.19%	7.64%	0.89%	8.53%
314.00 Turbogenerator Units	2.06%	0.18%	2.24%	7.58%	0.73%	8.31%
315.00 Accessory Electric Equipment	2.09%	0.19%	2.28%	7.63%	0.73%	8.36%
316.00 Miscellaneous Power Plant Equipment	1.58%	0.12%	1.70%	7.61%	0.70%	8.31%
Total San Juan	2.30%	0.56%	2.86%	7.62%	0.84%	8.46%
San Juan Unit 1						
310.00 Rights-of-Way						
311.00 Structures and Improvements	1.72%	0.15%	1.87%	7.57%	0.73%	8.30%
312.00 Boiler Plant Equipment	2.38%	0.25%	2.63%	7.63%	0.74%	8.37%
314.00 Turbogenerator Units	2.06%	0.18%	2.24%	7.58%	0.73%	8.31%
315.00 Accessory Electric Equipment	2.09%	0.19%	2.28%	7.63%	0.73%	8.36%
316.00 Miscellaneous Power Plant Equipment	1.59%	0.12%	1.71%	7.60%	0.72%	8.32%
Total San Juan Unit 1	2.25%	0.23%	2.48%	7.62%	0.73%	8.35%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
San Juan Common						
310.00 Rights-of-Way						
311.00 Structures and Improvements	1.66%	0.16%	1.82%	8.09%	0.02%	8.11%
312.00 Boiler Plant Equipment	3.76%	9.71%	13.47%	7.74%	3.76%	11.50%
314.00 Turbogenerator Units	2.30%	0.20%	2.50%			
315.00 Accessory Electric Equipment	2.10%	0.20%	2.30%			
316.00 Miscellaneous Power Plant Equipment	1.36%	0.12%	1.48%	8.09%		8.09%
Total San Juan Common	3.70%	9.46%	13.16%	7.75%	3.66%	11.41%
Springerville						
310.00 Rights-of-Way	3.04%		3.04%	2.85%		2.85%
311.00 Structures and Improvements	3.72%	0.05%	3.77%	2.84%	0.60%	3.44%
312.00 Boiler Plant Equipment	3.16%	0.07%	3.23%	2.12%	0.39%	2.51%
314.00 Turbogenerator Units	2.97%	0.08%	3.05%	2.18%	0.14%	2.32%
315.00 Accessory Electric Equipment	3.30%	0.08%	3.38%	1.90%	0.19%	2.09%
316.00 Miscellaneous Power Plant Equipment	3.99%	0.06%	4.05%	2.25%	0.24%	2.49%
Total Springerville	3.22%	0.07%	3.29%	2.22%	0.36%	2.58%
Springerville Unit 1						
310.00 Rights-of-Way						
311.00 Structures and Improvements	7.97%	0.01%	7.98%	2.06%	0.08%	2.14%
312.00 Boiler Plant Equipment	6.15%	0.03%	6.18%	1.98%	0.08%	2.06%
314.00 Turbogenerator Units	5.77%	-0.05%	5.72%	1.97%	0.08%	2.05%
315.00 Accessory Electric Equipment	6.08%	0.01%	6.09%	1.73%	0.08%	1.81%
316.00 Miscellaneous Power Plant Equipment	8.69%		8.69%	2.14%	0.07%	2.21%
Total Springerville Unit 1	6.24%	0.01%	6.25%	1.97%	0.08%	2.05%
Springerville Unit 1 Common						
310.00 Rights-of-Way				2.03%		2.03%
311.00 Structures and Improvements	3.00%	0.01%	3.01%	2.04%	0.24%	2.28%
312.00 Boiler Plant Equipment	4.24%		4.24%	2.00%	0.26%	2.26%
314.00 Turbogenerator Units	1.83%		1.83%	1.93%	0.26%	2.19%
315.00 Accessory Electric Equipment	4.35%		4.35%	1.81%	0.30%	2.11%
316.00 Miscellaneous Power Plant Equipment	3.72%		3.72%	1.83%	0.28%	2.11%
Total Springerville Unit 1 Common	3.34%	0.01%	3.35%	2.00%	0.25%	2.25%
Springerville Unit 2						
310.00 Rights-of-Way						
311.00 Structures and Improvements	1.86%	0.15%	2.01%	2.16%	0.15%	2.31%
312.00 Boiler Plant Equipment	1.88%	0.14%	2.02%	2.12%	0.15%	2.27%
314.00 Turbogenerator Units	1.84%	0.14%	1.98%	2.25%	0.15%	2.40%
315.00 Accessory Electric Equipment	1.69%	0.13%	1.82%	1.88%	0.12%	2.00%
316.00 Miscellaneous Power Plant Equipment	1.71%	0.11%	1.82%	2.14%	0.13%	2.27%
Total Springerville Unit 2	1.85%	0.14%	1.99%	2.13%	0.15%	2.28%
Springerville Unit 2 Common (Leasehold Imp.)						
310.00 Rights-of-Way	2.80%		2.80%	3.86%		3.86%
311.00 Structures and Improvements	4.34%	0.01%	4.35%	5.38%	2.00%	7.38%
312.00 Boiler Plant Equipment	5.50%		5.50%	6.45%	2.16%	8.61%
314.00 Turbogenerator Units	4.06%		4.06%	4.69%	1.85%	6.54%
315.00 Accessory Electric Equipment	3.06%		3.06%	4.01%	1.58%	5.59%
316.00 Miscellaneous Power Plant Equipment	4.37%		4.37%	5.19%	2.01%	7.20%
Total Springerville Unit 2 Common	4.34%	0.01%	4.35%	5.36%	1.89%	7.25%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2014)			Proposed (at 12/31/2014)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Springerville Coal Handling						
310.00 Rights-of-Way	5.44%		5.44%	2.04%		2.04%
311.00 Structures and Improvements						
312.00 Boiler Plant Equipment	1.65%		1.65%	2.14%	1.24%	3.38%
314.00 Turbogenerator Units						
315.00 Accessory Electric Equipment						
316.00 Miscellaneous Power Plant Equipment						
Total Springerville Coal Handling	1.70%		1.70%	2.14%	1.22%	3.36%
Sundt						
310.00 Rights-of-Way						
311.00 Structures and Improvements	3.91%	2.04%	5.95%	3.03%	1.45%	4.48%
312.00 Boiler Plant Equipment	3.73%	1.76%	5.49%	2.81%	1.19%	4.00%
314.00 Turbogenerator Units	6.15%	3.63%	9.78%	3.66%	2.01%	5.67%
315.00 Accessory Electric Equipment	5.67%	3.17%	8.84%	3.73%	1.94%	5.67%
316.00 Miscellaneous Power Plant Equipment	6.31%	3.45%	9.76%	4.00%	2.10%	6.10%
Total Sundt	4.58%	2.42%	7.00%	3.17%	1.51%	4.68%
Sundt Unit 1						
310.00 Rights-of-Way						
311.00 Structures and Improvements	9.95%	5.37%	15.32%	4.99%	2.77%	7.76%
312.00 Boiler Plant Equipment	10.40%	5.02%	15.42%	4.54%	2.37%	6.91%
314.00 Turbogenerator Units	11.68%	6.16%	17.84%	4.98%	2.71%	7.69%
315.00 Accessory Electric Equipment	13.14%	7.13%	20.27%	6.15%	3.39%	9.54%
316.00 Miscellaneous Power Plant Equipment	12.19%	6.50%	18.69%	5.82%	3.28%	9.10%
Total Sundt Unit 1	11.26%	5.81%	17.07%	5.04%	2.72%	7.76%
Sundt Unit 2						
310.00 Rights-of-Way						
311.00 Structures and Improvements	8.40%	5.33%	13.73%	5.00%	3.05%	8.05%
312.00 Boiler Plant Equipment	8.25%	5.37%	13.62%	4.08%	2.62%	6.70%
314.00 Turbogenerator Units	8.22%	5.19%	13.41%	3.91%	2.44%	6.35%
315.00 Accessory Electric Equipment	10.07%	6.35%	16.42%	5.61%	3.58%	9.19%
316.00 Miscellaneous Power Plant Equipment	9.57%	5.95%	15.52%	5.36%	3.37%	8.73%
Total Sundt Unit 2	8.62%	5.51%	14.13%	4.43%	2.80%	7.23%
Sundt Unit 3						
310.00 Rights-of-Way						
311.00 Structures and Improvements	6.64%	4.90%	11.54%	4.13%	2.90%	7.03%
312.00 Boiler Plant Equipment	6.17%	4.67%	10.84%	3.88%	2.80%	6.68%
314.00 Turbogenerator Units	6.82%	5.09%	11.91%	4.05%	2.86%	6.91%
315.00 Accessory Electric Equipment	7.15%	5.16%	12.31%	3.98%	2.76%	6.74%
316.00 Miscellaneous Power Plant Equipment	7.90%	5.55%	13.45%	4.62%	3.17%	7.79%
Total Sundt Unit 3	6.66%	4.95%	11.61%	3.99%	2.83%	6.82%
Sundt Unit 4						
310.00 Rights-of-Way						
311.00 Structures and Improvements	1.47%	0.36%	1.83%	2.13%	0.69%	2.82%
312.00 Boiler Plant Equipment	1.47%	0.35%	1.82%	2.09%	0.65%	2.74%
314.00 Turbogenerator Units	1.73%	0.43%	2.16%	2.54%	0.76%	3.30%
315.00 Accessory Electric Equipment	1.53%	0.36%	1.89%	2.32%	0.73%	3.05%
316.00 Miscellaneous Power Plant Equipment	1.78%	0.31%	2.09%	2.41%	0.68%	3.09%
Total Sundt Unit 4	1.52%	0.36%	1.88%	2.19%	0.69%	2.88%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

	Account Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
	A	B	C	D=B+C	E	F	G=E+F
Sundt Solar Booster (Areva)							
310.00	Rights-of-Way						
311.00	Structures and Improvements	3.34%		3.34%			
312.00	Boiler Plant Equipment	3.34%		3.34%	3.11%	0.01%	3.12%
314.00	Turbogenerator Units						
315.00	Accessory Electric Equipment						
316.00	Miscellaneous Power Plant Equipment						
	Total Sundt Solar Booster (Areva)	3.34%		3.34%	3.11%	0.01%	3.12%
OTHER PRODUCTION (by Unit)							
DeMoss Petrie Gas Unit 1							
341.00	Structures and Improvements	2.46%	0.19%	2.65%	2.64%	0.18%	2.82%
342.00	Fuel Holders, Products and Accessories	2.30%	0.21%	2.51%	2.23%	0.20%	2.43%
343.00	Prime Movers	2.90%	0.27%	3.17%	2.86%	0.01%	2.87%
344.00	Generators and Devices	2.30%	0.21%	2.51%	2.24%	0.19%	2.43%
345.00	Accessory Electric Equipment	2.30%	0.21%	2.51%	2.29%	0.05%	2.34%
346.00	Miscellaneous Power Plant Equipment	2.38%	0.22%	2.60%	2.36%	0.21%	2.57%
	Total DeMoss Petrie Gas Unit 1	2.31%	0.21%	2.52%	2.25%	0.19%	2.44%
Gila River							
341.00	Structures and Improvements	2.26%		2.26%	2.42%	0.20%	2.62%
342.00	Fuel Holders, Products and Accessories	2.26%		2.26%	2.40%	0.20%	2.60%
343.00	Prime Movers	2.26%		2.26%	2.44%	0.20%	2.64%
344.00	Generators and Devices	2.26%		2.26%	2.37%	0.20%	2.57%
345.00	Accessory Electric Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
346.00	Miscellaneous Power Plant Equipment	2.26%		2.26%	2.41%	0.20%	2.61%
	Total Gila River	2.26%		2.26%	2.42%	0.20%	2.62%
Gila River Unit 3							
341.00	Structures and Improvements	2.26%		2.26%	2.38%	0.20%	2.58%
342.00	Fuel Holders, Products and Accessories	2.26%		2.26%	2.45%	0.20%	2.65%
343.00	Prime Movers	2.26%		2.26%	2.43%	0.20%	2.63%
344.00	Generators and Devices	2.26%		2.26%	2.37%	0.20%	2.57%
345.00	Accessory Electric Equipment	2.26%		2.26%	2.38%	0.20%	2.58%
346.00	Miscellaneous Power Plant Equipment	2.26%		2.26%	2.41%	0.20%	2.61%
	Total Gila River Unit 3	2.26%		2.26%	2.42%	0.20%	2.62%
Gila River Common							
341.00	Structures and Improvements	2.26%		2.26%	2.42%	0.20%	2.62%
342.00	Fuel Holders, Products and Accessories	2.26%		2.26%	2.40%	0.20%	2.60%
343.00	Prime Movers	2.26%		2.26%	2.59%	0.22%	2.81%
344.00	Generators and Devices	2.26%		2.26%			
345.00	Accessory Electric Equipment	2.26%		2.26%	2.41%	0.20%	2.61%
346.00	Miscellaneous Power Plant Equipment	2.26%		2.26%	2.41%	0.20%	2.61%
	Total Gila River Common	2.26%		2.26%	2.45%	0.21%	2.66%
Luna							
341.00	Structures and Improvements	2.63%	0.51%	3.14%	2.78%	0.52%	3.30%
342.00	Fuel Holders, Products and Accessories	2.62%	0.52%	3.14%	2.78%	0.52%	3.30%
343.00	Prime Movers	2.65%	0.51%	3.16%	2.84%	0.51%	3.35%
344.00	Generators and Devices	2.63%	0.50%	3.13%	2.80%	0.49%	3.29%
345.00	Accessory Electric Equipment	2.57%		2.57%	2.86%	0.54%	3.40%
346.00	Miscellaneous Power Plant Equipment	2.62%	0.52%	3.14%	2.78%	0.52%	3.30%
	Total Luna	2.63%	0.51%	3.14%	2.80%	0.51%	3.31%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

	Account Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
	A	B	C	D=B+C	E	F	G=E+F
North Loop Gas							
341.00	Structures and Improvements	3.17%	0.35%	3.52%	1.18%	0.13%	1.31%
342.00	Fuel Holders, Products and Accessories	2.22%	0.13%	2.35%	2.23%	0.13%	2.36%
343.00	Prime Movers	10.88%	1.39%	12.27%	5.74%	0.66%	6.40%
344.00	Generators and Devices	2.21%	0.18%	2.39%	1.49%	0.08%	1.57%
345.00	Accessory Electric Equipment	2.96%	0.30%	3.26%	1.84%	0.17%	2.01%
346.00	Miscellaneous Power Plant Equipment	2.69%	0.29%	2.98%	0.85%	0.07%	0.92%
	Total North Loop Gas	2.85%	0.27%	3.12%	1.77%	0.13%	1.90%
North Loop Gas Unit 1							
341.00	Structures and Improvements	4.39%	0.49%	4.88%	1.44%	0.20%	1.64%
342.00	Fuel Holders, Products and Accessories						
343.00	Prime Movers	9.60%	1.06%	10.66%	3.78%	0.50%	4.28%
344.00	Generators and Devices	2.65%	0.29%	2.94%	0.22%	0.01%	0.23%
345.00	Accessory Electric Equipment	4.10%	0.45%	4.55%	1.51%	0.19%	1.70%
346.00	Miscellaneous Power Plant Equipment	4.26%	0.48%	4.74%	1.19%	0.16%	1.35%
	Total North Loop Gas Unit 1	3.88%	0.43%	4.31%	0.95%	0.12%	1.07%
North Loop Gas Unit 2							
341.00	Structures and Improvements	1.98%	0.31%	2.29%	0.83%	0.15%	0.98%
342.00	Fuel Holders, Products and Accessories						
343.00	Prime Movers	5.30%	0.82%	6.12%	13.27%	0.69%	13.96%
344.00	Generators and Devices	1.85%	0.26%	2.11%	0.70%	0.10%	0.80%
345.00	Accessory Electric Equipment	2.68%	0.39%	3.07%	1.75%	0.28%	2.03%
346.00	Miscellaneous Power Plant Equipment	0.89%	0.13%	1.02%	0.13%	0.02%	0.15%
	Total North Loop Gas Unit 2	2.13%	0.31%	2.44%	1.58%	0.15%	1.73%
North Loop Gas Unit 3							
341.00	Structures and Improvements	2.17%	0.29%	2.46%	0.48%	0.08%	0.56%
342.00	Fuel Holders, Products and Accessories						
343.00	Prime Movers	13.34%	1.78%	15.12%	5.06%	0.76%	5.82%
344.00	Generators and Devices	1.99%	0.22%	2.21%	0.30%		0.30%
345.00	Accessory Electric Equipment	2.85%	0.37%	3.22%	1.44%	0.21%	1.65%
346.00	Miscellaneous Power Plant Equipment	1.09%	0.15%	1.24%	-0.26%	-0.04%	-0.30%
	Total North Loop Gas Unit 3	4.30%	0.54%	4.84%	1.35%	0.18%	1.53%
North Loop Gas Unit 4							
341.00	Structures and Improvements	2.29%	-0.10%	2.19%	2.33%	-0.09%	2.24%
342.00	Fuel Holders, Products and Accessories	2.22%	0.13%	2.35%	2.23%	0.13%	2.36%
343.00	Prime Movers						
344.00	Generators and Devices	2.22%	0.13%	2.35%	2.24%	0.12%	2.36%
345.00	Accessory Electric Equipment	2.27%	0.11%	2.38%	2.32%	0.10%	2.42%
346.00	Miscellaneous Power Plant Equipment	2.22%	0.06%	2.28%	2.23%	0.06%	2.29%
	Total North Loop Gas Unit 4	2.22%	0.13%	2.35%	2.25%	0.11%	2.36%
Solar Units (Generators and Devices)							
344.00	DeMoss Petrie	5.13%		5.13%	3.05%	0.15%	3.20%
344.00	Fort Huachuca	5.13%		5.13%	3.56%	0.18%	3.74%
344.00	HQ Rooftop	5.13%		5.13%	3.50%	0.18%	3.68%
344.00	OH Rooftop	5.13%		5.13%	3.47%	0.17%	3.64%
344.00	OH Test Yard	5.13%		5.13%	3.10%	0.15%	3.25%
344.00	Prairie Fire	5.13%		5.13%	3.50%	0.18%	3.68%
344.00	Springerville Sites 1-3 (Legacy)	5.13%		5.13%	3.05%	0.15%	3.20%
344.00	Springerville Site 4	5.13%		5.13%	3.43%	0.18%	3.61%
344.00	Tucson	5.13%		5.13%	2.60%	0.13%	2.73%
344.00	U of A Tech Park Site 1	5.13%		5.13%	3.43%	0.18%	3.61%
344.00	U of A Tech Park Site 2	5.13%		5.13%	3.47%	0.17%	3.64%
344.00	White Mountain	5.13%		5.13%	3.56%	0.18%	3.74%
	Total Solar Units	5.13%		5.13%	3.44%	0.17%	3.61%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

	Account Description	Current (at 12/31/2014)			Proposed (at 12/31/2014)		
		Investment	Net Salvage	Total	Investment	Net Salvage	Total
	A	B	C	D=B+C	E	F	G=E+F
Sundt Gas							
341.00	Structures and Improvements	0.26%	0.01%	0.27%	-0.13%	-0.01%	-0.14%
342.00	Fuel Holders, Products and Accessories	8.51%	0.15%	8.66%	3.63%	0.09%	3.72%
343.00	Prime Movers	3.64%	0.06%	3.70%	1.79%	0.04%	1.83%
344.00	Generators and Devices	0.16%		0.16%	-0.37%	-0.02%	-0.39%
345.00	Accessory Electric Equipment	1.37%	0.03%	1.40%	0.17%		0.17%
346.00	Miscellaneous Power Plant Equipment				-1.25%	-0.02%	-1.27%
	Total Sundt Gas	0.96%	0.01%	0.97%	0.02%	-0.01%	0.01%
Sundt Gas Unit 1							
341.00	Structures and Improvements	0.10%		0.10%	-0.08%	-0.01%	-0.09%
342.00	Fuel Holders, Products and Accessories	8.42%	0.14%	8.56%	3.66%	0.08%	3.74%
343.00	Prime Movers	3.51%	0.06%	3.57%	1.83%	0.04%	1.87%
344.00	Generators and Devices				-0.39%	-0.02%	-0.41%
345.00	Accessory Electric Equipment	1.06%	0.02%	1.08%	0.13%	-0.01%	0.12%
346.00	Miscellaneous Power Plant Equipment				-1.21%	-0.02%	-1.23%
	Total Sundt Gas Unit 1	0.77%	0.01%	0.78%	-0.01%	-0.01%	-0.02%
Sundt Gas Unit 2							
341.00	Structures and Improvements	0.41%	0.01%	0.42%	-0.18%	-0.01%	-0.19%
342.00	Fuel Holders, Products and Accessories	8.59%	0.16%	8.75%	3.61%	0.08%	3.69%
343.00	Prime Movers	3.77%	0.06%	3.83%	1.76%	0.03%	1.79%
344.00	Generators and Devices	0.32%		0.32%	-0.34%	-0.02%	-0.36%
345.00	Accessory Electric Equipment	1.65%	0.03%	1.68%	0.21%		0.21%
346.00	Miscellaneous Power Plant Equipment				-1.28%	-0.02%	-1.30%
	Total Sundt Gas Unit 2	1.15%	0.02%	1.17%	0.05%	-0.01%	0.04%

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Net Salvage	Total	Proposed 2015 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION								
310.00 Rights-of-Way	$ 5,106,662	$ 154,751	$ 2	$ 154,753	$ 145,417	$ 5	$ 145,422	$ (9,331)
311.00 Structures and Improvements	205,277,689	6,925,225	672,414	7,597,639	6,508,604	1,383,704	7,892,308	294,669
312.00 Boiler Plant Equipment	1,091,953,161	31,609,169	4,124,981	35,734,150	33,091,364	5,676,033	38,767,397	3,033,247
314.00 Turbogenerator Units	303,041,923	9,895,445	2,168,057	12,063,502	9,960,460	1,660,521	11,620,981	(442,521)
315.00 Accessory Electric Equipment	144,581,471	5,383,758	1,355,199	6,738,957	4,437,440	1,015,739	5,453,179	(1,285,778)
316.00 Miscellaneous Power Plant Equipment	25,222,863	842,395	101,717	944,112	746,073	105,099	851,172	(92,940)
Total Steam Production Plant	$ 1,775,183,769	$ 54,810,743	$ 8,422,370	$ 63,233,113	$ 54,889,358	$ 9,841,101	$ 64,730,459	$ 1,497,346
OTHER PRODUCTION								
Non-Solar								
341.00 Structures and Improvements	$ 23,403,461	$ 587,238	$ 72,042	$ 659,280	$ 603,985	$ 88,395	$ 692,380	$ 33,100
342.00 Fuel Holders, Products and Accessories	19,977,187	541,762	62,185	603,947	530,626	75,123	605,749	1,802
343.00 Prime Movers	202,005,134	4,774,207	83,405	4,857,612	5,028,029	448,274	5,476,303	618,691
344.00 Generators and Devices	105,487,225	2,241,822	156,008	2,397,830	2,059,197	189,494	2,248,691	(149,139)
345.00 Accessory Electric Equipment	13,809,819	322,600	10,605	333,205	289,354	23,496	312,850	(20,355)
346.00 Miscellaneous Power Plant Equipment	15,307,160	374,821	41,324	416,145	384,096	53,510	437,606	21,461
Total Non-Solar	$ 379,989,986	$ 8,842,450	$ 425,569	$ 9,268,019	$ 8,895,287	$ 878,292	$ 9,773,579	$ 505,560
Solar								
344.00 Generators and Devices	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)
Total Solar	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)
Total Other Production Plant	$ 550,310,918	$ 17,579,913	$ 425,569	$ 18,005,482	$ 14,752,043	$ 1,173,557	$ 15,925,600	$ (2,079,882)
DISTRIBUTION PLANT								
360.RW Rights-of-Way	$ 7,865,073	$ 112,471	$ -	$ 112,471	$ 110,898	$ -	$ 110,898	$ (1,573)
361.00 Structures and Improvements	11,402,474	196,123		196,123	194,982		194,982	(1,141)
362.00 Station Equipment	157,067,530	2,403,133		2,403,133	2,607,321		2,607,321	204,188
364.00 Poles, Towers and Fixtures	222,006,967	3,862,921		3,862,921	3,685,316		3,685,316	(177,605)
365.00 Overhead Conductors and Devices	175,675,966	2,863,518		2,863,518	2,881,086		2,881,086	17,568
366.00 Underground Conduit	58,725,355	792,792		792,792	798,665		798,665	5,873
367.00 Underground Conductors and Devices	297,183,135	5,557,325		5,557,325	5,289,860		5,289,860	(267,465)
368.OH Line Transformers - Overhead	103,657,922	1,938,403		1,938,403	1,814,014		1,814,014	(124,389)
368.UG Line Transformers - Underground	172,890,932	3,613,420		3,613,420	3,405,951		3,405,951	(207,469)
369.OH Services - Overhead	17,542,236	324,531		324,531	321,023		321,023	(3,508)
369.UG Services - Underground	112,947,714	1,716,805		1,716,805	1,716,805		1,716,805	
370.00 Meters	44,869,823	1,476,217		1,476,217	2,068,499		2,068,499	592,282
373.00 Street Lighting and Signal Systems	11,778,362	208,477		208,477	207,299		207,299	(1,178)
Total Distribution Plant	$ 1,393,613,489	$ 25,066,136	$ -	$ 25,066,136	$ 25,101,719	$ -	$ 25,101,719	$ 35,583

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Net Salvage	Total	Proposed 2015 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$ 135,680,348	$ 3,378,441	$ 203,521	$ 3,581,962	$ 3,432,713	$ 203,521	$ 3,636,234	$ 54,272
392.C0 Transportation - Class 0	1,238,946	61,452	(9,044)	52,408	63,682	(10,655)	53,027	619
392.C1 Transportation - Class 1	7,718,183	959,370	(139,699)	819,671	1,001,048	(169,800)	831,248	11,577
392.C2 Transportation - Class 2	3,839,907	470,389	(68,350)	402,039	494,580	(85,630)	408,950	6,911
392.C3 Transportation - Class 3	2,076,936	222,440	(32,400)	190,040	238,640	(41,954)	196,686	6,646
392.C4 Transportation - Class 4	2,935,027	206,332	(29,937)	176,395	222,769	(39,623)	183,146	6,751
392.C5 Transportation - Class 5	7,982,715	583,536	(86,213)	497,323	628,240	(104,574)	523,666	26,343
392.C6 Transportation - Class 6	365,200	24,286	(3,652)	20,634	24,761	(3,689)	21,072	438
392.C7 Transportation - Class 7	1,047,216	73,096	(10,891)	62,205	75,400	(11,310)	64,090	1,885
392.C8 Transportation - Class 8	9,957,500	746,813	(112,520)	634,293	781,664	(118,494)	663,170	28,877
392.C9 Transportation - Class 9	4,252,286	198,157	(29,766)	168,391	170,942	(25,939)	145,003	(23,388)
396.00 Power Operatied Equipment	11,860,940	768,589	(28,466)	740,123	797,055	(7,117)	789,938	49,815
397.EM EMS and SCADA Equipment	11,304,371	560,697		560,697	578,784		578,784	18,087
Total Depreciable	$ 200,259,575	$ 8,253,598	$ (347,417)	$ 7,906,181	$ 8,510,278	$ (415,264)	$ 8,095,014	$ 188,833
Amortizable								
391.00 Furniture and Office Equipment	$ 23,964,411	$ 993,514	$ -	$ 993,514	$ 993,514	$ -	$ 993,514	$ -
391.20 Network and Data Equipment	29,359,636	5,484,102		5,484,102	5,484,102		5,484,102	
393.00 Stores Equipment	1,852,479	117,635		117,635	117,635		117,635	
394.00 Tools, Shop and Garage Equipment	6,934,368	396,576		396,576	396,576		396,576	
395.00 Laboratory Equipment	5,091,270	294,185		294,185	294,185		294,185	
397.20 Telecommunications Equipment	57,456,141	3,785,287		3,785,287	3,785,287		3,785,287	
398.00 Miscellaneous Equipment	4,348,209	217,244		217,244	217,244		217,244	
Total Amortizable	$ 129,006,514	$ 11,288,543	$ -	$ 11,288,543	$ 11,288,543	$ -	$ 11,288,543	$ -
Total General Plant	$ 329,266,089	$ 19,542,141	$ (347,417)	$ 19,194,724	$ 19,798,821	$ (415,264)	$ 19,383,557	$ 188,833
SUBTOTAL	$ 4,048,374,265	$ 116,998,933	$ 8,500,522	$ 125,499,455	$ 114,541,941	$ 10,599,394	$ 125,141,335	$ (358,120)
NET SALVAGE								
108.02 Distribution	$ 1,393,613,489	$ -	$ 3,762,756	$ 3,762,756	$ -	$ 3,484,034	$ 3,484,034	$ (278,722)
Total Net Salvage	$ 1,393,613,489	$ -	$ 3,762,756	$ 3,762,756	$ -	$ 3,484,034	$ 3,484,034	$ (278,722)
TOTAL UTILITY	$ 4,048,374,265	$ 116,998,933	$ 12,263,278	$ 129,262,211	$ 114,541,941	$ 14,083,428	$ 128,625,369	$ (636,842)
STEAM PRODUCTION (by Unit)								
Four Corners								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	2,982,777	65,429	5,210	70,639	73,741	4,461	78,202	7,563
312.00 Boiler Plant Equipment	76,402,061	1,219,616	111,205	1,330,821	1,202,927	92,246	1,295,173	(35,648)
314.00 Turbogenerator Units	12,359,480	287,585	16,903	304,488	254,487	12,677	267,164	(37,324)
315.00 Accessory Electric Equipment	4,390,980	153,002	8,523	161,525	177,401	8,702	186,103	24,578
316.00 Miscellaneous Power Plant Equipment	3,832,234	91,767	6,700	98,467	88,687	4,786	93,473	(4,994)
Total Four Corners	$ 99,967,532	$ 1,817,399	$ 148,541	$ 1,965,940	$ 1,797,243	$ 122,872	$ 1,920,115	$ (45,825)

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Current 2015 Annualized Accrual Net Salvage	Current 2015 Annualized Accrual Total	Proposed 2015 Annualized Accrual Investment	Proposed 2015 Annualized Accrual Net Salvage	Proposed 2015 Annualized Accrual Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Four Corners Unit 4								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	1,524,414	32,470	2,439	34,909	35,824	1,982	37,806	2,897
312.00 Boiler Plant Equipment	39,609,538	594,143	63,375	657,518	566,416	55,453	621,869	(35,649)
314.00 Turbogenerator Units	7,179,362	175,176	8,615	183,791	149,331	6,461	155,792	(27,999)
315.00 Accessory Electric Equipment	2,274,836	88,036	3,867	91,903	88,946	3,412	92,358	455
316.00 Miscellaneous Power Plant Equipment	1,929,161	45,142	2,894	48,036	42,442	2,122	44,564	(3,472)
Total Four Corners Unit 4	$ 52,517,311	$ 934,967	$ 81,190	$ 1,016,157	$ 882,959	$ 69,430	$ 952,389	$ (63,768)
Four Corners Unit 5								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	1,458,363	32,959	2,771	35,730	37,917	2,479	40,396	4,666
312.00 Boiler Plant Equipment	36,792,523	625,473	47,830	673,303	636,511	36,793	673,304	1
314.00 Turbogenerator Units	5,180,118	112,409	8,288	120,697	105,156	6,216	111,372	(9,325)
315.00 Accessory Electric Equipment	2,116,144	64,966	4,656	69,622	88,455	5,290	93,745	24,123
316.00 Miscellaneous Power Plant Equipment	1,903,073	46,625	3,806	50,431	46,245	2,664	48,909	(1,522)
Total Four Corners Unit 5	$ 47,450,221	$ 882,432	$ 67,351	$ 949,783	$ 914,284	$ 53,442	$ 967,726	$ 17,943
Navajo								
310.00 Rights-of-Way	$ 12,229	$ 35	$ 2	$ 37	$ 94	$ 5	$ 99	$ 62
311.00 Structures and Improvements	18,655,156	266,935	19,407	286,342	479,050	27,179	506,229	219,887
312.00 Boiler Plant Equipment	88,544,201	1,470,251	90,473	1,560,724	2,789,739	144,143	2,933,882	1,373,158
314.00 Turbogenerator Units	20,255,526	305,780	19,622	325,402	642,358	32,069	674,427	349,025
315.00 Accessory Electric Equipment	14,829,858	277,041	19,470	296,511	576,222	31,388	607,610	311,099
316.00 Miscellaneous Power Plant Equipment	4,518,597	71,350	4,862	76,212	128,777	7,365	136,142	59,930
Total Navajo	$ 146,815,567	$ 2,391,392	$ 153,836	$ 2,545,228	$ 4,616,240	$ 242,149	$ 4,858,389	$ 2,313,161
Navajo Unit 1								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	3,190,563	22,015	1,595	23,610	131,770	6,381	138,151	114,541
312.00 Boiler Plant Equipment	27,198,582	475,975	32,638	508,613	1,631,915	81,596	1,713,511	1,204,898
314.00 Turbogenerator Units	6,860,989	108,404	6,175	114,579	414,404	19,211	433,615	319,036
315.00 Accessory Electric Equipment	3,544,300	53,519	3,190	56,709	300,557	14,177	314,734	258,025
316.00 Miscellaneous Power Plant Equipment	471,227	3,157	236	3,393	18,896	895	19,791	16,398
Total Navajo Unit 1	$ 41,265,661	$ 663,070	$ 43,834	$ 706,904	$ 2,497,542	$ 122,260	$ 2,619,802	$ 1,912,898
Navajo Unit 2								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	1,802,685	17,847	1,262	19,109	25,598	1,622	27,220	8,111
312.00 Boiler Plant Equipment	26,882,286	408,611	24,194	432,805	456,999	26,882	483,881	51,076
314.00 Turbogenerator Units	6,926,050	110,817	8,311	119,128	126,054	8,311	134,365	15,237
315.00 Accessory Electric Equipment	3,172,330	51,392	3,490	54,882	65,033	4,124	69,157	14,275
316.00 Miscellaneous Power Plant Equipment	515,874	4,540	310	4,850	5,004	310	5,314	464
Total Navajo Unit 2	$ 39,299,225	$ 593,207	$ 37,567	$ 630,774	$ 678,688	$ 41,249	$ 719,937	$ 89,163

TUCSON ELECTRIC POWER COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Navajo Unit 3								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	3,681,511	36,447	2,577	39,024	41,233	2,209	43,442	4,418
312.00 Boiler Plant Equipment	27,718,514	437,953	22,175	460,128	507,249	22,175	529,424	69,296
314.00 Turbogenerator Units	6,178,944	75,383	4,325	79,708	87,741	3,707	91,448	11,740
315.00 Accessory Electric Equipment	5,139,872	68,360	5,654	74,014	80,696	5,654	86,350	12,336
316.00 Miscellaneous Power Plant Equipment	549,362	4,010	439	4,449	5,274	494	5,768	1,319
Total Navajo Unit 3	$ 43,268,203	$ 622,153	$ 35,170	$ 657,323	$ 722,193	$ 34,239	$ 756,432	$ 99,109
Navajo Common								
310.00 Rights-of-Way	$ 12,229	$ 35	$ 2	$ 37	$ 94	$ 5	$ 99	$ 62
311.00 Structures and Improvements	9,980,397	190,626	13,973	204,599	280,449	16,967	297,416	92,817
312.00 Boiler Plant Equipment	6,744,819	147,712	11,466	159,178	193,576	13,490	207,066	47,888
314.00 Turbogenerator Units	289,543	11,176	811	11,987	14,159	840	14,999	3,012
315.00 Accessory Electric Equipment	2,973,356	103,770	7,136	110,906	129,936	7,433	137,369	26,463
316.00 Miscellaneous Power Plant Equipment	2,982,134	59,643	3,877	63,520	99,603	5,666	105,269	41,749
Total Navajo Common	$ 22,982,478	$ 512,962	$ 37,265	$ 550,227	$ 717,817	$ 44,401	$ 762,218	$ 211,991
San Juan								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	14,437,744	248,228	21,674	269,902	1,093,818	104,193	1,198,011	928,109
312.00 Boiler Plant Equipment	154,506,908	3,788,408	1,148,165	4,936,573	11,797,736	1,386,578	13,184,314	8,247,741
314.00 Turbogenerator Units	44,295,673	912,491	79,732	992,223	3,357,612	323,358	3,680,970	2,688,747
315.00 Accessory Electric Equipment	10,063,526	210,328	19,121	229,449	767,847	73,464	841,311	611,862
316.00 Miscellaneous Power Plant Equipment	2,009,555	31,839	2,411	34,250	152,968	14,113	167,081	132,831
Total San Juan	$ 225,313,406	$ 5,191,294	$ 1,271,103	$ 6,462,397	$ 17,169,981	$ 1,901,706	$ 19,071,687	$ 12,609,290
San Juan Unit 1								
310.00 Rights-of-Way	$ -	$ -	$ -		$ -	$ -	$ -	$ -
311.00 Structures and Improvements	14,268,404	245,417	21,403	266,820	1,080,118	104,159	1,184,277	917,457
312.00 Boiler Plant Equipment	146,453,029	3,485,582	366,133	3,851,715	11,174,366	1,083,752	12,258,118	8,406,403
314.00 Turbogenerator Units	44,295,673	912,491	79,732	992,223	3,357,612	323,358	3,680,970	2,688,747
315.00 Accessory Electric Equipment	10,063,526	210,328	19,121	229,449	767,847	73,464	841,311	611,862
316.00 Miscellaneous Power Plant Equipment	1,960,172	31,167	2,352	33,519	148,973	14,113	163,086	129,567
Total San Juan Unit 1	$ 217,040,804	$ 4,884,985	$ 488,741	$ 5,373,726	$ 16,528,916	$ 1,598,846	$ 18,127,762	$ 12,754,036
San Juan Common								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	169,340	2,811	271	3,082	13,700	34	13,734	10,652
312.00 Boiler Plant Equipment	8,053,879	302,826	782,032	1,084,858	623,370	302,826	926,196	(158,662)
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment								
316.00 Miscellaneous Power Plant Equipment	49,383	672	59	731	3,995		3,995	3,264
Total San Juan Common	$ 8,272,602	$ 306,309	$ 782,362	$ 1,088,671	$ 641,065	$ 302,860	$ 943,925	$ (144,746)

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Net Salvage	Total	Proposed 2015 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Springerville								
310.00 Rights-of-Way	$ 5,094,433	$ 154,716	$ -	$ 154,716	$ 145,323	$ -	$ 145,323	$ (9,393)
311.00 Structures and Improvements	141,726,641	5,270,099	65,329	5,335,428	4,028,521	849,209	4,877,730	(457,698)
312.00 Boiler Plant Equipment	641,687,365	20,250,799	469,997	20,720,796	13,625,822	2,489,675	16,115,497	(4,605,299)
314.00 Turbogenerator Units	173,649,915	5,159,622	146,103	5,305,725	3,783,448	240,492	4,023,940	(1,281,785)
315.00 Accessory Electric Equipment	75,864,618	2,506,161	57,172	2,563,333	1,444,701	138,955	1,583,656	(979,677)
316.00 Miscellaneous Power Plant Equipment	12,528,984	500,165	7,287	507,452	282,408	29,809	312,217	(195,235)
Total Springerville	$ 1,050,551,956	$ 33,841,562	$ 745,888	$ 34,587,450	$ 23,310,223	$ 3,748,140	$ 27,058,363	$ (7,529,087)
Springerville Unit 1								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	20,076,015	1,600,058	2,008	1,602,066	413,566	16,061	429,627	(1,172,439)
312.00 Boiler Plant Equipment	185,682,490	11,419,473	55,705	11,475,178	3,676,513	148,546	3,825,059	(7,650,119)
314.00 Turbogenerator Units	49,547,312	2,858,880	(24,774)	2,834,106	976,082	39,638	1,015,720	(1,818,386)
315.00 Accessory Electric Equipment	21,214,167	1,289,821	2,121	1,291,942	367,005	16,971	383,976	(907,966)
316.00 Miscellaneous Power Plant Equipment	3,277,742	284,836		284,836	70,144	2,294	72,438	(212,398)
Total Springerville Unit 1	$ 279,797,726	$ 17,453,068	$ 35,060	$ 17,488,128	$ 5,503,310	$ 223,510	$ 5,726,820	$ (11,761,308)
Springerville Unit 1 Common								
310.00 Rights-of-Way	$ 1,143,496	$ -	$ -	$ -	$ 23,213	$ -	$ 23,213	$ 23,213
311.00 Structures and Improvements	52,492,826	1,574,785	5,249	1,580,034	1,070,854	125,983	1,196,837	(383,197)
312.00 Boiler Plant Equipment	14,854,799	629,843		629,843	297,096	38,622	335,718	(294,125)
314.00 Turbogenerator Units	1,264,322	23,137		23,137	24,401	3,287	27,688	4,551
315.00 Accessory Electric Equipment	9,627,097	418,779		418,779	174,250	28,881	203,131	(215,648)
316.00 Miscellaneous Power Plant Equipment	1,959,012	72,875		72,875	35,850	5,485	41,335	(31,540)
Total Springerville Unit 1 Common	$ 81,341,552	$ 2,719,419	$ 5,249	$ 2,724,668	$ 1,625,664	$ 202,258	$ 1,827,922	$ (896,746)
Springerville Unit 2								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	36,540,030	679,645	54,810	734,455	789,265	54,810	844,075	109,620
312.00 Boiler Plant Equipment	295,922,545	5,563,344	414,292	5,977,636	6,273,558	443,884	6,717,442	739,806
314.00 Turbogenerator Units	122,055,348	2,245,818	170,877	2,416,695	2,746,245	183,083	2,929,328	512,633
315.00 Accessory Electric Equipment	42,346,939	715,663	55,051	770,714	796,122	50,816	846,938	76,224
316.00 Miscellaneous Power Plant Equipment	6,624,669	113,282	7,287	120,569	141,768	8,612	150,380	29,811
Total Springerville Unit 2	$ 503,489,531	$ 9,317,752	$ 702,317	$ 10,020,069	$ 10,746,958	$ 741,205	$ 11,488,163	$ 1,468,094
Springerville Unit 2 Common (Leasehold Imp.)								
310.00 Rights-of-Way	$ 2,280,838	$ 63,863	$ -	$ 63,863	$ 88,040	$ -	$ 88,040	$ 24,177
311.00 Structures and Improvements	32,617,770	1,415,611	3,262	1,418,873	1,754,836	652,355	2,407,191	988,318
312.00 Boiler Plant Equipment	6,282,729	345,550		345,550	405,236	135,707	540,943	195,393
314.00 Turbogenerator Units	782,933	31,787		31,787	36,720	14,484	51,204	19,417
315.00 Accessory Electric Equipment	2,676,415	81,898		81,898	107,324	42,287	149,611	67,713
316.00 Miscellaneous Power Plant Equipment	667,561	29,172		29,172	34,646	13,418	48,064	18,892
Total Springerville Unit 2 Common	$ 45,308,246	$ 1,967,881	$ 3,262	$ 1,971,143	$ 2,426,802	$ 858,251	$ 3,285,053	$ 1,313,910

TUCSON ELECTRIC POWER COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Current 2015 Annualized Accrual Net Salvage	Current 2015 Annualized Accrual Total	Proposed 2015 Annualized Accrual Investment	Proposed 2015 Annualized Accrual Net Salvage	Proposed 2015 Annualized Accrual Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Springerville Coal Handling								
310.00 Rights-of-Way	$ 1,670,099	$ 90,853	$ -	$ 90,853	$ 34,070	$ -	$ 34,070	$ (56,783)
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment	138,944,802	2,292,589		2,292,589	2,973,419	1,722,916	4,696,335	2,403,746
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment								
316.00 Miscellaneous Power Plant Equipment								
Total Springerville Coal Handling	$ 140,614,901	$ 2,383,442	$ -	$ 2,383,442	$ 3,007,489	$ 1,722,916	$ 4,730,405	$ 2,346,963
Sundt								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	27,475,371	1,074,534	560,794	1,635,328	833,474	398,662	1,232,136	(403,192)
312.00 Boiler Plant Equipment	130,812,626	4,880,095	2,305,141	7,185,236	3,675,140	1,563,391	5,238,531	(1,946,705)
314.00 Turbogenerator Units	52,481,329	3,229,967	1,905,697	5,135,664	1,922,555	1,051,925	2,974,480	(2,161,184)
315.00 Accessory Electric Equipment	39,432,489	2,237,226	1,250,913	3,488,139	1,471,269	763,230	2,234,499	(1,253,640)
316.00 Miscellaneous Power Plant Equipment	2,333,493	147,274	80,457	227,731	93,233	49,026	142,259	(85,472)
Total Sundt	$ 252,535,308	$ 11,569,096	$ 6,103,002	$ 17,672,098	$ 7,995,671	$ 3,826,234	$ 11,821,905	$ (5,850,193)
Sundt Unit 1								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	3,926,062	390,643	210,830	601,473	195,910	108,752	304,662	(296,811)
312.00 Boiler Plant Equipment	13,782,181	1,433,347	691,865	2,125,212	625,711	326,638	952,349	(1,172,863)
314.00 Turbogenerator Units	10,237,507	1,195,741	630,630	1,826,371	509,828	277,436	787,264	(1,039,107)
315.00 Accessory Electric Equipment	6,536,315	858,872	466,039	1,324,911	401,983	221,581	623,564	(701,347)
316.00 Miscellaneous Power Plant Equipment	490,578	59,801	31,888	91,689	28,552	16,091	44,643	(47,046)
Total Sundt Unit 1	$ 34,972,643	$ 3,938,404	$ 2,031,252	$ 5,969,656	$ 1,761,984	$ 950,498	$ 2,712,482	$ (3,257,174)
Sundt Unit 2								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	2,812,689	236,266	149,916	386,182	140,634	85,787	226,421	(159,761)
312.00 Boiler Plant Equipment	14,371,609	1,185,658	771,755	1,957,413	586,362	376,536	962,898	(994,515)
314.00 Turbogenerator Units	8,451,923	694,748	438,655	1,133,403	330,470	206,227	536,697	(596,706)
315.00 Accessory Electric Equipment	6,205,700	624,914	394,062	1,018,976	348,140	222,164	570,304	(448,672)
316.00 Miscellaneous Power Plant Equipment	383,824	36,732	22,838	59,570	20,573	12,935	33,508	(26,062)
Total Sundt Unit 2	$ 32,225,745	$ 2,778,318	$ 1,777,226	$ 4,555,544	$ 1,426,179	$ 903,649	$ 2,329,828	$ (2,225,716)
Sundt Unit 3								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	2,762,012	183,398	135,339	318,737	114,071	80,098	194,169	(124,568)
312.00 Boiler Plant Equipment	11,980,831	739,217	559,505	1,298,722	464,856	335,463	800,319	(498,403)
314.00 Turbogenerator Units	14,830,615	1,011,448	754,878	1,766,326	600,640	424,156	1,024,796	(741,530)
315.00 Accessory Electric Equipment	6,140,139	439,020	316,831	755,851	244,378	169,468	413,846	(342,005)
316.00 Miscellaneous Power Plant Equipment	404,717	31,973	22,462	54,435	18,698	12,830	31,528	(22,907)
Total Sundt Unit 3	$ 36,118,314	$ 2,405,056	$ 1,789,015	$ 4,194,071	$ 1,442,643	$ 1,022,015	$ 2,464,658	$ (1,729,413)

TUCSON ELECTRIC POWER COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Net Salvage	Total	Proposed 2015 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Sundt Unit 4								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	17,974,608	264,227	64,709	328,936	382,859	124,025	506,884	177,948
312.00 Boiler Plant Equipment	80,576,055	1,184,468	282,016	1,466,484	1,684,040	523,744	2,207,784	741,300
314.00 Turbogenerator Units	18,961,284	328,030	81,534	409,564	481,617	144,106	625,723	216,159
315.00 Accessory Electric Equipment	20,550,335	314,420	73,981	388,401	476,768	150,017	626,785	238,384
316.00 Miscellaneous Power Plant Equipment	1,054,374	18,768	3,269	22,037	25,410	7,170	32,580	10,543
Total Sundt Unit 4	$ 139,116,656	$ 2,109,913	$ 505,509	$ 2,615,422	$ 3,050,694	$ 949,062	$ 3,999,756	$ 1,384,334
Sundt Solar Booster (Areva)								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment	10,101,950	337,405		337,405	314,171	1,010	315,181	(22,224)
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment								
316.00 Miscellaneous Power Plant Equipment								
Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 337,405	$ -	$ 337,405	$ 314,171	$ 1,010	$ 315,181	$ (22,224)
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00 Structures and Improvements	$ 761,988	$ 18,745	$ 1,448	$ 20,193	$ 20,116	$ 1,372	$ 21,488	$ 1,295
342.00 Fuel Holders, Products and Accessories	750,386	17,259	1,576	18,835	16,734	1,501	18,235	(600)
343.00 Prime Movers	76,766	2,226	207	2,433	2,196	8	2,204	(229)
344.00 Generators and Devices	30,772,866	707,776	64,623	772,399	689,312	58,468	747,780	(24,619)
345.00 Accessory Electric Equipment	861,492	19,814	1,809	21,623	19,728	431	20,159	(1,464)
346.00 Miscellaneous Power Plant Equipment	376,605	8,963	829	9,792	8,888	791	9,679	(113)
Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 774,783	$ 70,492	$ 845,275	$ 756,974	$ 62,571	$ 819,545	$ (25,730)
Gila River								
341.00 Structures and Improvements	$ 8,508,950	$ 192,303	$ -	$ 192,303	$ 205,534	$ 17,018	$ 222,552	$ 30,249
342.00 Fuel Holders, Products and Accessories	6,783,045	153,296		153,296	162,882	13,566	176,448	23,152
343.00 Prime Movers	188,744,730	4,265,631		4,265,631	4,597,974	378,924	4,976,898	711,267
344.00 Generators and Devices	32,783,434	740,906		740,906	776,967	65,567	842,534	101,628
345.00 Accessory Electric Equipment	9,030,698	204,094		204,094	215,581	18,061	233,642	29,548
346.00 Miscellaneous Power Plant Equipment	6,799,960	153,679		153,679	163,879	13,600	177,479	23,800
Total Gila River	$ 252,650,817	$ 5,709,909	$ -	$ 5,709,909	$ 6,122,817	$ 506,736	$ 6,629,553	$ 919,644

TUCSON ELECTRIC POWER COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Net Salvage	Total	Proposed 2015 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Gila River Unit 3								
341.00 Structures and Improvements	$ 957,417	$ 21,638	$ -	$ 21,638	$ 22,787	$ 1,915	$ 24,702	$ 3,064
342.00 Fuel Holders, Products and Accessories	178,424	4,032		4,032	4,371	357	4,728	696
343.00 Prime Movers	181,571,712	4,103,521		4,103,521	4,412,193	363,143	4,775,336	671,815
344.00 Generators and Devices	32,783,434	740,906		740,906	776,967	65,567	842,534	101,628
345.00 Accessory Electric Equipment	6,860,554	155,049		155,049	163,281	13,721	177,002	21,953
346.00 Miscellaneous Power Plant Equipment	135,558	3,064		3,064	3,267	271	3,538	474
Total Gila River Unit 3	$ 222,487,099	$ 5,028,210	$ -	$ 5,028,210	$ 5,382,866	$ 444,974	$ 5,827,840	$ 799,630
Gila River Common								
341.00 Structures and Improvements	$ 7,551,533	$ 170,665	$ -	$ 170,665	$ 182,747	$ 15,103	$ 197,850	$ 27,185
342.00 Fuel Holders, Products and Accessories	6,604,621	149,264		149,264	158,511	13,209	171,720	22,456
343.00 Prime Movers	7,173,018	162,110		162,110	185,781	15,781	201,562	39,452
344.00 Generators and Devices								
345.00 Accessory Electric Equipment	2,170,144	49,045		49,045	52,300	4,340	56,640	7,595
346.00 Miscellaneous Power Plant Equipment	6,664,402	150,615		150,615	160,612	13,329	173,941	23,326
Total Gila River Common	$ 30,163,718	$ 681,699	$ -	$ 681,699	$ 739,951	$ 61,762	$ 801,713	$ 120,014
Luna								
341.00 Structures and Improvements	$ 13,232,832	$ 348,023	$ 67,487	$ 415,510	$ 367,873	$ 68,811	$ 436,684	$ 21,174
342.00 Fuel Holders, Products and Accessories	11,352,383	297,432	59,032	356,464	315,596	59,032	374,628	18,164
343.00 Prime Movers	11,151,074	295,503	56,870	352,373	316,691	56,870	373,561	21,188
344.00 Generators and Devices	9,486,694	249,500	47,433	296,933	265,627	46,485	312,112	15,179
345.00 Accessory Electric Equipment	9,647	248		248	276	52	328	80
346.00 Miscellaneous Power Plant Equipment	7,424,592	194,524	38,608	233,132	206,404	38,608	245,012	11,880
Total Luna	$ 52,657,222	$ 1,385,230	$ 269,430	$ 1,654,660	$ 1,472,467	$ 269,858	$ 1,742,325	$ 87,665
North Loop Gas								
341.00 Structures and Improvements	$ 888,601	$ 28,138	$ 3,106	$ 31,244	$ 10,476	$ 1,196	$ 11,672	$ (19,572)
342.00 Fuel Holders, Products and Accessories	303,037	6,727	394	7,121	6,758	394	7,152	31
343.00 Prime Movers	1,890,946	205,693	26,244	231,937	108,626	12,423	121,049	(110,888)
344.00 Generators and Devices	24,062,187	530,628	43,952	574,580	357,948	20,650	378,598	(195,982)
345.00 Accessory Electric Equipment	2,829,171	83,689	8,524	92,213	51,917	5,004	56,921	(35,292)
346.00 Miscellaneous Power Plant Equipment	656,253	17,655	1,887	19,542	5,548	521	6,069	(13,473)
Total North Loop Gas	$ 30,630,195	$ 872,530	$ 84,107	$ 956,637	$ 541,273	$ 40,188	$ 581,461	$ (375,176)
North Loop Gas Unit 1								
341.00 Structures and Improvements	$ 411,070	$ 18,046	$ 2,014	$ 20,060	$ 5,919	$ 822	$ 6,741	$ (13,319)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	678,545	65,140	7,193	72,333	25,649	3,393	29,042	(43,291)
344.00 Generators and Devices	3,582,271	94,930	10,389	105,319	7,881	358	8,239	(97,080)
345.00 Accessory Electric Equipment	790,955	32,429	3,559	35,988	11,943	1,503	13,446	(22,542)
346.00 Miscellaneous Power Plant Equipment	306,369	13,051	1,471	14,522	3,646	490	4,136	(10,386)
Total North Loop Gas Unit 1	$ 5,769,210	$ 223,596	$ 24,626	$ 248,222	$ 55,038	$ 6,566	$ 61,604	$ (186,618)

TUCSON ELECTRIC POWER COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Net Salvage	Total	Proposed 2015 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
North Loop Gas Unit 2								
341.00 Structures and Improvements	$ 196,078	$ 3,882	$ 608	$ 4,490	$ 1,627	$ 294	$ 1,921	$ (2,569)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	263,450	13,963	2,160	16,123	34,960	1,818	36,778	20,655
344.00 Generators and Devices	3,239,719	59,935	8,423	68,358	22,678	3,240	25,918	(42,440)
345.00 Accessory Electric Equipment	504,895	13,531	1,969	15,500	8,836	1,414	10,250	(5,250)
346.00 Miscellaneous Power Plant Equipment	128,559	1,144	167	1,311	167	26	193	(1,118)
Total North Loop Gas Unit 2	$ 4,332,701	$ 92,455	$ 13,327	$ 105,782	$ 68,268	$ 6,792	$ 75,060	$ (30,722)
North Loop Gas Unit 3								
341.00 Structures and Improvements	$ 196,078	$ 4,255	$ 569	$ 4,824	$ 941	$ 157	$ 1,098	$ (3,726)
342.00 Fuel Holders, Products and Accessories								
343.00 Prime Movers	948,951	126,590	16,891	143,481	48,017	7,212	55,229	(88,252)
344.00 Generators and Devices	3,030,531	60,308	6,667	66,975	9,092		9,092	(57,883)
345.00 Accessory Electric Equipment	503,907	14,361	1,864	16,225	7,256	1,058	8,314	(7,911)
346.00 Miscellaneous Power Plant Equipment	128,559	1,401	193	1,594	(334)	(51)	(385)	(1,979)
Total North Loop Gas Unit 3	$ 4,808,026	$ 206,915	$ 26,184	$ 233,099	$ 64,972	$ 8,376	$ 73,348	$ (159,751)
North Loop Gas Unit 4								
341.00 Structures and Improvements	$ 85,375	$ 1,955	$ (85)	$ 1,870	$ 1,989	$ (77)	$ 1,912	$ 42
342.00 Fuel Holders, Products and Accessories	303,037	6,727	394	7,121	6,758	394	7,152	31
343.00 Prime Movers								
344.00 Generators and Devices	14,209,666	315,455	18,473	333,928	318,297	17,052	335,349	1,421
345.00 Accessory Electric Equipment	1,029,414	23,368	1,132	24,500	23,882	1,029	24,911	411
346.00 Miscellaneous Power Plant Equipment	92,766	2,059	56	2,115	2,069	56	2,125	10
Total North Loop Gas Unit 4	$ 15,720,258	$ 349,564	$ 19,970	$ 369,534	$ 352,995	$ 18,454	$ 371,449	$ 1,915
Solar Units (Generators and Devices)								
344.00 DeMoss Petrie	$ 1,146,081	$ 58,794	$ -	$ 58,794	$ 34,955	$ 1,719	$ 36,674	$ (22,120)
344.00 Fort Huachuca	36,709,538	1,883,199		1,883,199	1,306,860	66,077	1,372,937	(510,262)
344.00 HQ Rooftop	303,184	15,553		15,553	10,611	546	11,157	(4,396)
344.00 OH Rooftop	2,594,590	133,102		133,102	90,032	4,411	94,443	(38,659)
344.00 OH Test Yard	388,459	19,928		19,928	12,042	583	12,625	(7,303)
344.00 Prairie Fire	19,036,520	976,573		976,573	666,278	34,266	700,544	(276,029)
344.00 Springerville Sites 1-3 (Legacy)	28,766,605	1,475,727		1,475,727	877,381	43,150	920,531	(555,196)
344.00 Springerville Site 4	7,873,874	403,930		403,930	270,074	14,173	284,247	(119,683)
344.00 Tucson	87,198	4,473		4,473	2,267	113	2,380	(2,093)
344.00 U of A Tech Park Site 1	7,723,832	396,233		396,233	264,927	13,903	278,830	(117,403)
344.00 U of A Tech Park Site 2	19,191,952	984,547		984,547	665,961	32,626	698,587	(285,960)
344.00 White Mountain	46,499,099	2,385,404		2,385,404	1,655,368	83,698	1,739,066	(646,338)
Total Solar Units	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)

TUCSON ELECTRIC POWER COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Sundt Gas								
341.00 Structures and Improvements	$ 11,090	$ 29	$ 1	$ 30	$ (14)	$ (2)	$ (16)	$ (46)
342.00 Fuel Holders, Products and Accessories	788,336	67,048	1,183	68,231	28,656	630	29,286	(38,945)
343.00 Prime Movers	141,618	5,154	84	5,238	2,542	49	2,591	(2,647)
344.00 Generators and Devices	8,382,044	13,012		13,012	(30,657)	(1,676)	(32,333)	(45,345)
345.00 Accessory Electric Equipment	1,078,811	14,755	272	15,027	1,852	(52)	1,800	(13,227)
346.00 Miscellaneous Power Plant Equipment	49,750				(623)	(10)	(633)	(633)
Total Sundt Gas	$ 10,451,649	$ 99,998	$ 1,540	$ 101,538	$ 1,756	$ (1,061)	$ 695	$ (100,843)
Sundt Gas Unit 1								
341.00 Structures and Improvements	$ 5,545	$ 6	$ -	$ 6	$ (4)	$ (1)	$ (5)	$ (11)
342.00 Fuel Holders, Products and Accessories	394,168	33,189	552	33,741	14,427	315	14,742	(18,999)
343.00 Prime Movers	70,809	2,485	42	2,527	1,296	28	1,324	(1,203)
344.00 Generators and Devices	4,315,668				(16,831)	(863)	(17,694)	(17,694)
345.00 Accessory Electric Equipment	516,231	5,472	103	5,575	671	(52)	619	(4,956)
346.00 Miscellaneous Power Plant Equipment	19,906				(241)	(4)	(245)	(245)
Total Sundt Gas Unit 1	$ 5,322,327	$ 41,152	$ 697	$ 41,849	$ (682)	$ (577)	$ (1,259)	$ (43,108)
Sundt Gas Unit 2								
341.00 Structures and Improvements	$ 5,545	$ 23	$ 1	$ 24	$ (10)	$ (1)	$ (11)	$ (35)
342.00 Fuel Holders, Products and Accessories	394,168	33,859	631	34,490	14,229	315	14,544	(19,946)
343.00 Prime Movers	70,809	2,669	42	2,711	1,246	21	1,267	(1,444)
344.00 Generators and Devices	4,066,376	13,012		13,012	(13,826)	(813)	(14,639)	(27,651)
345.00 Accessory Electric Equipment	562,580	9,283	169	9,452	1,181		1,181	(8,271)
346.00 Miscellaneous Power Plant Equipment	29,844				(382)	(6)	(388)	(388)
Total Sundt Gas Unit 2	$ 5,129,322	$ 58,846	$ 843	$ 59,689	$ 2,438	$ (484)	$ 1,954	$ (57,735)

TUCSON ELECTRIC POWER COMPANY
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
310.00 Rights-of-Way	$ 5,106,662	$ 3,694,243	72.34%	$ 2,875,801	56.31%	$ 2,447,153	47.92%
311.00 Structures and Improvements	205,277,689	105,373,653	51.33%	108,874,331	53.04%	97,248,235	47.37%
312.00 Boiler Plant Equipment	1,091,953,161	430,944,377	39.47%	540,470,593	49.50%	446,282,641	40.87%
314.00 Turbogenerator Units	303,041,923	108,786,141	35.90%	133,946,536	44.20%	108,151,958	35.69%
315.00 Accessory Electric Equipment	144,581,471	67,267,210	46.53%	68,934,846	47.68%	62,107,925	42.96%
316.00 Miscellaneous Power Plant Equipment	25,222,863	11,455,994	45.42%	11,404,754	45.22%	11,283,704	44.74%
Total Steam Production Plant	$ 1,775,183,769	$ 727,521,616	40.98%	$ 866,506,861	48.81%	$ 727,521,616	40.98%
OTHER PRODUCTION							
Non-Solar							
341.00 Structures and Improvements	$ 23,403,461	$ 4,517,794	19.30%	$ 5,824,666	24.89%	$ 3,626,965	15.50%
342.00 Fuel Holders, Products and Accessories	19,977,187	3,821,601	19.13%	4,890,928	24.48%	2,958,341	14.81%
343.00 Prime Movers	202,005,134	45,871,980	22.71%	48,215,536	23.87%	45,970,311	22.76%
344.00 Generators and Devices	105,487,225	42,523,497	40.31%	39,253,861	37.21%	44,592,063	42.27%
345.00 Accessory Electric Equipment	13,809,819	5,672,963	41.08%	4,932,963	35.72%	5,718,985	41.41%
346.00 Miscellaneous Power Plant Equipment	15,307,160	3,234,180	21.13%	3,997,542	26.12%	2,775,348	18.13%
Total Non-Solar	$ 379,989,986	$ 105,642,014	27.80%	$ 107,115,497	28.19%	$ 105,642,014	27.80%
Solar							
344.00 Generators and Devices	$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
Total Solar	$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
Total Other Production Plant	$ 550,310,918	$ 132,534,346	24.08%	$ 129,531,575	23.54%	$ 132,534,346	24.08%
DISTRIBUTION PLANT							
360.RW Rights-of-Way	$ 7,865,073	$ 3,685,111	46.85%	$ 2,967,754	37.73%	$ 3,720,941	47.31%
361.00 Structures and Improvements	11,402,474	2,440,911	21.41%	1,927,786	16.91%	2,417,039	21.20%
362.00 Station Equipment	157,067,530	44,816,223	28.53%	38,291,794	24.38%	48,009,871	30.57%
364.00 Poles, Towers and Fixtures	222,006,967	71,565,728	32.24%	53,853,971	24.26%	67,521,575	30.41%
365.00 Overhead Conductors and Devices	175,675,966	59,385,788	33.80%	50,923,833	28.99%	63,847,797	36.34%
366.00 Underground Conduit	58,725,355	23,125,320	39.38%	18,680,394	31.81%	23,421,293	39.88%
367.00 Underground Conductors and Devices	297,183,135	119,413,016	40.18%	92,262,153	31.05%	115,677,372	38.92%
368.OH Line Transformers - Overhead	103,657,922	45,498,501	43.89%	31,691,984	30.57%	39,735,096	38.33%
368.UG Line Transformers - Underground	172,890,932	71,195,629	41.18%	52,540,781	30.39%	65,875,110	38.10%
369.OH Services - Overhead	17,542,236	8,133,240	46.36%	6,372,839	36.33%	7,990,202	45.55%
369.UG Services - Underground	112,947,714	35,019;387	31.00%	28,664,832	25.38%	35,939,682	31.82%
370.00 Meters	44,869,823	(225,711)	-0.50%	8,648,279	19.27%	10,843,126	24.17%
373.00 Street Lighting and Signal Systems	11,778,362	4,929,241	41.85%	3,992,908	33.90%	5,006,268	42.50%
Total Distribution Plant	$ 1,393,613,489	$ 488,982,384	35.09%	$ 390,819,309	28.04%	$ 490,005,372	35.16%

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Account Description		Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G	H=G/B
GENERAL PLANT								
Depreciable								
390.00	Structures and Improvements	$ 135,680,348	$ 22,140,915	16.32%	$ 23,121,989	17.04%	$ 21,696,815	15.99%
392.C0	Transportation - Class 0	1,238,946	537,462	43.38%	430,858	34.78%	404,302	32.63%
392.C1	Transportation - Class 1	7,718,183	3,370,156	43.67%	3,085,389	39.98%	2,895,214	37.51%
392.C2	Transportation - Class 2	3,839,907	1,471,770	38.33%	1,512,999	39.40%	1,419,742	36.97%
392.C3	Transportation - Class 3	2,076,936	1,040,386	50.09%	982,304	47.30%	921,757	44.38%
392.C4	Transportation - Class 4	2,935,027	748,506	25.50%	1,119,503	38.14%	1,050,500	35.79%
392.C5	Transportation - Class 5	7,982,715	2,758,719	34.56%	3,223,932	40.39%	3,025,218	37.90%
392.C6	Transportation - Class 6	365,200	71,788	19.66%	72,748	19.92%	68,264	18.69%
392.C7	Transportation - Class 7	1,047,216	431,484	41.20%	371,401	35.47%	348,508	33.28%
392.C8	Transportation - Class 8	9,957,500	3,320,461	33.35%	3,285,253	32.99%	3,082,759	30.96%
392.C9	Transportation - Class 9	4,252,286	1,578,200	37.11%	1,139,077	26.79%	1,068,867	25.14%
396.00	Power Operatied Equipment	11,860,940	2,437,035	20.55%	2,664,204	22.46%	2,499,990	21.08%
397.EM	EMS and SCADA Equipment	11,304,371	3,197,149	28.28%	3,314,518	29.32%	3,110,221	27.51%
Total Depreciable		$ 200,259,575	$ 43,104,031	21.52%	$ 44,324,175	22.13%	$ 41,592,158	20.77%
Amortizable								
391.00	Furniture and Office Equipment	$ 23,964,411	$ 7,694,941	32.11%	$ 7,698,753	32.13%	$ 7,698,753	32.13%
391.20	Network and Data Equipment	29,359,636	14,970,053	50.99%	14,913,970	50.80%	14,913,970	50.80%
393.00	Stores Equipment	1,852,479	820,258	44.28%	840,197	45.36%	840,197	45.36%
394.00	Tools, Shop and Garage Equipment	6,934,368	2,860,187	41.25%	2,858,589	41.22%	2,858,589	41.22%
395.00	Laboratory Equipment	5,091,270	2,395,517	47.05%	2,395,826	47.06%	2,395,826	47.06%
397.20	Telecommunications Equipment	57,456,141	18,113,523	31.53%	19,662,636	34.22%	19,662,636	34.22%
398.00	Miscellaneous Equipment	4,348,209	1,818,966	41.83%	1,815,347	41.75%	1,815,347	41.75%
Total Amortizable		$ 129,006,514	$ 48,673,445	37.73%	$ 50,185,318	38.90%	$ 50,185,318	38.90%
Total General Plant		$ 329,266,089	$ 91,777,476	27.87%	$ 94,509,493	28.70%	$ 91,777,476	27.87%
SUBTOTAL		$ 4,048,374,265	$ 1,440,815,822	35.59%	$ 1,481,367,238	36.59%	$ 1,441,838,810	35.62%
NET SALVAGE								
108.02	Distribution	$ 1,393,613,489	$ 85,838,400	6.16%	$ 67,647,219	4.85%	$ 84,815,412	6.09%
Total Net Salvage		$ 1,393,613,489	$ 85,838,400	6.16%	$ 67,647,219	4.85%	$ 84,815,412	6.09%
TOTAL UTILITY		$ 4,048,374,265	$ 1,526,654,221	37.71%	$ 1,549,014,457	38.26%	$ 1,526,654,221	37.71%

TUCSON ELECTRIC POWER COMPANY
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Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION (by Unit)							
Four Corners							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	2,982,777	1,813,087	60.79%	1,407,310	47.18%	1,908,245	63.98%
312.00 Boiler Plant Equipment	76,402,061	60,687,020	79.43%	44,493,936	58.24%	60,345,088	78.98%
314.00 Turbogenerator Units	12,359,480	8,806,344	71.25%	6,490,155	52.51%	8,830,514	71.45%
315.00 Accessory Electric Equipment	4,390,980	1,422,016	32.38%	1,224,683	27.89%	1,663,472	37.88%
316.00 Miscellaneous Power Plant Equipment	3,832,234	2,573,936	67.17%	1,885,490	49.20%	2,555,084	66.67%
Total Four Corners	$ 99,967,532	$ 75,302,403	75.33%	$ 55,501,573	55.52%	$ 75,302,403	75.33%
Four Corners Unit 4							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,524,414	957,081	62.78%	717,080	47.04%	1,004,130	65.87%
312.00 Boiler Plant Equipment	39,609,538	32,129,841	81.12%	22,819,676	57.61%	31,954,492	80.67%
314.00 Turbogenerator Units	7,179,362	5,095,340	70.97%	3,640,615	50.71%	5,097,969	71.01%
315.00 Accessory Electric Equipment	2,274,836	782,000	34.38%	655,647	28.82%	918,105	40.36%
316.00 Miscellaneous Power Plant Equipment	1,929,161	1,331,723	69.03%	943,572	48.91%	1,321,288	68.49%
Total Four Corners Unit 4	$ 52,517,311	$ 40,295,985	76.73%	$ 28,776,589	54.79%	$ 40,295,985	76.73%
Four Corners Unit 5							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,458,363	856,006	58.70%	690,230	47.33%	904,116	62.00%
312.00 Boiler Plant Equipment	36,792,523	28,557,180	77.62%	21,674,260	58.91%	28,390,596	77.16%
314.00 Turbogenerator Units	5,180,118	3,711,004	71.64%	2,849,540	55.01%	3,732,544	72.06%
315.00 Accessory Electric Equipment	2,116,144	640,016	30.24%	569,037	26.89%	745,368	35.22%
316.00 Miscellaneous Power Plant Equipment	1,903,073	1,242,213	65.27%	941,918	49.49%	1,233,795	64.83%
Total Four Corners Unit 5	$ 47,450,221	$ 35,006,419	73.78%	$ 26,724,984	56.32%	$ 35,006,419	73.78%
Navajo							
310.00 Rights-of-Way	$ 12,229	$ 12,671	103.62%	$ 9,126	74.62%	$ 11,451	93.64%
311.00 Structures and Improvements	18,655,156	13,989,522	74.99%	11,536,575	61.84%	13,565,143	72.72%
312.00 Boiler Plant Equipment	88,544,201	67,034,406	75.71%	59,294,347	66.97%	67,573,826	76.32%
314.00 Turbogenerator Units	20,255,526	16,002,717	79.00%	14,005,570	69.14%	15,851,652	78.26%
315.00 Accessory Electric Equipment	14,829,858	9,777,819	65.93%	8,446,290	56.95%	9,853,980	66.45%
316.00 Miscellaneous Power Plant Equipment	4,518,597	2,967,546	65.67%	2,438,444	53.96%	2,928,630	64.81%
Total Navajo	$ 146,815,567	$ 109,784,682	74.78%	$ 95,730,352	65.20%	$ 109,784,682	74.78%

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Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Navajo Unit 1							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	3,190,563	3,081,399	96.58%	2,941,499	92.19%	2,732,322	85.64%
312.00 Boiler Plant Equipment	27,198,582	20,390,194	74.97%	22,499,824	82.72%	20,899,807	76.84%
314.00 Turbogenerator Units	6,860,989	5,372,911	78.31%	5,669,140	82.63%	5,265,994	76.75%
315.00 Accessory Electric Equipment	3,544,300	2,315,538	65.33%	2,491,890	70.31%	2,314,686	65.31%
316.00 Miscellaneous Power Plant Equipment	471,227	458,551	97.31%	436,850	92.70%	405,785	86.11%
Total Navajo Unit 1	$ 41,265,661	$ 31,618,592	76.62%	$ 34,039,203	82.49%	$ 31,618,592	76.62%
Navajo Unit 2							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,802,685	1,519,996	84.32%	1,182,807	65.61%	1,509,362	83.73%
312.00 Boiler Plant Equipment	26,882,286	21,334,917	79.36%	16,714,013	62.17%	21,328,503	79.34%
314.00 Turbogenerator Units	6,926,050	5,347,290	77.21%	4,189,462	60.49%	5,346,110	77.19%
315.00 Accessory Electric Equipment	3,172,330	2,305,054	72.66%	1,828,615	57.64%	2,333,469	73.56%
316.00 Miscellaneous Power Plant Equipment	515,874	478,584	92.77%	367,057	71.15%	468,397	90.80%
Total Navajo Unit 2	$ 39,299,225	$ 30,985,841	78.85%	$ 24,281,955	61.79%	$ 30,985,841	78.85%
Navajo Unit 3							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	3,681,511	3,289,429	89.35%	2,564,640	69.66%	3,240,677	88.03%
312.00 Boiler Plant Equipment	27,718,514	21,206,074	76.51%	16,877,474	60.89%	21,326,362	76.94%
314.00 Turbogenerator Units	6,178,944	5,218,613	84.46%	4,083,695	66.09%	5,160,153	83.51%
315.00 Accessory Electric Equipment	5,139,872	4,138,011	80.51%	3,272,439	63.67%	4,135,051	80.45%
316.00 Miscellaneous Power Plant Equipment	549,362	503,918	91.73%	390,790	71.14%	493,802	89.89%
Total Navajo Unit 3	$ 43,268,203	$ 34,356,045	79.40%	$ 27,189,038	62.84%	$ 34,356,045	79.40%
Navajo Common							
310.00 Rights-of-Way	$ 12,229	$ 12,671	103.62%	$ 9,126	74.62%	$ 11,451	93.64%
311.00 Structures and Improvements	9,980,397	6,098,698	61.11%	4,847,630	48.57%	6,082,782	60.95%
312.00 Boiler Plant Equipment	6,744,819	4,103,220	60.84%	3,203,036	47.49%	4,019,154	59.59%
314.00 Turbogenerator Units	289,543	63,903	22.07%	63,273	21.85%	79,395	27.42%
315.00 Accessory Electric Equipment	2,973,356	1,019,217	34.28%	853,346	28.70%	1,070,774	36.01%
316.00 Miscellaneous Power Plant Equipment	2,982,134	1,526,493	51.19%	1,243,747	41.71%	1,560,647	52.33%
Total Navajo Common	$ 22,982,478	$ 12,824,203	55.80%	$ 10,220,157	44.47%	$ 12,824,203	55.80%

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San Juan								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	14,437,744	3,437,723	23.81%	9,119,596	63.16%	1,087,211	7.53%
312.00	Boiler Plant Equipment	154,506,908	6,056,700	3.92%	87,767,581	56.80%	10,463,387	6.77%
314.00	Turbogenerator Units	44,295,673	6,542,378	14.77%	27,834,853	62.84%	3,318,387	7.49%
315.00	Accessory Electric Equipment	10,063,526	(132,385)	-1.32%	5,754,151	57.18%	685,993	6.82%
316.00	Miscellaneous Power Plant Equipment	2,009,555	(208,748)	-10.39%	1,180,121	58.73%	140,690	7.00%
Total San Juan		$ 225,313,406	$ 15,695,668	6.97%	$ 131,656,301	58.43%	$ 15,695,668	6.97%
San Juan Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	14,268,404	3,436,921	24.09%	9,113,095	63.87%	1,086,436	7.61%
312.00	Boiler Plant Equipment	146,453,029	1,499,790	1.02%	82,646,788	56.43%	9,852,901	6.73%
314.00	Turbogenerator Units	44,295,673	6,542,378	14.77%	27,834,853	62.84%	3,318,387	7.49%
315.00	Accessory Electric Equipment	10,063,526	(132,385)	-1.32%	5,754,151	57.18%	685,993	6.82%
316.00	Miscellaneous Power Plant Equipment	1,960,172	(209,009)	-10.66%	1,178,229	60.11%	140,465	7.17%
Total San Juan Unit 1		$ 217,040,804	$ 11,137,695	5.13%	$ 126,527,116	58.30%	$ 15,084,182	6.95%
San Juan Common								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	169,340	803	0.47%	6,501	3.84%	775	0.46%
312.00	Boiler Plant Equipment	8,053,879	4,556,910	56.58%	5,120,792	63.58%	610,485	7.58%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment	49,383	261	0.53%	1,892	3.83%	226	0.46%
Total San Juan Common		$ 8,272,602	$ 4,557,973	55.10%	$ 5,129,185	62.00%	$ 611,486	7.39%
Springerville								
310.00	Rights-of-Way	$ 5,094,433	$ 3,681,571	72.27%	$ 2,866,675	56.27%	$ 2,435,702	47.81%
311.00	Structures and Improvements	141,726,641	69,753,908	49.22%	71,141,108	50.20%	68,092,765	48.05%
312.00	Boiler Plant Equipment	641,687,365	245,587,975	38.27%	271,651,601	42.33%	245,899,655	38.32%
314.00	Turbogenerator Units	173,649,915	50,485,589	29.07%	54,177,144	31.20%	54,881,825	31.60%
315.00	Accessory Electric Equipment	75,864,618	36,828,958	48.55%	35,289,604	46.52%	35,259,694	46.48%
316.00	Miscellaneous Power Plant Equipment	12,528,984	5,054,564	40.34%	4,860,135	38.79%	4,822,925	38.49%
Total Springerville		$ 1,050,551,956	$ 411,392,565	39.16%	$ 439,986,266	41.88%	$ 411,392,565	39.16%

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Springerville Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	20,076,015	8,646,215	43.07%	7,999,339	39.85%	8,571,789	42.70%
312.00	Boiler Plant Equipment	185,682,490	82,449,685	44.40%	78,377,007	42.21%	83,985,834	45.23%
314.00	Turbogenerator Units	49,547,312	24,720,176	49.89%	21,082,315	42.55%	22,591,011	45.59%
315.00	Accessory Electric Equipment	21,214,167	10,429,780	49.16%	10,377,254	48.92%	11,119,872	52.42%
316.00	Miscellaneous Power Plant Equipment	3,277,742	1,342,432	40.96%	1,231,642	37.58%	1,319,781	40.26%
Total Springerville Unit 1		$ 279,797,726	$ 127,588,287	45.60%	$ 119,067,557	42.55%	$ 127,588,287	45.60%
Springerville Unit 1 Common								
310.00	Rights-of-Way	$ 1,143,496	$ 878,769	76.85%	$ 472,348	41.31%	$ 463,859	40.57%
311.00	Structures and Improvements	52,492,826	26,956,787	51.35%	26,686,185	50.84%	26,206,572	49.92%
312.00	Boiler Plant Equipment	14,854,799	7,017,428	47.24%	7,679,618	51.70%	7,541,597	50.77%
314.00	Turbogenerator Units	1,264,322	677,581	53.59%	677,066	53.55%	664,897	52.59%
315.00	Accessory Electric Equipment	9,627,097	4,747,620	49.32%	5,395,718	56.05%	5,298,744	55.04%
316.00	Miscellaneous Power Plant Equipment	1,959,012	968,707	49.45%	1,090,827	55.68%	1,071,222	54.68%
Total Springerville Unit 1 Common		$ 81,341,552	$ 41,246,892	50.71%	$ 42,001,761	51.64%	$ 41,246,892	50.71%
Springerville Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	36,540,030	11,419,075	31.25%	10,676,565	29.22%	10,436,182	28.56%
312.00	Boiler Plant Equipment	295,922,545	90,766,387	30.67%	90,279,732	30.51%	88,247,082	29.82%
314.00	Turbogenerator Units	122,055,348	24,457,076	20.04%	31,729,403	26.00%	31,015,014	25.41%
315.00	Accessory Electric Equipment	42,346,939	19,274,032	45.51%	16,893,181	39.89%	16,512,831	38.99%
316.00	Miscellaneous Power Plant Equipment	6,624,669	2,247,196	33.92%	1,997,634	30.15%	1,952,657	29.48%
Total Springerville Unit 2		$ 503,489,531	$ 148,163,767	29.43%	$ 151,576,515	30.11%	$ 148,163,767	29.43%
Springerville Unit 2 Common (Leasehold Imp.)								
310.00	Rights-of-Way	$ 2,280,838	$ 1,997,938	87.60%	$ 1,638,561	71.84%	$ 1,454,181	63.76%
311.00	Structures and Improvements	32,617,770	22,731,831	69.69%	25,779,019	79.03%	22,878,221	70.14%
312.00	Boiler Plant Equipment	6,282,729	3,192,901	50.82%	4,142,503	65.93%	3,676,366	58.52%
314.00	Turbogenerator Units	782,933	630,756	80.56%	688,361	87.92%	610,903	78.03%
315.00	Accessory Electric Equipment	2,676,415	2,377,526	88.83%	2,623,452	98.02%	2,328,247	86.99%
316.00	Miscellaneous Power Plant Equipment	667,561	496,229	74.33%	540,032	80.90%	479,264	71.79%
Total Springerville Unit 2 Common		$ 45,308,246	$ 31,427,182	69.36%	$ 35,411,927	78.16%	$ 31,427,182	69.36%

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Springerville Coal Handling							
310.00 Rights-of-Way	$ 1,670,099	$ 804,864	48.19%	$ 755,766	45.25%	$ 517,662	31.00%
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	138,944,802	62,161,574	44.74%	91,172,741	65.62%	62,448,776	44.95%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment							
316.00 Miscellaneous Power Plant Equipment							
Total Springerville Coal Handling	$ 140,614,901	$ 62,966,438	44.78%	$ 91,928,507	65.38%	$ 62,966,438	44.78%
Sundt							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	27,475,371	16,379,412	59.61%	15,669,743	57.03%	12,594,871	45.84%
312.00 Boiler Plant Equipment	130,812,626	51,578,275	39.43%	77,263,130	59.06%	62,000,685	47.40%
314.00 Turbogenerator Units	52,481,329	26,949,112	51.35%	31,438,814	59.90%	25,269,581	48.15%
315.00 Accessory Electric Equipment	39,432,489	19,370,802	49.12%	18,220,117	46.21%	14,644,787	37.14%
316.00 Miscellaneous Power Plant Equipment	2,333,493	1,068,696	45.80%	1,040,564	44.59%	836,375	35.84%
Total Sundt	$ 252,535,308	$ 115,346,298	45.68%	$ 143,632,368	56.88%	$ 115,346,298	45.68%
Sundt Unit 1							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	3,926,062	2,175,028	55.40%	2,719,293	69.26%	2,185,686	55.67%
312.00 Boiler Plant Equipment	13,782,181	10,318,349	74.87%	11,489,965	83.37%	9,235,291	67.01%
314.00 Turbogenerator Units	10,237,507	6,554,053	64.02%	7,221,727	70.54%	5,804,608	56.70%
315.00 Accessory Electric Equipment	6,536,315	2,644,455	40.46%	2,607,154	39.89%	2,095,552	32.06%
316.00 Miscellaneous Power Plant Equipment	490,578	230,468	46.98%	231,107	47.11%	185,757	37.86%
Total Sundt Unit 1	$ 34,972,643	$ 21,922,353	62.68%	$ 24,269,245	69.39%	$ 19,506,895	55.78%
Sundt Unit 2							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	2,812,689	1,133,428	40.30%	1,541,596	54.81%	1,239,089	44.05%
312.00 Boiler Plant Equipment	14,371,609	9,423,263	65.57%	11,547,538	80.35%	9,281,566	64.58%
314.00 Turbogenerator Units	8,451,923	5,713,503	67.60%	7,330,945	86.74%	5,892,395	69.72%
315.00 Accessory Electric Equipment	6,205,700	1,836,537	29.59%	2,063,839	33.26%	1,658,852	26.73%
316.00 Miscellaneous Power Plant Equipment	383,824	148,170	38.60%	160,202	41.74%	128,766	33.55%
Total Sundt Unit 2	$ 32,225,745	$ 18,254,901	56.65%	$ 22,644,120	70.27%	$ 18,200,667	56.48%

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Sundt Unit 3								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	2,762,012	1,386,818	50.21%	1,907,128	69.05%	1,532,893	55.50%
312.00	Boiler Plant Equipment	11,980,831	6,673,757	55.70%	9,168,428	76.53%	7,369,308	61.51%
314.00	Turbogenerator Units	14,830,615	8,326,645	56.14%	10,599,263	71.47%	8,519,371	57.44%
315.00	Accessory Electric Equipment	6,140,139	4,200,198	68.41%	4,614,792	75.16%	3,709,232	60.41%
316.00	Miscellaneous Power Plant Equipment	404,717	182,169	45.01%	212,154	52.42%	170,523	42.13%
Total Sundt Unit 3		$ 36,118,314	$ 20,769,587	57.50%	$ 26,501,764	73.37%	$ 21,301,327	58.98%
Sundt Unit 4								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	17,974,608	11,684,139	65.00%	9,501,726	52.86%	7,637,204	42.49%
312.00	Boiler Plant Equipment	80,576,055	25,148,847	31.21%	44,913,910	55.74%	36,100,460	44.80%
314.00	Turbogenerator Units	18,961,284	6,354,911	33.52%	6,286,881	33.16%	5,053,207	26.65%
315.00	Accessory Electric Equipment	20,550,335	10,689,612	52.02%	8,934,333	43.48%	7,181,150	34.94%
316.00	Miscellaneous Power Plant Equipment	1,054,374	507,889	48.17%	437,102	41.46%	351,329	33.32%
Total Sundt Unit 4		$ 139,116,656	$ 54,385,398	39.09%	$ 70,073,951	50.37%	$ 56,323,350	40.49%
Sundt Solar Booster (Areva)								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements							
312.00	Boiler Plant Equipment	10,101,950	14,059	0.14%	143,289	1.42%	14,059	0.14%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment							
Total Sundt Solar Booster (Areva)		$ 10,101,950	$ 14,059	0.14%	$ 143,289	1.42%	$ 14,059	0.14%
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00	Structures and Improvements	$ 761,988	$ 154,938	20.33%	$ 161,792	21.23%	$ 180,486	23.69%
342.00	Fuel Holders, Products and Accessories	750,386	261,338	34.83%	239,586	31.93%	267,269	35.62%
343.00	Prime Movers	76,766	8,524	11.10%	15,312	19.95%	17,081	22.25%
344.00	Generators and Devices	30,772,866	11,025,994	35.83%	9,790,963	31.82%	10,922,248	35.49%
345.00	Accessory Electric Equipment	861,492	268,405	31.16%	295,020	34.25%	329,108	38.20%
346.00	Miscellaneous Power Plant Equipment	376,605	115,469	30.66%	106,205	28.20%	118,476	31.46%
Total DeMoss Petrie Gas Unit 1		$ 33,600,103	$ 11,834,668	35.22%	$ 10,608,878	31.57%	$ 11,834,668	35.22%

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Gila River								
341.00	Structures and Improvements	$ 8,508,950	$ 2,126,825	25.00%	$ 2,212,050	26.00%	$ 2,085,222	24.51%
342.00	Fuel Holders, Products and Accessories	6,783,045	1,695,243	24.99%	1,804,242	26.60%	1,695,857	25.00%
343.00	Prime Movers	188,744,730	45,163,873	23.93%	46,375,817	24.57%	44,920,085	23.80%
344.00	Generators and Devices	32,783,434	8,295,028	25.30%	8,803,240	26.85%	8,534,905	26.03%
345.00	Accessory Electric Equipment	9,030,698	2,242,691	24.83%	2,382,547	26.38%	2,292,546	25.39%
346.00	Miscellaneous Power Plant Equipment	6,799,960	1,679,659	24.70%	1,781,996	26.21%	1,674,704	24.63%
Total Gila River		$ 252,650,817	$ 61,203,319	24.22%	$ 63,359,892	25.08%	$ 61,203,319	24.22%
Gila River Unit 3								
341.00	Structures and Improvements	$ 957,417	$ 259,052	27.06%	$ 252,492	26.37%	$ 244,796	25.57%
342.00	Fuel Holders, Products and Accessories	178,424	40,583	22.75%	43,014	24.11%	41,702	23.37%
343.00	Prime Movers	181,571,712	43,892,641	24.17%	44,985,975	24.78%	43,614,738	24.02%
344.00	Generators and Devices	32,783,434	8,295,028	25.30%	8,803,240	26.85%	8,534,905	26.03%
345.00	Accessory Electric Equipment	6,860,554	1,703,384	24.83%	1,809,283	26.37%	1,754,133	25.57%
346.00	Miscellaneous Power Plant Equipment	135,558	32,986	24.33%	34,451	25.41%	33,400	24.64%
Total Gila River Unit 3		$ 222,487,099	$ 54,223,675	24.37%	$ 55,928,454	25.14%	$ 54,223,675	24.37%
Gila River Common								
341.00	Structures and Improvements	$ 7,551,533	$ 1,867,772	24.73%	$ 1,959,557	25.95%	$ 1,840,426	24.37%
342.00	Fuel Holders, Products and Accessories	6,604,621	1,654,660	25.05%	1,761,228	26.67%	1,654,154	25.05%
343.00	Prime Movers	7,173,018	1,271,232	17.72%	1,389,842	19.38%	1,305,347	18.20%
344.00	Generators and Devices							
345.00	Accessory Electric Equipment	2,170,144	539,307	24.85%	573,264	26.42%	538,413	24.81%
346.00	Miscellaneous Power Plant Equipment	6,664,402	1,646,673	24.71%	1,747,545	26.22%	1,641,303	24.63%
Total Gila River Common		$ 30,163,718	$ 6,979,644	23.14%	$ 7,431,437	24.64%	$ 6,979,644	23.14%
Luna								
341.00	Structures and Improvements	$ 13,232,832	$ 1,357,037	10.26%	$ 2,822,621	21.33%	$ 511,943	3.87%
342.00	Fuel Holders, Products and Accessories	11,352,383	1,178,720	10.38%	2,459,029	21.66%	445,998	3.93%
343.00	Prime Movers	11,151,074	(115,314)	-1.03%	1,256,464	11.27%	227,887	2.04%
344.00	Generators and Devices	9,486,694	(1,277,620)	-13.47%	2,264,984	23.88%	410,803	4.33%
345.00	Accessory Electric Equipment	9,647	114	1.18%	149	1.55%	27	0.28%
346.00	Miscellaneous Power Plant Equipment	7,424,592	744,049	10.02%	1,600,734	21.56%	290,327	3.91%
Total Luna		$ 52,657,222	$ 1,886,985	3.58%	$ 10,403,980	19.76%	$ 1,886,985	3.58%

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North Loop Gas								
341.00	Structures and Improvements	$ 888,601	$ 867,104	97.58%	$ 620,584	69.84%	$ 837,793	94.28%
342.00	Fuel Holders, Products and Accessories	303,037	104,139	34.37%	93,618	30.89%	103,998	34.32%
343.00	Prime Movers	1,890,946	675,327	35.71%	493,389	26.09%	692,530	36.62%
344.00	Generators and Devices	24,062,187	15,675,191	65.14%	12,469,534	51.82%	15,767,332	65.53%
345.00	Accessory Electric Equipment	2,829,171	2,090,869	73.90%	1,541,327	54.48%	2,017,633	71.32%
346.00	Miscellaneous Power Plant Equipment	656,253	639,873	97.50%	469,883	71.60%	633,217	96.49%
Total North Loop Gas		$ 30,630,195	$ 20,052,503	65.47%	$ 15,688,335	51.22%	$ 20,052,503	65.47%
North Loop Gas Unit 1								
341.00	Structures and Improvements	$ 411,070	$ 406,569	98.90%	$ 269,119	65.47%	$ 383,441	93.28%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	678,545	506,913	74.71%	289,463	42.66%	412,426	60.78%
344.00	Generators and Devices	3,582,271	3,792,993	105.88%	2,778,957	77.58%	3,959,451	110.53%
345.00	Accessory Electric Equipment	790,955	763,625	96.54%	513,422	64.91%	731,523	92.49%
346.00	Miscellaneous Power Plant Equipment	306,369	313,164	102.22%	208,046	67.91%	296,423	96.75%
Total North Loop Gas Unit 1		$ 5,769,210	$ 5,783,263	100.24%	$ 4,059,007	70.36%	$ 5,783,263	100.24%
North Loop Gas Unit 2								
341.00	Structures and Improvements	$ 196,078	$ 215,565	109.94%	$ 162,333	82.79%	$ 207,598	105.88%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	263,450	(327,630)	-124.36%	(111,031)	-42.14%	(141,991)	-53.90%
344.00	Generators and Devices	3,239,719	3,643,451	112.46%	2,738,191	84.52%	3,501,707	108.09%
345.00	Accessory Electric Equipment	504,895	505,786	100.18%	366,742	72.64%	469,004	92.89%
346.00	Miscellaneous Power Plant Equipment	128,559	148,230	115.30%	116,577	90.68%	149,084	115.97%
Total North Loop Gas Unit 2		$ 4,332,701	$ 4,185,401	96.60%	$ 3,272,812	75.54%	$ 4,185,401	96.60%
North Loop Gas Unit 3								
341.00	Structures and Improvements	$ 196,078	$ 212,395	108.32%	$ 159,855	81.53%	$ 214,232	109.26%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	948,951	496,044	52.27%	314,956	33.19%	422,094	44.48%
344.00	Generators and Devices	3,030,531	3,333,807	110.01%	2,542,347	83.89%	3,407,168	112.43%
345.00	Accessory Electric Equipment	503,907	493,376	97.91%	360,401	71.52%	482,997	95.85%
346.00	Miscellaneous Power Plant Equipment	128,559	144,847	112.67%	114,895	89.37%	153,978	119.77%
Total North Loop Gas Unit 3		$ 4,808,026	$ 4,680,469	97.35%	$ 3,492,454	72.64%	$ 4,680,469	97.35%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2014

Statement C

Account Description		Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G	H=G/B
North Loop Gas Unit 4								
341.00	Structures and Improvements	$ 85,375	$ 32,575	38.16%	$ 29,277	34.29%	$ 32,523	38.09%
342.00	Fuel Holders, Products and Accessories	303,037	104,139	34.37%	93,618	30.89%	103,998	34.32%
343.00	Prime Movers							
344.00	Generators and Devices	14,209,666	4,904,940	34.52%	4,410,039	31.04%	4,899,007	34.48%
345.00	Accessory Electric Equipment	1,029,414	328,082	31.87%	300,762	29.22%	334,109	32.46%
346.00	Miscellaneous Power Plant Equipment	92,766	33,632	36.26%	30,365	32.73%	33,732	36.36%
Total North Loop Gas Unit 4		$ 15,720,258	$ 5,403,369	34.37%	$ 4,864,061	30.94%	$ 5,403,369	34.37%
Solar Units (Generators and Devices)								
344.00	DeMoss Petrie	$ 1,146,081	$ 334,209	29.16%	$ 509,290	44.44%	$ 610,990	53.31%
344.00	Fort Huachuca	36,709,538	73,938	0.20%	688,304	1.88%	825,751	2.25%
344.00	HQ Rooftop	303,184	45,437	14.99%	28,424	9.38%	34,099	11.25%
344.00	OH Rooftop	2,594,590	399,653	15.40%	340,540	13.13%	408,542	15.75%
344.00	OH Test Yard	388,459	233,584	60.13%	162,716	41.89%	195,208	50.25%
344.00	Prairie Fire	19,036,520	1,980,433	10.40%	1,784,674	9.38%	2,141,054	11.25%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	17,515,266	60.89%	12,826,310	44.59%	15,387,588	53.49%
344.00	Springerville Site 4	7,873,874	1,606,533	20.40%	1,328,716	16.88%	1,594,047	20.24%
344.00	Tucson	87,198	71,385	81.86%	52,907	60.68%	63,472	72.79%
344.00	U of A Tech Park Site 1	7,723,832	1,576,302	20.41%	1,303,397	16.88%	1,563,671	20.24%
344.00	U of A Tech Park Site 2	19,191,952	2,956,201	15.40%	2,518,944	13.13%	3,021,950	15.75%
344.00	White Mountain	46,499,099	99,392	0.21%	871,858	1.88%	1,045,959	2.25%
Total Solar Units		$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
Sundt Gas								
341.00	Structures and Improvements	$ 11,090	$ 11,891	107.22%	$ 7,620	68.71%	$ 11,521	103.89%
342.00	Fuel Holders, Products and Accessories	788,336	582,161	73.85%	294,454	37.35%	445,221	56.48%
343.00	Prime Movers	141,618	139,570	98.55%	74,554	52.64%	112,728	79.60%
344.00	Generators and Devices	8,382,044	8,804,904	105.04%	5,925,140	70.69%	8,956,775	106.86%
345.00	Accessory Electric Equipment	1,078,811	1,070,884	99.27%	713,919	66.18%	1,079,672	100.08%
346.00	Miscellaneous Power Plant Equipment	49,750	55,130	110.81%	38,725	77.84%	58,624	117.84%
Total Sundt Gas		$ 10,451,649	$ 10,664,539	102.04%	$ 7,054,412	67.50%	$ 10,664,539	102.04%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2014

Statement C

Account Description		Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G	H=G/B
Sundt Gas Unit 1								
341.00	Structures and Improvements	$ 5,545	$ 5,964	107.55%	$ 3,808	68.67%	$ 5,722	103.19%
342.00	Fuel Holders, Products and Accessories	394,168	291,435	73.94%	147,155	37.33%	221,118	56.10%
343.00	Prime Movers	70,809	70,514	99.58%	37,259	52.62%	55,986	79.07%
344.00	Generators and Devices	4,315,668	4,541,928	105.24%	3,075,415	71.26%	4,621,184	107.08%
345.00	Accessory Electric Equipment	516,231	514,444	99.65%	345,496	66.93%	519,149	100.57%
346.00	Miscellaneous Power Plant Equipment	19,906	22,217	111.61%	15,534	78.03%	23,341	117.26%
Total Sundt Gas Unit 1		$ 5,322,327	$ 5,446,501	102.33%	$ 3,624,667	68.10%	$ 5,446,501	102.33%
Sundt Gas Unit 2								
341.00	Structures and Improvements	$ 5,545	$ 5,927	106.89%	$ 3,812	68.74%	$ 5,799	104.58%
342.00	Fuel Holders, Products and Accessories	394,168	290,725	73.76%	147,299	37.37%	224,102	56.85%
343.00	Prime Movers	70,809	69,056	97.52%	37,295	52.67%	56,742	80.13%
344.00	Generators and Devices	4,066,376	4,262,976	104.83%	2,849,724	70.08%	4,335,590	106.62%
345.00	Accessory Electric Equipment	562,580	556,440	98.91%	368,424	65.49%	560,522	99.63%
346.00	Miscellaneous Power Plant Equipment	29,844	32,913	110.28%	23,191	77.71%	35,283	118.22%
Total Sundt Gas Unit 2		$ 5,129,322	$ 5,218,038	101.73%	$ 3,429,745	66.87%	$ 5,218,038	101.73%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
STEAM PRODUCTION								
310.00	Rights-of-Way	$ 5,106,662	$ 2,446,505	47.91%	$ 648	0.01%	$ 2,447,153	47.92%
311.00	Structures and Improvements	205,277,689	79,186,489	38.58%	18,061,746	8.80%	97,248,235	47.37%
312.00	Boiler Plant Equipment	1,091,953,161	380,425,888	34.84%	65,856,752	6.03%	446,282,641	40.87%
314.00	Turbogenerator Units	303,041,923	92,264,412	30.45%	15,887,547	5.24%	108,151,958	35.69%
315.00	Accessory Electric Equipment	144,581,471	52,957,876	36.63%	9,150,049	6.33%	62,107,925	42.96%
316.00	Miscellaneous Power Plant Equipment	25,222,863	10,104,962	40.06%	1,178,742	4.67%	11,283,704	44.74%
	Total Steam Production Plant	$ 1,775,183,769	$ 617,386,132	34.78%	$ 110,135,484	6.20%	$ 727,521,616	40.98%
OTHER PRODUCTION								
Non-Solar								
341.00	Structures and Improvements	$ 23,403,461	$ 3,243,160	13.86%	$ 383,805	1.64%	$ 3,626,965	15.50%
342.00	Fuel Holders, Products and Accessories	19,977,187	2,718,793	13.61%	239,548	1.20%	2,958,341	14.81%
343.00	Prime Movers	202,005,134	42,290,760	20.94%	3,679,551	1.82%	45,970,311	22.76%
344.00	Generators and Devices	105,487,225	40,814,739	38.69%	3,777,323	3.58%	44,592,063	42.27%
345.00	Accessory Electric Equipment	13,809,819	5,200,835	37.66%	518,151	3.75%	5,718,985	41.41%
346.00	Miscellaneous Power Plant Equipment	15,307,160	2,504,902	16.36%	270,446	1.77%	2,775,348	18.13%
	Total Non-Solar	$ 379,989,986	$ 96,773,189	25.47%	$ 8,868,825	2.33%	$ 105,642,014	27.80%
Solar								
344.00	Generators and Devices	$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%
	Total Solar	$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%
	Total Other Production Plant	$ 550,310,918	$ 122,384,934	22.24%	$ 10,149,412	1.84%	$ 132,534,346	24.08%
DISTRIBUTION PLANT								
360.RW	Rights-of-Way	$ 7,865,073	$ 3,720,941	47.31%	$ -		$ 3,720,941	47.31%
361.00	Structures and Improvements	11,402,474	2,417,039	21.20%			2,417,039	21.20%
362.00	Station Equipment	157,067,530	48,009,871	30.57%			48,009,871	30.57%
364.00	Poles, Towers and Fixtures	222,006,967	67,521,575	30.41%			67,521,575	30.41%
365.00	Overhead Conductors and Devices	175,675,966	63,847,797	36.34%			63,847,797	36.34%
366.00	Underground Conduit	58,725,355	23,421,293	39.88%			23,421,293	39.88%
367.00	Underground Conductors and Devices	297,183,135	115,677,372	38.92%			115,677,372	38.92%
368.OH	Line Transformers - Overhead	103,657,922	39,735,096	38.33%			39,735,096	38.33%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
368.UG Line Transformers - Underground	172,890,932	65,875,110	38.10%			65,875,110	38.10%
369.OH Services - Overhead	17,542,236	7,990,202	45.55%			7,990,202	45.55%
369.UG Services - Underground	112,947,714	35,939,682	31.82%			35,939,682	31.82%
370.00 Meters	44,869,823	10,843,126	24.17%			10,843,126	24.17%
373.00 Street Lighting and Signal Systems	11,778,362	5,006,268	42.50%			5,006,268	42.50%
Total Distribution Plant	$ 1,393,613,489	$ 490,005,372	35.16%	$ -		$ 490,005,372	35.16%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 135,680,348	$ 21,570,039	15.90%	$ 126,776	0.09%	$ 21,696,815	15.99%
392.C0 Transportation - Class 0	1,238,946	458,248	36.99%	(53,946)	-4.35%	404,302	32.63%
392.C1 Transportation - Class 1	7,718,183	3,304,203	42.81%	(408,989)	-5.30%	2,895,214	37.51%
392.C2 Transportation - Class 2	3,839,907	1,609,294	41.91%	(189,552)	-4.94%	1,419,742	36.97%
392.C3 Transportation - Class 3	2,076,936	1,052,793	50.69%	(131,035)	-6.31%	921,757	44.38%
392.C4 Transportation - Class 4	2,935,027	1,180,337	40.22%	(129,837)	-4.42%	1,050,500	35.79%
392.C5 Transportation - Class 5	7,982,715	3,474,021	43.52%	(448,803)	-5.62%	3,025,218	37.90%
392.C6 Transportation - Class 6	365,200	80,311	21.99%	(12,047)	-3.30%	68,264	18.69%
392.C7 Transportation - Class 7	1,047,216	410,010	39.15%	(61,501)	-5.87%	348,508	33.28%
392.C8 Transportation - Class 8	9,957,500	3,613,292	36.29%	(530,533)	-5.33%	3,082,759	30.96%
392.C9 Transportation - Class 9	4,252,286	1,247,812	29.34%	(178,945)	-4.21%	1,068,867	25.14%
396.00 Power Operatied Equipment	11,860,940	2,412,819	20.34%	87,170	0.73%	2,499,990	21.08%
397.EM EMS and SCADA Equipment	11,304,371	3,110,221	27.51%			3,110,221	27.51%
Total Depreciable	$ 200,259,575	$ 43,523,399	21.73%	$ (1,931,242)	-0.96%	$ 41,592,158	20.77%
Amortizable							
391.00 Furniture and Office Equipment	$ 23,964,411	$ 7,698,753	32.13%	$ -		$ 7,698,753	32.13%
391.20 Network and Data Equipment	29,359,636	14,913,970	50.80%			14,913,970	50.80%
393.00 Stores Equipment	1,852,479	840,197	45.36%			840,197	45.36%
394.00 Tools, Shop and Garage Equipment	6,934,368	2,858,589	41.22%			2,858,589	41.22%
395.00 Laboratory Equipment	5,091,270	2,395,826	47.06%			2,395,826	47.06%
397.20 Telecommunications Equipment	57,456,141	19,662,636	34.22%			19,662,636	34.22%
398.00 Miscellaneous Equipment	4,348,209	1,815,347	41.75%			1,815,347	41.75%
Total Amortizable	$ 129,006,514	$ 50,185,318	38.90%	$ -		$ 50,185,318	38.90%
Total General Plant	$ 329,266,089	$ 93,708,717	28.46%	$ (1,931,242)	-0.59%	$ 91,777,476	27.87%
SUBTOTAL	$ 4,048,374,265	$ 1,323,485,155	32.69%	$ 118,353,655	2.92%	$ 1,441,838,810	35.62%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
NET SALVAGE							
108.02 Distribution	$ 1,393,613,489	$ -		$ 84,815,412	6.09%	$ 84,815,412	6.09%
Total Net Salvage	$ 1,393,613,489	$ -		$ 84,815,412	6.09%	$ 84,815,412	6.09%
TOTAL UTILITY	$ 4,048,374,265	$ 1,323,485,155	32.69%	$ 203,169,066	5.02%	$ 1,526,654,221	37.71%
STEAM PRODUCTION (by Unit)							
Four Corners							
310.00 Rights-of-Way	$ -	$ -	#DIV/0!	$ -		$ -	
311.00 Structures and Improvements	2,982,777	1,790,395	60.02%	117,850	3.95%	1,908,245	63.98%
312.00 Boiler Plant Equipment	76,402,061	56,979,152	74.58%	3,365,936	4.41%	60,345,088	78.98%
314.00 Turbogenerator Units	12,359,480	8,247,191	66.73%	583,323	4.72%	8,830,514	71.45%
315.00 Accessory Electric Equipment	4,390,980	1,526,418	34.76%	137,054	3.12%	1,663,472	37.88%
316.00 Miscellaneous Power Plant Equipment	3,832,234	2,401,796	62.67%	153,288	4.00%	2,555,084	66.67%
Total Four Corners	$ 99,967,532	$ 70,944,953	70.97%	$ 4,357,451	4.36%	$ 75,302,403	75.33%
Four Corners Unit 4							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,524,414	945,048	61.99%	59,082	3.88%	1,004,130	65.87%
312.00 Boiler Plant Equipment	39,609,538	30,452,510	76.88%	1,501,983	3.79%	31,954,492	80.67%
314.00 Turbogenerator Units	7,179,362	4,764,500	66.36%	333,469	4.64%	5,097,969	71.01%
315.00 Accessory Electric Equipment	2,274,836	839,579	36.91%	78,525	3.45%	918,105	40.36%
316.00 Miscellaneous Power Plant Equipment	1,929,161	1,244,724	64.52%	76,564	3.97%	1,321,288	68.49%
Total Four Corners Unit 4	$ 52,517,311	$ 38,246,361	72.83%	$ 2,049,623	3.90%	$ 40,295,985	76.73%
Four Corners Unit 5							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,458,363	845,348	57.97%	58,768	4.03%	904,116	62.00%
312.00 Boiler Plant Equipment	36,792,523	26,526,643	72.10%	1,863,953	5.07%	28,390,596	77.16%
314.00 Turbogenerator Units	5,180,118	3,482,691	67.23%	249,853	4.82%	3,732,544	72.06%
315.00 Accessory Electric Equipment	2,116,144	686,839	32.46%	58,529	2.77%	745,368	35.22%
316.00 Miscellaneous Power Plant Equipment	1,903,073	1,157,071	60.80%	76,724	4.03%	1,233,795	64.83%
Total Four Corners Unit 5	$ 47,450,221	$ 32,698,592	68.91%	$ 2,307,827	4.86%	$ 35,006,419	73.78%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Navajo								
310.00	Rights-of-Way	$ 12,229	$ 10,803	88.34%	$ 648	5.30%	$ 11,451	93.64%
311.00	Structures and Improvements	18,655,156	12,786,208	68.54%	778,935	4.18%	13,565,143	72.72%
312.00	Boiler Plant Equipment	88,544,201	63,639,561	71.87%	3,934,265	4.44%	67,573,826	76.32%
314.00	Turbogenerator Units	20,255,526	14,947,385	73.79%	904,267	4.46%	15,851,652	78.26%
315.00	Accessory Electric Equipment	14,829,858	9,298,812	62.70%	555,168	3.74%	9,853,980	66.45%
316.00	Miscellaneous Power Plant Equipment	4,518,597	2,766,505	61.22%	162,125	3.59%	2,928,630	64.81%
Total Navajo		$ 146,815,567	$ 103,449,273	70.46%	$ 6,335,409	4.32%	$ 109,784,682	74.78%
Navajo Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	3,190,563	2,602,211	81.56%	130,111	4.08%	2,732,322	85.64%
312.00	Boiler Plant Equipment	27,198,582	19,904,578	73.18%	995,229	3.66%	20,899,807	76.84%
314.00	Turbogenerator Units	6,860,989	5,010,040	73.02%	255,954	3.73%	5,265,994	76.75%
315.00	Accessory Electric Equipment	3,544,300	2,201,346	62.11%	113,340	3.20%	2,314,686	65.31%
316.00	Miscellaneous Power Plant Equipment	471,227	386,830	82.09%	18,955	4.02%	405,785	86.11%
Total Navajo Unit 1		$ 41,265,661	$ 30,105,004	72.95%	$ 1,513,588	3.67%	$ 31,618,592	76.62%
Navajo Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	1,802,685	1,413,416	78.41%	95,946	5.32%	1,509,362	83.73%
312.00	Boiler Plant Equipment	26,882,286	19,927,056	74.13%	1,401,448	5.21%	21,328,503	79.34%
314.00	Turbogenerator Units	6,926,050	5,011,523	72.36%	334,587	4.83%	5,346,110	77.19%
315.00	Accessory Electric Equipment	3,172,330	2,183,748	68.84%	149,721	4.72%	2,333,469	73.56%
316.00	Miscellaneous Power Plant Equipment	515,874	440,017	85.30%	28,379	5.50%	468,397	90.80%
Total Navajo Unit 2		$ 39,299,225	$ 28,975,760	73.73%	$ 2,010,081	5.11%	$ 30,985,841	78.85%
Navajo Unit 3								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	3,681,511	3,055,737	83.00%	184,940	5.02%	3,240,677	88.03%
312.00	Boiler Plant Equipment	27,718,514	20,005,857	72.18%	1,320,505	4.76%	21,326,362	76.94%
314.00	Turbogenerator Units	6,178,944	4,851,335	78.51%	308,818	5.00%	5,160,153	83.51%
315.00	Accessory Electric Equipment	5,139,872	3,913,169	76.13%	221,882	4.32%	4,135,051	80.45%
316.00	Miscellaneous Power Plant Equipment	549,362	469,492	85.46%	24,310	4.43%	493,802	89.89%
Total Navajo Unit 3		$ 43,268,203	$ 32,295,589	74.64%	$ 2,060,456	4.76%	$ 34,356,045	79.40%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Navajo Common								
310.00	Rights-of-Way	$ 12,229	$ 10,803	88.34%	$ 648	5.30%	$ 11,451	93.64%
311.00	Structures and Improvements	9,980,397	5,714,845	57.26%	367,937	3.69%	6,082,782	60.95%
312.00	Boiler Plant Equipment	6,744,819	3,802,071	56.37%	217,083	3.22%	4,019,154	59.59%
314.00	Turbogenerator Units	289,543	74,488	25.73%	4,907	1.69%	79,395	27.42%
315.00	Accessory Electric Equipment	2,973,356	1,000,549	33.65%	70,225	2.36%	1,070,774	36.01%
316.00	Miscellaneous Power Plant Equipment	2,982,134	1,470,165	49.30%	90,482	3.03%	1,560,647	52.33%
Total Navajo Common		$ 22,982,478	$ 12,072,920	52.53%	$ 751,283	3.27%	$ 12,824,203	55.80%
San Juan								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	14,437,744	987,235	6.84%	99,976	0.69%	1,087,211	7.53%
312.00	Boiler Plant Equipment	154,506,908	9,395,805	6.08%	1,067,582	0.69%	10,463,387	6.77%
314.00	Turbogenerator Units	44,295,673	3,010,479	6.80%	307,909	0.70%	3,318,387	7.49%
315.00	Accessory Electric Equipment	10,063,526	622,176	6.18%	63,816	0.63%	685,993	6.82%
316.00	Miscellaneous Power Plant Equipment	2,009,555	127,336	6.34%	13,354	0.66%	140,690	7.00%
Total San Juan		$ 225,313,406	$ 14,143,031	6.28%	$ 1,552,637	0.69%	$ 15,695,668	6.97%
San Juan Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	14,268,404	986,462	6.91%	99,974	0.70%	1,086,436	7.61%
312.00	Boiler Plant Equipment	146,453,029	9,004,800	6.15%	848,101	0.58%	9,852,901	6.73%
314.00	Turbogenerator Units	44,295,673	3,010,479	6.80%	307,909	0.70%	3,318,387	7.49%
315.00	Accessory Electric Equipment	10,063,526	622,176	6.18%	63,816	0.63%	685,993	6.82%
316.00	Miscellaneous Power Plant Equipment	1,960,172	127,111	6.48%	13,354	0.68%	140,465	7.17%
Total San Juan Unit 1		$ 217,040,804	$ 13,751,027	6.34%	$ 1,333,155	0.61%	$ 15,084,182	6.95%
San Juan Common								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	169,340	773	0.46%	2	0.00%	775	0.46%
312.00	Boiler Plant Equipment	8,053,879	391,005	4.85%	219,481	2.73%	610,485	7.58%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment	49,383	226	0.46%			226	0.46%
Total San Juan Common		$ 8,272,602	$ 392,004	4.74%	$ 219,482	2.65%	$ 611,486	7.39%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Springerville								
310.00	Rights-of-Way	$ 5,094,433	$ 2,435,702	47.81%	$ -		$ 2,435,702	47.81%
311.00	Structures and Improvements	141,726,641	55,092,231	38.87%	13,000,534	9.17%	68,092,765	48.05%
312.00	Boiler Plant Equipment	641,687,365	208,836,791	32.54%	37,062,864	5.78%	245,899,655	38.32%
314.00	Turbogenerator Units	173,649,915	51,074,703	29.41%	3,807,122	2.19%	54,881,825	31.60%
315.00	Accessory Electric Equipment	75,864,618	32,139,515	42.36%	3,120,179	4.11%	35,259,694	46.48%
316.00	Miscellaneous Power Plant Equipment	12,528,984	4,299,916	34.32%	523,009	4.17%	4,822,925	38.49%
Total Springerville		$ 1,050,551,956	$ 353,878,858	33.69%	$ 57,513,707	5.47%	$ 411,392,565	39.16%
Springerville Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	20,076,015	7,957,893	39.64%	613,897	3.06%	8,571,789	42.70%
312.00	Boiler Plant Equipment	185,682,490	78,118,253	42.07%	5,867,581	3.16%	83,985,834	45.23%
314.00	Turbogenerator Units	49,547,312	21,018,043	42.42%	1,572,967	3.17%	22,591,011	45.59%
315.00	Accessory Electric Equipment	21,214,167	10,493,761	49.47%	626,111	2.95%	11,119,872	52.42%
316.00	Miscellaneous Power Plant Equipment	3,277,742	1,220,854	37.25%	98,927	3.02%	1,319,781	40.26%
Total Springerville Unit 1		$ 279,797,726	$ 118,808,805	42.46%	$ 8,779,482	3.14%	$ 127,588,287	45.60%
Springerville Unit 1 Common								
310.00	Rights-of-Way	$ 1,143,496	$ 463,859	40.57%	$ -		$ 463,859	40.57%
311.00	Structures and Improvements	52,492,826	21,135,153	40.26%	5,071,418	9.66%	26,206,572	49.92%
312.00	Boiler Plant Equipment	14,854,799	6,175,972	41.58%	1,365,625	9.19%	7,541,597	50.77%
314.00	Turbogenerator Units	1,264,322	550,930	43.58%	113,967	9.01%	664,897	52.59%
315.00	Accessory Electric Equipment	9,627,097	4,523,933	46.99%	774,811	8.05%	5,298,744	55.04%
316.00	Miscellaneous Power Plant Equipment	1,959,012	908,077	46.35%	163,145	8.33%	1,071,222	54.68%
Total Springerville Unit 1 Common		$ 81,341,552	$ 33,757,925	41.50%	$ 7,488,967	9.21%	$ 41,246,892	50.71%
Springerville Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	36,540,030	9,853,583	26.97%	582,599	1.59%	10,436,182	28.56%
312.00	Boiler Plant Equipment	295,922,545	83,669,199	28.27%	4,577,883	1.55%	88,247,082	29.82%
314.00	Turbogenerator Units	122,055,348	29,067,492	23.82%	1,947,522	1.60%	31,015,014	25.41%
315.00	Accessory Electric Equipment	42,346,939	15,451,630	36.49%	1,061,201	2.51%	16,512,831	38.99%
316.00	Miscellaneous Power Plant Equipment	6,624,669	1,828,187	27.60%	124,470	1.88%	1,952,657	29.48%
Total Springerville Unit 2		$ 503,489,531	$ 139,870,091	27.78%	$ 8,293,675	1.65%	$ 148,163,767	29.43%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Springerville Unit 2 Common (Leasehold Imp.)								
310.00	Rights-of-Way	$ 2,280,838	$ 1,454,181	63.76%	$ -		$ 1,454,181	63.76%
311.00	Structures and Improvements	32,617,770	16,145,601	49.50%	6,732,620	20.64%	22,878,221	70.14%
312.00	Boiler Plant Equipment	6,282,729	2,479,582	39.47%	1,196,784	19.05%	3,676,366	58.52%
314.00	Turbogenerator Units	782,933	438,237	55.97%	172,665	22.05%	610,903	78.03%
315.00	Accessory Electric Equipment	2,676,415	1,670,192	62.40%	658,056	24.59%	2,328,247	86.99%
316.00	Miscellaneous Power Plant Equipment	667,561	342,797	51.35%	136,467	20.44%	479,264	71.79%
Total Springerville Unit 2 Common		$ 45,308,246	$ 22,530,590	49.73%	$ 8,896,592	19.64%	$ 31,427,182	69.36%
Springerville Coal Handling								
310.00	Rights-of-Way	$ 1,670,099	$ 517,662	31.00%	$ -		$ 517,662	31.00%
311.00	Structures and Improvements							
312.00	Boiler Plant Equipment	138,944,802	38,393,785	27.63%	24,054,991	17.31%	62,448,776	44.95%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment							
Total Springerville Coal Handling		$ 140,614,901	$ 38,911,447	27.67%	$ 24,054,991	17.11%	$ 62,966,438	44.78%
Sundt								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	27,475,371	8,530,420	31.05%	4,064,451	14.79%	12,594,871	45.84%
312.00	Boiler Plant Equipment	130,812,626	41,574,579	31.78%	20,426,105	15.61%	62,000,685	47.40%
314.00	Turbogenerator Units	52,481,329	14,984,654	28.55%	10,284,927	19.60%	25,269,581	48.15%
315.00	Accessory Electric Equipment	39,432,489	9,370,955	23.76%	5,273,832	13.37%	14,644,787	37.14%
316.00	Miscellaneous Power Plant Equipment	2,333,493	509,409	21.83%	326,965	14.01%	836,375	35.84%
Total Sundt		$ 252,535,308	$ 74,970,017	29.69%	$ 40,376,281	15.99%	$ 115,346,298	45.68%
Sundt Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	3,926,062	1,323,828	33.72%	861,859	21.95%	2,185,686	55.67%
312.00	Boiler Plant Equipment	13,782,181	5,488,270	39.82%	3,747,021	27.19%	9,235,291	67.01%
314.00	Turbogenerator Units	10,237,507	3,468,639	33.88%	2,335,969	22.82%	5,804,608	56.70%
315.00	Accessory Electric Equipment	6,536,315	1,200,408	18.37%	895,144	13.69%	2,095,552	32.06%
316.00	Miscellaneous Power Plant Equipment	490,578	111,778	22.79%	73,978	15.08%	185,757	37.86%
Total Sundt Unit 1		$ 34,972,643	$ 11,592,923	33.15%	$ 7,913,971	22.63%	$ 19,506,895	55.78%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Sundt Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	2,812,689	677,497	24.09%	561,592	19.97%	1,239,089	44.05%
312.00	Boiler Plant Equipment	14,371,609	5,471,538	38.07%	3,810,028	26.51%	9,281,566	64.58%
314.00	Turbogenerator Units	8,451,923	3,432,107	40.61%	2,460,287	29.11%	5,892,395	69.72%
315.00	Accessory Electric Equipment	6,205,700	916,155	14.76%	742,697	11.97%	1,658,852	26.73%
316.00	Miscellaneous Power Plant Equipment	383,824	71,194	18.55%	57,572	15.00%	128,766	33.55%
Total Sundt Unit 2		$ 32,225,745	$ 10,568,492	32.80%	$ 7,632,176	23.68%	$ 18,200,667	56.48%
Sundt Unit 3								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	2,762,012	809,005	29.29%	723,887	26.21%	1,532,893	55.50%
312.00	Boiler Plant Equipment	11,980,831	4,038,318	33.71%	3,330,991	27.80%	7,369,308	61.51%
314.00	Turbogenerator Units	14,830,615	4,546,648	30.66%	3,972,723	26.79%	8,519,371	57.44%
315.00	Accessory Electric Equipment	6,140,139	1,965,769	32.02%	1,743,463	28.39%	3,709,232	60.41%
316.00	Miscellaneous Power Plant Equipment	404,717	84,977	21.00%	85,546	21.14%	170,523	42.13%
Total Sundt Unit 3		$ 36,118,314	$ 11,444,716	31.69%	$ 9,856,611	27.29%	$ 21,301,327	58.98%
Sundt Unit 4								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	17,974,608	5,720,090	31.82%	1,917,114	10.67%	7,637,204	42.49%
312.00	Boiler Plant Equipment	80,576,055	26,562,451	32.97%	9,538,009	11.84%	36,100,460	44.80%
314.00	Turbogenerator Units	18,961,284	3,537,259	18.66%	1,515,947	7.99%	5,053,207	26.65%
315.00	Accessory Electric Equipment	20,550,335	5,288,623	25.73%	1,892,528	9.21%	7,181,150	34.94%
316.00	Miscellaneous Power Plant Equipment	1,054,374	241,460	22.90%	109,869	10.42%	351,329	33.32%
Total Sundt Unit 4		$ 139,116,656	$ 41,349,883	29.72%	$ 14,973,467	10.76%	$ 56,323,350	40.49%
Sundt Solar Booster (Areva)								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements							
312.00	Boiler Plant Equipment	10,101,950	14,003	0.14%	56	0.00%	14,059	0.14%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment							
Total Sundt Solar Booster (Areva)		$ 10,101,950	$ 14,003	0.14%	$ 56	0.00%	$ 14,059	0.14%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00	Structures and Improvements	$ 761,988	$ 154,739	20.31%	$ 25,746	3.38%	$ 180,486	23.69%
342.00	Fuel Holders, Products and Accessories	750,386	244,657	32.60%	22,612	3.01%	267,269	35.62%
343.00	Prime Movers	76,766	10,353	13.49%	6,729	8.77%	17,081	22.25%
344.00	Generators and Devices	30,772,866	9,953,323	32.34%	968,925	3.15%	10,922,248	35.49%
345.00	Accessory Electric Equipment	861,492	266,238	30.90%	62,870	7.30%	329,108	38.20%
346.00	Miscellaneous Power Plant Equipment	376,605	108,408	28.79%	10,068	2.67%	118,476	31.46%
Total DeMoss Petrie Gas Unit 1		$ 33,600,103	$ 10,737,719	31.96%	$ 1,096,949	3.26%	$ 11,834,668	35.22%
Gila River								
341.00	Structures and Improvements	$ 8,508,950	$ 1,923,845	22.61%	$ 161,377	1.90%	$ 2,085,222	24.51%
342.00	Fuel Holders, Products and Accessories	6,783,045	1,564,479	23.06%	131,378	1.94%	1,695,857	25.00%
343.00	Prime Movers	188,744,730	41,476,345	21.97%	3,443,741	1.82%	44,920,085	23.80%
344.00	Generators and Devices	32,783,434	7,880,799	24.04%	654,106	2.00%	8,534,905	26.03%
345.00	Accessory Electric Equipment	9,030,698	2,116,389	23.44%	176,157	1.95%	2,292,546	25.39%
346.00	Miscellaneous Power Plant Equipment	6,799,960	1,544,958	22.72%	129,746	1.91%	1,674,704	24.63%
Total Gila River		$ 252,650,817	$ 56,506,815	22.37%	$ 4,696,504	1.86%	$ 61,203,319	24.22%
Gila River Unit 3								
341.00	Structures and Improvements	$ 957,417	$ 226,035	23.61%	$ 18,761	1.96%	$ 244,796	25.57%
342.00	Fuel Holders, Products and Accessories	178,424	38,506	21.58%	3,196	1.79%	41,702	23.37%
343.00	Prime Movers	181,571,712	40,272,150	22.18%	3,342,588	1.84%	43,614,738	24.02%
344.00	Generators and Devices	32,783,434	7,880,799	24.04%	654,106	2.00%	8,534,905	26.03%
345.00	Accessory Electric Equipment	6,860,554	1,619,698	23.61%	134,435	1.96%	1,754,133	25.57%
346.00	Miscellaneous Power Plant Equipment	135,558	30,841	22.75%	2,560	1.89%	33,400	24.64%
Total Gila River Unit 3		$ 222,487,099	$ 50,068,029	22.50%	$ 4,155,646	1.87%	$ 54,223,675	24.37%
Gila River Common								
341.00	Structures and Improvements	$ 7,551,533	$ 1,697,810	22.48%	$ 142,616	1.89%	$ 1,840,426	24.37%
342.00	Fuel Holders, Products and Accessories	6,604,621	1,525,973	23.10%	128,182	1.94%	1,654,154	25.05%
343.00	Prime Movers	7,173,018	1,204,195	16.79%	101,152	1.41%	1,305,347	18.20%
344.00	Generators and Devices							
345.00	Accessory Electric Equipment	2,170,144	496,691	22.89%	41,722	1.92%	538,413	24.81%
346.00	Miscellaneous Power Plant Equipment	6,664,402	1,514,118	22.72%	127,186	1.91%	1,641,303	24.63%
Total Gila River Common		$ 30,163,718	$ 6,438,786	21.35%	$ 540,858	1.79%	$ 6,979,644	23.14%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

	Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
	A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Luna								
341.00	Structures and Improvements	$ 13,232,832	$ 429,269	3.24%	$ 82,673	0.62%	$ 511,943	3.87%
342.00	Fuel Holders, Products and Accessories	11,352,383	375,419	3.31%	70,579	0.62%	445,998	3.93%
343.00	Prime Movers	11,151,074	139,519	1.25%	88,368	0.79%	227,887	2.04%
344.00	Generators and Devices	9,486,694	250,509	2.64%	160,294	1.69%	410,803	4.33%
345.00	Accessory Electric Equipment	9,647	23	0.24%	4	0.04%	27	0.28%
346.00	Miscellaneous Power Plant Equipment	7,424,592	243,455	3.28%	46,873	0.63%	290,327	3.91%
	Total Luna	$ 52,657,222	$ 1,438,194	2.73%	$ 448,791	0.85%	$ 1,886,985	3.58%
North Loop Gas								
341.00	Structures and Improvements	$ 888,601	$ 724,043	81.48%	$ 113,750	12.80%	$ 837,793	94.28%
342.00	Fuel Holders, Products and Accessories	303,037	98,389	32.47%	5,608	1.85%	103,998	34.32%
343.00	Prime Movers	1,890,946	554,189	29.31%	138,341	7.32%	692,530	36.62%
344.00	Generators and Devices	24,062,187	13,969,357	58.06%	1,797,976	7.47%	15,767,332	65.53%
345.00	Accessory Electric Equipment	2,829,171	1,761,821	62.27%	255,813	9.04%	2,017,633	71.32%
346.00	Miscellaneous Power Plant Equipment	656,253	550,697	83.92%	82,520	12.57%	633,217	96.49%
	Total North Loop Gas	$ 30,630,195	$ 17,658,496	57.65%	$ 2,394,007	7.82%	$ 20,052,503	65.47%
North Loop Gas Unit 1								
341.00	Structures and Improvements	$ 411,070	$ 338,131	82.26%	$ 45,310	11.02%	$ 383,441	93.28%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	678,545	363,159	53.52%	49,267	7.26%	412,426	60.78%
344.00	Generators and Devices	3,582,271	3,487,302	97.35%	472,149	13.18%	3,959,451	110.53%
345.00	Accessory Electric Equipment	790,955	643,803	81.40%	87,719	11.09%	731,523	92.49%
346.00	Miscellaneous Power Plant Equipment	306,369	261,396	85.32%	35,027	11.43%	296,423	96.75%
	Total North Loop Gas Unit 1	$ 5,769,210	$ 5,093,792	88.29%	$ 689,471	11.95%	$ 5,783,263	100.24%
North Loop Gas Unit 2								
341.00	Structures and Improvements	$ 196,078	$ 176,079	89.80%	$ 31,518	16.07%	$ 207,598	105.88%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	263,450	(167,022)	-63.40%	25,032	9.50%	(141,991)	-53.90%
344.00	Generators and Devices	3,239,719	2,960,031	91.37%	541,676	16.72%	3,501,707	108.09%
345.00	Accessory Electric Equipment	504,895	396,530	78.54%	72,474	14.35%	469,004	92.89%
346.00	Miscellaneous Power Plant Equipment	128,559	126,556	98.44%	22,527	17.52%	149,084	115.97%
	Total North Loop Gas Unit 2	$ 4,332,701	$ 3,492,175	80.60%	$ 693,227	16.00%	$ 4,185,401	96.60%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
North Loop Gas Unit 3								
341.00	Structures and Improvements	$ 196,078	$ 184,523	94.11%	$ 29,708	15.15%	$ 214,232	109.26%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	948,951	358,052	37.73%	64,042	6.75%	422,094	44.48%
344.00	Generators and Devices	3,030,531	2,918,939	96.32%	488,229	16.11%	3,407,168	112.43%
345.00	Accessory Electric Equipment	503,907	414,896	82.34%	68,100	13.51%	482,997	95.85%
346.00	Miscellaneous Power Plant Equipment	128,559	132,626	103.16%	21,353	16.61%	153,978	119.77%
Total North Loop Gas Unit 3		$ 4,808,026	$ 4,009,037	83.38%	$ 671,433	13.96%	$ 4,680,469	97.35%
North Loop Gas Unit 4								
341.00	Structures and Improvements	$ 85,375	$ 25,309	29.64%	$ 7,214	8.45%	$ 32,523	38.09%
342.00	Fuel Holders, Products and Accessories	303,037	98,389	32.47%	5,608	1.85%	103,998	34.32%
343.00	Prime Movers							
344.00	Generators and Devices	14,209,666	4,603,085	32.39%	295,922	2.08%	4,899,007	34.48%
345.00	Accessory Electric Equipment	1,029,414	306,590	29.78%	27,519	2.67%	334,109	32.46%
346.00	Miscellaneous Power Plant Equipment	92,766	30,119	32.47%	3,613	3.89%	33,732	36.36%
Total North Loop Gas Unit 4		$ 15,720,258	$ 5,063,493	32.21%	$ 339,876	2.16%	$ 5,403,369	34.37%
Solar Units (Generators and Devices)								
344.00	DeMoss Petrie	$ 1,146,081	$ 581,895	50.77%	$ 29,095	2.54%	$ 610,990	53.31%
344.00	Fort Huachuca	36,709,538	786,429	2.14%	39,321	0.11%	825,751	2.25%
344.00	HQ Rooftop	303,184	32,476	10.71%	1,624	0.54%	34,099	11.25%
344.00	OH Rooftop	2,594,590	389,088	15.00%	19,454	0.75%	408,542	15.75%
344.00	OH Test Yard	388,459	185,913	47.86%	9,296	2.39%	195,208	50.25%
344.00	Prairie Fire	19,036,520	2,039,099	10.71%	101,955	0.54%	2,141,054	11.25%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	14,654,846	50.94%	732,742	2.55%	15,387,588	53.49%
344.00	Springerville Site 4	7,873,874	1,518,140	19.28%	75,907	0.96%	1,594,047	20.24%
344.00	Tucson	87,198	60,450	69.32%	3,022	3.47%	63,472	72.79%
344.00	U of A Tech Park Site 1	7,723,832	1,489,211	19.28%	74,461	0.96%	1,563,671	20.24%
344.00	U of A Tech Park Site 2	19,191,952	2,878,048	15.00%	143,902	0.75%	3,021,950	15.75%
344.00	White Mountain	46,499,099	996,151	2.14%	49,808	0.11%	1,045,959	2.25%
Total Solar Units		$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Sundt Gas								
341.00	Structures and Improvements	$ 11,090	$ 11,262	101.55%	$ 259	2.33%	$ 11,521	103.89%
342.00	Fuel Holders, Products and Accessories	788,336	435,849	55.29%	9,372	1.19%	445,221	56.48%
343.00	Prime Movers	141,618	110,355	77.92%	2,373	1.68%	112,728	79.60%
344.00	Generators and Devices	8,382,044	8,760,751	104.52%	196,023	2.34%	8,956,775	106.86%
345.00	Accessory Electric Equipment	1,078,811	1,056,365	97.92%	23,307	2.16%	1,079,672	100.08%
346.00	Miscellaneous Power Plant Equipment	49,750	57,384	115.35%	1,240	2.49%	58,624	117.84%
Total Sundt Gas		$ 10,451,649	$ 10,431,966	99.81%	$ 232,574	2.23%	$ 10,664,539	102.04%
Sundt Gas Unit 1								
341.00	Structures and Improvements	$ 5,545	$ 5,596	100.92%	$ 126	2.27%	$ 5,722	103.19%
342.00	Fuel Holders, Products and Accessories	394,168	216,571	54.94%	4,548	1.15%	221,118	56.10%
343.00	Prime Movers	70,809	54,835	77.44%	1,152	1.63%	55,986	79.07%
344.00	Generators and Devices	4,315,668	4,524,215	104.83%	96,969	2.25%	4,621,184	107.08%
345.00	Accessory Electric Equipment	516,231	508,210	98.45%	10,940	2.12%	519,149	100.57%
346.00	Miscellaneous Power Plant Equipment	19,906	22,861	114.85%	480	2.41%	23,341	117.26%
Total Sundt Gas Unit 1		$ 5,322,327	$ 5,332,287	100.19%	$ 114,214	2.15%	$ 5,446,501	102.33%
Sundt Gas Unit 2								
341.00	Structures and Improvements	$ 5,545	$ 5,666	102.19%	$ 133	2.40%	$ 5,799	104.58%
342.00	Fuel Holders, Products and Accessories	394,168	219,278	55.63%	4,824	1.22%	224,102	56.85%
343.00	Prime Movers	70,809	55,520	78.41%	1,221	1.72%	56,742	80.13%
344.00	Generators and Devices	4,066,376	4,236,536	104.18%	99,054	2.44%	4,335,590	106.62%
345.00	Accessory Electric Equipment	562,580	548,155	97.44%	12,367	2.20%	560,522	99.63%
346.00	Miscellaneous Power Plant Equipment	29,844	34,523	115.68%	760	2.54%	35,283	118.22%
Total Sundt Gas Unit 2		$ 5,129,322	$ 5,099,679	99.42%	$ 118,359	2.31%	$ 5,218,038	101.73%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION									
310.00 Rights-of-Way	$ 6,273,568	$ 1,166,906	$ 5,106,662		0.0%	$ -	$ (734)	$ (734)	
311.00 Structures and Improvements	241,715,429	36,437,740	205,277,689	-0.7%	-19.5%	(254,013)	(40,030,339)	(40,284,352)	-16.7%
312.00 Boiler Plant Equipment	1,269,797,647	177,844,486	1,091,953,161	-5.3%	-18.2%	(9,352,892)	(198,749,235)	(208,102,126)	-16.4%
314.00 Turbogenerator Units	364,977,004	61,935,081	303,041,923	-3.6%	-15.4%	(2,209,759)	(46,699,803)	(48,909,562)	-13.4%
315.00 Accessory Electric Equipment	151,813,441	7,231,970	144,581,471	-0.8%	-19.4%	(54,707)	(28,114,543)	(28,169,250)	-18.6%
316.00 Miscellaneous Power Plant Equipment	27,947,025	2,724,162	25,222,863	-0.1%	-12.1%	(1,619)	(3,041,590)	(3,043,208)	-10.9%
Total Steam Production Plant	$ 2,062,524,114	$ 287,340,345	$ 1,775,183,769	-4.1%	-17.8%	$ (11,872,989)	$ (316,636,243)	$ (328,509,232)	-15.9%
OTHER PRODUCTION									
Non-Solar									
341.00 Structures and Improvements	$ 23,624,549	$ 221,088	$ 23,403,461	3.3%	-14.5%	$ 7,192	$ (3,397,000)	$ (3,389,808)	-14.3%
342.00 Fuel Holders, Products and Accessories	19,985,288	8,101	19,977,187		-14.0%		(2,805,602)	(2,805,602)	-14.0%
343.00 Prime Movers	205,281,935	3,276,801	202,005,134		-8.9%		(18,070,205)	(18,070,205)	-8.8%
344.00 Generators and Devices	115,467,853	9,980,628	105,487,225	-0.4%	-9.3%	(43,629)	(9,811,971)	(9,855,600)	-8.5%
345.00 Accessory Electric Equipment	15,595,403	1,785,584	13,809,819		-8.6%	(318)	(1,190,453)	(1,190,771)	-7.6%
346.00 Miscellaneous Power Plant Equipment	15,414,670	107,510	15,307,160		-13.7%		(2,091,776)	(2,091,776)	-13.6%
Total Non-Solar	$ 395,369,698	$ 15,379,712	$ 379,989,986	-0.2%	-9.8%	$ (36,755)	$ (37,367,008)	$ (37,403,763)	-9.5%
Solar									
344.00 Generators and Devices	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
Total Solar	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
Total Other Production Plant	$ 565,690,630	$ 15,379,712	$ 550,310,918	-0.2%	-8.3%	$ (36,755)	$ (45,883,055)	$ (45,919,810)	-8.1%
DISTRIBUTION PLANT									
360.RW Rights-of-Way	$ 7,882,488	$ 17,415	$ 7,865,073			$ -	$ -	$ -	
361.00 Structures and Improvements	12,185,407	782,933	11,402,474						
362.00 Station Equipment	170,550,706	13,483,176	157,067,530						
364.00 Poles, Towers and Fixtures	233,941,047	11,934,080	222,006,967						
365.00 Overhead Conductors and Devices	185,805,025	10,129,059	175,675,966						
366.00 Underground Conduit	60,132,553	1,407,198	58,725,355						
367.00 Underground Conductors and Devices	304,814,478	7,631,343	297,183,135						
368.OH Line Transformers - Overhead	122,002,086	18,344,164	103,657,922						
368.UG Line Transformers - Underground	183,763,798	10,872,866	172,890,932						
369.OH Services - Overhead	20,027,424	2,485,188	17,542,236						
369.UG Services - Underground	113,190,446	242,732	112,947,714						
370.00 Meters	83,815,254	38,945,431	44,869,823						
373.00 Street Lighting and Signal Systems	12,730,933	952,571	11,778,362						
Total Distribution Plant	$ 1,510,841,645	$ 117,228,156	$ 1,393,613,489			$ -	$ -	$ -	

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$ 142,216,884	$ 6,536,536	$ 135,680,348	-25.1%	-5.0%	$ (1,640,671)	$ (6,784,017)	$ (8,424,688)	-5.9%
392.C0 Transportation - Class 0	2,693,017	1,454,071	1,238,946	18.8%	15.0%	273,365	185,842	459,207	17.1%
392.C1 Transportation - Class 1	18,234,904	10,516,721	7,718,183	18.8%	15.0%	1,977,144	1,157,727	3,134,871	17.2%
392.C2 Transportation - Class 2	11,814,454	7,974,547	3,839,907	18.8%	15.0%	1,499,215	575,986	2,075,201	17.6%
392.C3 Transportation - Class 3	9,677,240	7,600,304	2,076,936	18.8%	15.0%	1,428,857	311,540	1,740,398	18.0%
392.C4 Transportation - Class 4	14,756,225	11,821,198	2,935,027	18.8%	15.0%	2,222,385	440,254	2,662,639	18.0%
392.C5 Transportation - Class 5	15,016,948	7,034,233	7,982,715	18.8%	15.0%	1,322,436	1,197,407	2,519,843	16.8%
392.C6 Transportation - Class 6	365,200		365,200	18.8%	15.0%		54,780	54,780	15.0%
392.C7 Transportation - Class 7	1,047,216		1,047,216	18.8%	15.0%		157,082	157,082	15.0%
392.C8 Transportation - Class 8	10,369,813	412,313	9,957,500	18.8%	15.0%	77,515	1,493,625	1,571,140	15.2%
392.C9 Transportation - Class 9	4,607,987	355,701	4,252,286	18.8%	15.0%	66,872	637,843	704,715	15.3%
396.00 Power Operatied Equipment	20,256,159	8,395,219	11,860,940	2.3%		193,090		193,090	1.0%
397.EM EMS and SCADA Equipment	11,481,719	177,348	11,304,371						
Total Depreciable	$ 262,537,766	$ 62,278,191	$ 200,259,575	11.9%	-0.3%	$ 7,420,208	$ (571,930)	$ 6,848,278	2.6%
Amortizable									
391.00 Furniture and Office Equipment	$ 29,004,709	$ 5,040,298	$ 23,964,411			$ -	$ -	$ -	
391.20 Network and Data Equipment	87,362,414	58,002,778	29,359,636						
393.00 Stores Equipment	4,720,343	2,867,864	1,852,479						
394.00 Tools, Shop and Garage Equipment	13,766,165	6,831,797	6,934,368						
395.00 Laboratory Equipment	8,948,263	3,856,993	5,091,270						
397.20 Telecommunications Equipment	84,671,141	27,215,000	57,456,141						
398.00 Miscellaneous Equipment	6,295,272	1,947,063	4,348,209						
Total Amortizable	$ 234,768,307	$ 105,761,793	$ 129,006,514			$ -	$ -	$ -	
Total General Plant	$ 497,306,073	$ 168,039,984	$ 329,266,089	4.4%	-0.2%	$ 7,420,208	$ (571,930)	$ 6,848,278	1.4%
SUBTOTAL	$ 4,636,362,462	$ 587,988,197	$ 4,048,374,265	-0.8%	-9.0%	$ (4,489,536)	$ (363,091,228)	$ (367,580,764)	-7.9%
NET SALVAGE									
108.02 Distribution	$ 1,511,081,011	$ 117,467,522	$ 1,393,613,489	-2.9%	-15.0%	$ (3,406,558)	$ (209,042,023)	$ (212,448,581)	-14.1%
Total Net Salvage	$ 1,511,081,011	$ 117,467,522	$ 1,393,613,489	-2.9%	-15.0%	$ (3,406,558)	$ (209,042,023)	$ (212,448,581)	-14.1%
TOTAL UTILITY	$ 6,147,443,473	$ 705,455,719	$ 5,441,987,754	-1.1%	-10.5%	$ (7,896,094)	$ (572,133,252)	$ (580,029,346)	-9.4%
STEAM PRODUCTION (by Unit)									
Four Corners									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,073,950	91,173	2,982,777		-6.3%		(189,175)	(189,175)	-6.2%
312.00 Boiler Plant Equipment	83,264,815	6,862,754	76,402,061	-12.4%	-6.3%	(851,462)	(4,841,671)	(5,693,133)	-6.8%
314.00 Turbogenerator Units	13,995,637	1,636,157	12,359,480		-6.3%		(777,830)	(777,830)	-5.6%
315.00 Accessory Electric Equipment	5,176,981	786,001	4,390,980		-6.3%		(278,272)	(278,272)	-5.4%
316.00 Miscellaneous Power Plant Equipment	4,006,877	174,643	3,832,234		-6.1%		(233,688)	(233,688)	-5.8%
Total Four Corners	$ 109,518,260	$ 9,550,728	$ 99,967,532	-8.9%	-6.3%	$ (851,462)	$ (6,320,636)	$ (7,172,098)	-6.5%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description		Plant Investment			Salvage Rate		Net Salvage			Average
		Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Four Corners Unit 4										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,568,186	43,772	1,524,414		-6.0%		(91,465)	(91,465)	-5.8%
312.00	Boiler Plant Equipment	43,976,009	4,366,471	39,609,538	-19.5%	-6.0%	(851,462)	(2,376,572)	(3,228,034)	-7.3%
314.00	Turbogenerator Units	8,391,807	1,212,445	7,179,362		-6.0%		(430,762)	(430,762)	-5.1%
315.00	Accessory Electric Equipment	2,867,113	592,277	2,274,836		-6.0%		(136,490)	(136,490)	-4.8%
316.00	Miscellaneous Power Plant Equipment	2,037,484	108,323	1,929,161		-5.8%		(111,891)	(111,891)	-5.5%
Total Four Corners Unit 4		$ 58,840,599	$ 6,323,288	$ 52,517,311	-13.5%	-6.0%	$ (851,462)	$ (3,147,180)	$ (3,998,642)	-6.8%
Four Corners Unit 5										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,505,764	47,401	1,458,363		-6.7%		(97,710)	(97,710)	-6.5%
312.00	Boiler Plant Equipment	39,288,806	2,496,283	36,792,523		-6.7%		(2,465,099)	(2,465,099)	-6.3%
314.00	Turbogenerator Units	5,603,830	423,712	5,180,118		-6.7%		(347,068)	(347,068)	-6.2%
315.00	Accessory Electric Equipment	2,309,868	193,724	2,116,144		-6.7%		(141,782)	(141,782)	-6.1%
316.00	Miscellaneous Power Plant Equipment	1,969,393	66,320	1,903,073		-6.4%		(121,797)	(121,797)	-6.2%
Total Four Corners Unit 5		$ 50,677,661	$ 3,227,440	$ 47,450,221		-6.7%	$ -	$ (3,173,456)	$ (3,173,456)	-6.3%
Navajo										
310.00	Rights-of-Way	$ 12,229	$ -	$ 12,229		-6.0%	$ -	$ (734)	$ (734)	-6.0%
311.00	Structures and Improvements	19,133,681	478,525	18,655,156	-0.6%	-6.0%	(2,794)	(1,118,181)	(1,120,975)	-5.9%
312.00	Boiler Plant Equipment	93,542,762	4,998,561	88,544,201	1.6%	-5.9%	78,293	(5,215,450)	(5,137,157)	-5.5%
314.00	Turbogenerator Units	21,695,188	1,439,662	20,255,526	-0.5%	-5.9%	(7,076)	(1,188,857)	(1,195,933)	-5.5%
315.00	Accessory Electric Equipment	14,944,456	114,598	14,829,858	2.9%	-5.9%	3,374	(879,329)	(875,955)	-5.9%
316.00	Miscellaneous Power Plant Equipment	4,527,877	9,280	4,518,597	-17.4%	-5.9%	(1,619)	(266,897)	(268,516)	-5.9%
Total Navajo		$ 153,856,193	$ 7,040,626	$ 146,815,567	1.0%	-5.9%	$ 70,179	$ (8,669,447)	$ (8,599,269)	-5.6%
Navajo Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,183,276	(7,287)	3,190,563		-5.0%		(159,528)	(159,528)	-5.0%
312.00	Boiler Plant Equipment	28,591,944	1,393,362	27,198,582	-4.9%	-5.0%	(68,275)	(1,359,929)	(1,428,204)	-5.0%
314.00	Turbogenerator Units	7,568,560	707,571	6,860,989	-1.0%	-5.0%	(7,076)	(343,049)	(350,125)	-4.6%
315.00	Accessory Electric Equipment	3,763,595	219,295	3,544,300	-0.6%	-5.0%	(1,316)	(177,215)	(178,531)	-4.7%
316.00	Miscellaneous Power Plant Equipment	492,993	21,766	471,227	-4.0%	-4.9%	(871)	(23,090)	(23,961)	-4.9%
Total Navajo Unit 1		$ 43,600,368	$ 2,334,707	$ 41,265,661	-3.3%	-5.0%	$ (77,537)	$ (2,062,812)	$ (2,140,349)	-4.9%
Navajo Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,882,084	79,399	1,802,685		-6.6%		(118,977)	(118,977)	-6.3%
312.00	Boiler Plant Equipment	28,261,337	1,379,051	26,882,286	4.9%	-6.6%	67,573	(1,774,231)	(1,706,657)	-6.0%
314.00	Turbogenerator Units	7,024,429	98,379	6,926,050		-6.6%		(457,119)	(457,119)	-6.5%
315.00	Accessory Electric Equipment	3,352,457	180,127	3,172,330	-0.6%	-6.6%	(1,081)	(209,374)	(210,455)	-6.3%
316.00	Miscellaneous Power Plant Equipment	539,942	24,068	515,874	-3.6%	-6.4%	(866)	(33,016)	(33,882)	-6.3%
Total Navajo Unit 2		$ 41,060,249	$ 1,761,024	$ 39,299,225	3.7%	-6.6%	$ 65,626	$ (2,592,717)	$ (2,527,091)	-6.2%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Navajo Unit 3									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,738,690	57,179	3,681,511		-6.0%		(220,891)	(220,891)	-5.9%
312.00 Boiler Plant Equipment	29,815,550	2,097,036	27,718,514	5.3%	-6.0%	111,143	(1,663,111)	(1,551,968)	-5.2%
314.00 Turbogenerator Units	6,805,747	626,803	6,178,944		-6.0%		(370,737)	(370,737)	-5.4%
315.00 Accessory Electric Equipment	4,794,821	(345,051)	5,139,872	0.3%	-6.0%	(1,035)	(308,392)	(309,427)	-6.5%
316.00 Miscellaneous Power Plant Equipment	455,762	(93,600)	549,362	0.3%	-5.8%	(281)	(31,863)	(32,144)	-7.1%
Total Navajo Unit 3	$ 45,610,570	$ 2,342,367	$ 43,268,203	4.7%	-6.0%	$ 109,827	$ (2,594,993)	$ (2,485,167)	-5.4%
Navajo Common									
310.00 Rights-of-Way	$ 12,229	$ -	$ 12,229		-6.0%	$ -	$ (734)	$ (734)	-6.0%
311.00 Structures and Improvements	10,329,631	349,234	9,980,397	-0.8%	-6.2%	(2,794)	(618,785)	(621,578)	-6.0%
312.00 Boiler Plant Equipment	6,873,931	129,112	6,744,819	-24.9%	-6.2%	(32,149)	(418,179)	(450,328)	-6.6%
314.00 Turbogenerator Units	296,452	6,909	289,543		-6.2%		(17,952)	(17,952)	-6.1%
315.00 Accessory Electric Equipment	3,033,583	60,227	2,973,356	11.3%	-6.2%	6,806	(184,348)	(177,542)	-5.9%
316.00 Miscellaneous Power Plant Equipment	3,039,180	57,046	2,982,134	0.7%	-6.0%	399	(178,928)	(178,529)	-5.9%
Total Navajo Common	$ 23,585,006	$ 602,528	$ 22,982,478	-4.6%	-6.2%	$ (27,738)	$ (1,418,925)	$ (1,446,663)	-6.1%
San Juan									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	15,360,481	922,737	14,437,744		-9.6%		(1,384,374)	(1,384,374)	-9.0%
312.00 Boiler Plant Equipment	179,068,616	24,561,708	154,506,908	-10.9%	-11.7%	(2,682,943)	(18,152,345)	(20,835,287)	-11.6%
314.00 Turbogenerator Units	47,886,955	3,591,282	44,295,673		-9.7%		(4,296,680)	(4,296,680)	-9.0%
315.00 Accessory Electric Equipment	10,694,978	631,452	10,063,526		-9.7%		(976,162)	(976,162)	-9.1%
316.00 Miscellaneous Power Plant Equipment	2,285,721	276,166	2,009,555		-9.3%		(186,216)	(186,216)	-8.1%
Total San Juan	$ 255,296,751	$ 29,983,345	$ 225,313,406	-8.9%	-11.1%	$ (2,682,943)	$ (24,995,777)	$ (27,678,720)	-10.8%
San Juan Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	15,191,141	922,737	14,268,404		-9.7%		(1,384,035)	(1,384,035)	-9.1%
312.00 Boiler Plant Equipment	170,696,078	24,243,049	146,453,029	-12.1%	-9.7%	(2,933,409)	(14,205,944)	(17,139,353)	-10.0%
314.00 Turbogenerator Units	47,886,955	3,591,282	44,295,673		-9.7%		(4,296,680)	(4,296,680)	-9.0%
315.00 Accessory Electric Equipment	10,694,978	631,452	10,063,526		-9.7%		(976,162)	(976,162)	-9.1%
316.00 Miscellaneous Power Plant Equipment	2,236,338	276,166	1,960,172		-9.5%		(186,216)	(186,216)	-8.3%
Total San Juan Unit 1	$ 246,705,490	$ 29,664,686	$ 217,040,804	-9.9%	-9.7%	$ (2,933,409)	$ (21,049,038)	$ (23,982,447)	-9.7%
San Juan Common									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	169,340		169,340		-0.2%		(339)	(339)	-0.2%
312.00 Boiler Plant Equipment	8,372,538	318,659	8,053,879	78.6%	-49.0%	250,466	(3,946,401)	(3,695,935)	-44.1%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment	49,383		49,383						
Total San Juan Common	$ 8,591,261	$ 318,659	$ 8,272,602	78.6%	-47.7%	$ 250,466	$ (3,946,739)	$ (3,696,273)	-43.0%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Springerville									
310.00 Rights-of-Way	$ 6,261,339	$ 1,166,906	$ 5,094,433			$ -	$ -	$ -	
311.00 Structures and Improvements	175,350,915	33,624,274	141,726,641	-0.7%	-17.8%	(251,219)	(25,222,559)	(25,473,778)	-14.5%
312.00 Boiler Plant Equipment	772,876,714	131,189,349	641,687,365	-4.5%	-18.3%	(5,896,780)	(117,543,561)	(123,440,341)	-16.0%
314.00 Turbogenerator Units	223,365,420	49,715,505	173,649,915	-4.4%	-6.6%	(2,202,683)	(11,423,692)	(13,626,375)	-6.1%
315.00 Accessory Electric Equipment	78,903,325	3,038,707	75,864,618	-1.9%	-8.8%	(58,081)	(6,675,884)	(6,733,965)	-8.5%
316.00 Miscellaneous Power Plant Equipment	14,477,485	1,948,501	12,528,984		-9.3%		(1,168,148)	(1,168,148)	-8.1%
Total Springerville	$ 1,271,235,198	$ 220,683,242	$ 1,050,551,956	-3.8%	-15.4%	$ (8,408,763)	$ (162,033,845)	$ (170,442,608)	-13.4%
Springerville Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	26,483,850	6,407,835	20,076,015		-5.5%		(1,104,181)	(1,104,181)	-4.2%
312.00 Boiler Plant Equipment	243,028,846	57,346,356	185,682,490		-5.5%		(10,212,537)	(10,212,537)	-4.2%
314.00 Turbogenerator Units	65,088,339	15,541,027	49,547,312		-5.5%		(2,725,102)	(2,725,102)	-4.2%
315.00 Accessory Electric Equipment	22,841,460	1,627,293	21,214,167		-5.5%		(1,166,779)	(1,166,779)	-5.1%
316.00 Miscellaneous Power Plant Equipment	4,778,042	1,500,300	3,277,742		-5.1%		(167,165)	(167,165)	-3.5%
Total Springerville Unit 1	$ 362,220,537	$ 82,422,811	$ 279,797,726		-5.5%	$ -	$ (15,375,764)	$ (15,375,764)	-4.2%
Springerville Unit 1 Common									
310.00 Rights-of-Way	$ 2,310,402	$ 1,166,906	$ 1,143,496			$ -	$ -	$ -	
311.00 Structures and Improvements	74,990,847	22,498,021	52,492,826		-16.8%		(8,818,795)	(8,818,795)	-11.8%
312.00 Boiler Plant Equipment	19,321,712	4,466,913	14,854,799		-16.8%		(2,495,606)	(2,495,606)	-12.9%
314.00 Turbogenerator Units	1,551,370	287,048	1,264,322		-16.8%		(212,406)	(212,406)	-13.7%
315.00 Accessory Electric Equipment	9,774,817	147,720	9,627,097		-16.8%		(1,617,352)	(1,617,352)	-16.5%
316.00 Miscellaneous Power Plant Equipment	2,140,360	181,348	1,959,012		-16.4%		(321,278)	(321,278)	-15.0%
Total Springerville Unit 1 Common	$ 110,089,508	$ 28,747,956	$ 81,341,552		-16.6%	$ -	$ (13,465,437)	$ (13,465,437)	-12.2%
Springerville Unit 2									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	38,669,006	2,128,976	36,540,030	-11.8%	-6.7%	(251,219)	(2,448,182)	(2,699,401)	-7.0%
312.00 Boiler Plant Equipment	358,654,246	62,731,701	295,922,545	-9.4%	-6.7%	(5,896,780)	(19,826,811)	(25,723,590)	-7.2%
314.00 Turbogenerator Units	155,942,778	33,887,430	122,055,348	-6.5%	-6.7%	(2,202,683)	(8,177,708)	(10,380,391)	-6.7%
315.00 Accessory Electric Equipment	43,609,568	1,262,629	42,346,939	-4.6%	-6.7%	(58,081)	(2,837,245)	(2,895,326)	-6.6%
316.00 Miscellaneous Power Plant Equipment	6,879,594	254,925	6,624,669		-6.3%		(417,354)	(417,354)	-6.1%
Total Springerville Unit 2	$ 603,755,192	$ 100,265,661	$ 503,489,531	-8.4%	-6.7%	$ (8,408,763)	$ (33,707,300)	$ (42,116,063)	-7.0%
Springerville Unit 2 Common (Leasehold Imp.)									
310.00 Rights-of-Way	$ 2,280,838	$ -	$ 2,280,838			$ -	$ -	$ -	
311.00 Structures and Improvements	35,207,212	2,589,442	32,617,770		-39.4%		(12,851,401)	(12,851,401)	-36.5%
312.00 Boiler Plant Equipment	7,670,230	1,387,501	6,282,729		-39.4%		(2,475,395)	(2,475,395)	-32.3%
314.00 Turbogenerator Units	782,933		782,933		-39.4%		(308,476)	(308,476)	-39.4%
315.00 Accessory Electric Equipment	2,677,480	1,065	2,676,415		-39.4%		(1,054,508)	(1,054,508)	-39.4%
316.00 Miscellaneous Power Plant Equipment	679,489	11,928	667,561		-39.3%		(262,351)	(262,351)	-38.6%
Total Springerville Unit 2 Common	$ 49,298,182	$ 3,989,936	$ 45,308,246		-37.4%	$ -	$ (16,952,131)	$ (16,952,131)	-34.4%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Springerville Coal Handling									
310.00 Rights-of-Way	$ 1,670,099	$ -	$ 1,670,099			$ -	$ -	$ -	
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	144,201,680	5,256,878	138,944,802		-59.4%		(82,533,212)	(82,533,212)	-57.2%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
Total Springerville Coal Handling	$ 145,871,779	$ 5,256,878	$ 140,614,901		-58.7%	$ -	$ (82,533,212)	$ (82,533,212)	-56.6%
Sundt									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	28,796,402	1,321,031	27,475,371		-44.1%		(12,116,050)	(12,116,050)	-42.1%
312.00 Boiler Plant Equipment	141,044,740	10,232,114	130,812,626		-40.5%		(52,996,208)	(52,996,208)	-37.6%
314.00 Turbogenerator Units	58,033,804	5,552,475	52,481,329		-55.3%		(29,012,744)	(29,012,744)	-50.0%
315.00 Accessory Electric Equipment	42,093,701	2,661,212	39,432,489		-49.0%		(19,304,896)	(19,304,896)	-45.9%
316.00 Miscellaneous Power Plant Equipment	2,649,065	315,572	2,333,493		-50.9%		(1,186,640)	(1,186,640)	-44.8%
Total Sundt	$ 272,617,712	$ 20,082,404	$ 252,535,308		-45.4%	$ -	$ (114,616,538)	$ (114,616,538)	-42.0%
Sundt Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	4,268,893	342,831	3,926,062		-58.6%		(2,300,672)	(2,300,672)	-53.9%
312.00 Boiler Plant Equipment	16,399,259	2,617,078	13,782,181		-58.7%		(8,090,140)	(8,090,140)	-49.3%
314.00 Turbogenerator Units	11,467,321	1,229,814	10,237,507		-58.7%		(6,009,417)	(6,009,417)	-52.4%
315.00 Accessory Electric Equipment	7,107,197	570,882	6,536,315		-58.7%		(3,836,817)	(3,836,817)	-54.0%
316.00 Miscellaneous Power Plant Equipment	516,709	26,131	490,578		-58.6%		(287,479)	(287,479)	-55.6%
Total Sundt Unit 1	$ 39,759,379	$ 4,786,736	$ 34,972,643		-58.7%	$ -	$ (20,524,525)	$ (20,524,525)	-51.6%
Sundt Unit 2									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,151,250	338,561	2,812,689		-66.3%		(1,864,813)	(1,864,813)	-59.2%
312.00 Boiler Plant Equipment	15,058,926	687,317	14,371,609		-66.3%		(9,528,377)	(9,528,377)	-63.3%
314.00 Turbogenerator Units	9,232,349	780,426	8,451,923		-66.2%		(5,595,173)	(5,595,173)	-60.6%
315.00 Accessory Electric Equipment	6,531,575	325,875	6,205,700		-66.4%		(4,120,585)	(4,120,585)	-63.1%
316.00 Miscellaneous Power Plant Equipment	411,098	27,274	383,824		-66.2%		(254,091)	(254,091)	-61.8%
Total Sundt Unit 2	$ 34,385,198	$ 2,159,453	$ 32,225,745		-66.3%	$ -	$ (21,363,039)	$ (21,363,039)	-62.1%
Sundt Unit 3									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,083,662	321,650	2,762,012		-75.7%		(2,090,843)	(2,090,843)	-67.8%
312.00 Boiler Plant Equipment	12,808,330	827,499	11,980,831		-75.7%		(9,069,489)	(9,069,489)	-70.8%
314.00 Turbogenerator Units	16,380,197	1,549,582	14,830,615		-75.7%		(11,226,776)	(11,226,776)	-68.5%
315.00 Accessory Electric Equipment	6,922,100	781,961	6,140,139		-75.7%		(4,648,085)	(4,648,085)	-67.1%
316.00 Miscellaneous Power Plant Equipment	458,756	54,039	404,717		-75.5%		(305,561)	(305,561)	-66.6%
Total Sundt Unit 3	$ 39,653,045	$ 3,534,731	$ 36,118,314		-75.7%	$ -	$ (27,340,754)	$ (27,340,754)	-68.9%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Unit 4									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	18,292,597	317,989	17,974,608		-32.6%		(5,859,722)	(5,859,722)	-32.0%
312.00 Boiler Plant Equipment	86,676,275	6,100,220	80,576,055		-32.6%		(26,267,794)	(26,267,794)	-30.3%
314.00 Turbogenerator Units	20,953,937	1,992,653	18,961,284		-32.6%		(6,181,379)	(6,181,379)	-29.5%
315.00 Accessory Electric Equipment	21,532,829	982,494	20,550,335		-32.6%		(6,699,409)	(6,699,409)	-31.1%
316.00 Miscellaneous Power Plant Equipment	1,262,502	208,128	1,054,374		-32.2%		(339,508)	(339,508)	-26.9%
Total Sundt Unit 4	$ 148,718,140	$ 9,601,484	$ 139,116,656		-32.6%	$ -	$ (45,347,812)	$ (45,347,812)	-30.5%
Sundt Solar Booster (Areva)									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	10,101,950		10,101,950		-0.4%		(40,408)	(40,408)	-0.4%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
Total Sundt Solar Booster (Areva)	$ 10,101,950	$ -	$ 10,101,950		-0.4%	$ -	$ (40,408)	$ (40,408)	-0.4%
OTHER PRODUCTION (by Unit)									
DeMoss Petrie Gas Unit 1									
341.00 Structures and Improvements	$ 941,331	$ 179,343	$ 761,988		-9.0%	$ -	$ (68,579)	$ (68,579)	-7.3%
342.00 Fuel Holders, Products and Accessories	758,487	8,101	750,386		-9.0%		(67,535)	(67,535)	-8.9%
343.00 Prime Movers	528,037	451,271	76,766		-9.0%		(6,909)	(6,909)	-1.3%
344.00 Generators and Devices	31,682,855	909,989	30,772,866		-9.0%		(2,769,558)	(2,769,558)	-8.7%
345.00 Accessory Electric Equipment	2,300,817	1,439,325	861,492		-9.0%		(77,534)	(77,534)	-3.4%
346.00 Miscellaneous Power Plant Equipment	379,346	2,741	376,605		-9.0%		(33,894)	(33,894)	-8.9%
Total DeMoss Petrie Gas Unit 1	$ 36,590,873	$ 2,990,770	$ 33,600,103		-9.0%	$ -	$ (3,024,009)	$ (3,024,009)	-8.3%
Gila River									
341.00 Structures and Improvements	$ 8,508,950	$ -	$ 8,508,950		-8.4%	$ -	$ (713,794)	$ (713,794)	-8.4%
342.00 Fuel Holders, Products and Accessories	6,783,045		6,783,045		-8.4%		(569,597)	(569,597)	-8.4%
343.00 Prime Movers	188,744,730		188,744,730		-8.3%		(15,672,986)	(15,672,986)	-8.3%
344.00 Generators and Devices	32,783,434		32,783,434		-8.3%		(2,721,025)	(2,721,025)	-8.3%
345.00 Accessory Electric Equipment	9,030,698		9,030,698		-8.3%		(751,718)	(751,718)	-8.3%
346.00 Miscellaneous Power Plant Equipment	6,799,960		6,799,960		-8.4%		(571,061)	(571,061)	-8.4%
Total Gila River	$ 252,650,817	$ -	$ 252,650,817		-8.3%	$ -	$ (21,000,182)	$ (21,000,182)	-8.3%
Gila River Unit 3									
341.00 Structures and Improvements	$ 957,417	$ -	$ 957,417		-8.3%	$ -	$ (79,466)	$ (79,466)	-8.3%
342.00 Fuel Holders, Products and Accessories	178,424		178,424		-8.3%		(14,809)	(14,809)	-8.3%
343.00 Prime Movers	181,571,712		181,571,712		-8.3%		(15,070,452)	(15,070,452)	-8.3%
344.00 Generators and Devices	32,783,434		32,783,434		-8.3%		(2,721,025)	(2,721,025)	-8.3%
345.00 Accessory Electric Equipment	6,860,554		6,860,554		-8.3%		(569,426)	(569,426)	-8.3%
346.00 Miscellaneous Power Plant Equipment	135,558		135,558		-8.3%		(11,251)	(11,251)	-8.3%
Total Gila River Unit 3	$ 222,487,099	$ -	$ 222,487,099		-8.3%	$ -	$ (18,466,429)	$ (18,466,429)	-8.3%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Gila River Common									
341.00 Structures and Improvements	$ 7,551,533	$ -	$ 7,551,533		-8.4%	$ -	$ (634,329)	$ (634,329)	-8.4%
342.00 Fuel Holders, Products and Accessories	6,604,621		6,604,621		-8.4%		(554,788)	(554,788)	-8.4%
343.00 Prime Movers	7,173,018		7,173,018		-8.4%		(602,534)	(602,534)	-8.4%
344.00 Generators and Devices									
345.00 Accessory Electric Equipment	2,170,144		2,170,144		-8.4%		(182,292)	(182,292)	-8.4%
346.00 Miscellaneous Power Plant Equipment	6,664,402		6,664,402		-8.4%		(559,810)	(559,810)	-8.4%
Total Gila River Common	$ 30,163,718	$ -	$ 30,163,718		-8.4%	$ -	$ (2,533,752)	$ (2,533,752)	-8.4%
Luna									
341.00 Structures and Improvements	$ 13,269,836	$ 37,004	$ 13,232,832		-18.8%	$ -	$ (2,487,772)	$ (2,487,772)	-18.7%
342.00 Fuel Holders, Products and Accessories	11,352,383		11,352,383		-18.8%		(2,134,248)	(2,134,248)	-18.8%
343.00 Prime Movers	13,516,063	2,364,989	11,151,074		-18.8%		(2,096,402)	(2,096,402)	-15.5%
344.00 Generators and Devices	16,114,883	6,628,189	9,486,694		-18.8%		(1,783,498)	(1,783,498)	-11.1%
345.00 Accessory Electric Equipment	9,647		9,647		-18.8%		(1,814)	(1,814)	-18.8%
346.00 Miscellaneous Power Plant Equipment	7,449,920	25,328	7,424,592		-18.8%		(1,395,823)	(1,395,823)	-18.7%
Total Luna	$ 61,712,732	$ 9,055,510	$ 52,657,222		-18.8%	$ -	$ (9,899,558)	$ (9,899,558)	-16.0%
North Loop Gas									
341.00 Structures and Improvements	$ 891,728	$ 3,127	$ 888,601	230.0%	-14.2%	$ 7,192	$ (126,616)	$ (119,424)	-13.4%
342.00 Fuel Holders, Products and Accessories	303,037		303,037		-5.7%		(17,273)	(17,273)	-5.7%
343.00 Prime Movers	2,351,487	460,541	1,890,946		-15.4%		(290,864)	(290,864)	-12.4%
344.00 Generators and Devices	25,738,500	1,676,313	24,062,187	-2.6%	-9.8%	(43,629)	(2,357,800)	(2,401,430)	-9.3%
345.00 Accessory Electric Equipment	3,144,306	315,135	2,829,171	-0.1%	-11.9%	(318)	(336,170)	(336,488)	-10.7%
346.00 Miscellaneous Power Plant Equipment	735,694	79,441	656,253		-13.7%		(89,923)	(89,923)	-12.2%
Total North Loop Gas	$ 33,164,752	$ 2,534,557	$ 30,630,195	-1.5%	-10.5%	$ (36,755)	$ (3,218,646)	$ (3,255,401)	-9.8%
North Loop Gas Unit 1									
341.00 Structures and Improvements	$ 411,070	$ -	$ 411,070		-13.4%	$ -	$ (55,083)	$ (55,083)	-13.4%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	685,193	6,648	678,545		-13.4%		(90,925)	(90,925)	-13.3%
344.00 Generators and Devices	3,956,176	373,905	3,582,271	-10.0%	-13.4%	(37,391)	(480,024)	(517,415)	-13.1%
345.00 Accessory Electric Equipment	808,620	17,665	790,955	-0.6%	-13.4%	(106)	(105,988)	(106,094)	-13.1%
346.00 Miscellaneous Power Plant Equipment	306,369		306,369		-13.4%		(41,053)	(41,053)	-13.4%
Total North Loop Gas Unit 1	$ 6,167,428	$ 398,218	$ 5,769,210	-9.4%	-13.4%	$ (37,496)	$ (773,074)	$ (810,571)	-13.1%
North Loop Gas Unit 2									
341.00 Structures and Improvements	$ 196,078	$ -	$ 196,078		-17.9%	$ -	$ (35,098)	$ (35,098)	-17.9%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	676,560	413,110	263,450		-17.9%		(47,158)	(47,158)	-7.0%
344.00 Generators and Devices	3,441,312	201,593	3,239,719	-1.5%	-17.9%	(3,024)	(579,910)	(582,934)	-16.9%
345.00 Accessory Electric Equipment	522,560	17,665	504,895	-0.6%	-17.9%	(106)	(90,376)	(90,482)	-17.3%
346.00 Miscellaneous Power Plant Equipment	128,559		128,559		-17.8%		(22,884)	(22,884)	-17.8%
Total North Loop Gas Unit 2	$ 4,965,069	$ 632,368	$ 4,332,701	-0.5%	-17.9%	$ (3,130)	$ (775,425)	$ (778,555)	-15.7%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
North Loop Gas Unit 3									
341.00 Structures and Improvements	$ 196,078	$ -	$ 196,078		-16.1%	$ -	$ (31,569)	$ (31,569)	-16.1%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	989,734	40,783	948,951		-16.1%		(152,781)	(152,781)	-15.4%
344.00 Generators and Devices	3,387,718	357,187	3,030,531	-0.9%	-16.1%	(3,215)	(487,915)	(491,130)	-14.5%
345.00 Accessory Electric Equipment	521,572	17,665	503,907	-0.6%	-16.1%	(106)	(81,129)	(81,235)	-15.6%
346.00 Miscellaneous Power Plant Equipment	128,559		128,559		-16.1%		(20,698)	(20,698)	-16.1%
Total North Loop Gas Unit 3	$ 5,223,661	$ 415,635	$ 4,808,026	-0.8%	-16.1%	$ (3,321)	$ (774,092)	$ (777,413)	-14.9%
North Loop Gas Unit 4									
341.00 Structures and Improvements	$ 88,502	$ 3,127	$ 85,375	230.0%	-5.7%	$ 7,192	$ (4,866)	$ 2,326	2.6%
342.00 Fuel Holders, Products and Accessories	303,037		303,037		-5.7%		(17,273)	(17,273)	-5.7%
343.00 Prime Movers									
344.00 Generators and Devices	14,953,294	743,628	14,209,666		-5.7%		(809,951)	(809,951)	-5.4%
345.00 Accessory Electric Equipment	1,291,554	262,140	1,029,414		-5.7%		(58,677)	(58,677)	-4.5%
346.00 Miscellaneous Power Plant Equipment	172,207	79,441	92,766		-5.7%		(5,288)	(5,288)	-3.1%
Total North Loop Gas Unit 4	$ 16,808,594	$ 1,088,336	$ 15,720,258	0.7%	-5.7%	$ 7,192	$ (896,055)	$ (888,863)	-5.3%
Solar Units (Generators and Devices)									
344.00 DeMoss Petrie	$ 1,146,081	$ -	$ 1,146,081		-5.0%	$ -	$ (57,304)	$ (57,304)	-5.0%
344.00 Fort Huachuca	36,709,538		36,709,538		-5.0%		(1,835,477)	(1,835,477)	-5.0%
344.00 HQ Rooftop	303,184		303,184		-5.0%		(15,159)	(15,159)	-5.0%
344.00 OH Rooftop	2,594,590		2,594,590		-5.0%		(129,730)	(129,730)	-5.0%
344.00 OH Test Yard	388,459		388,459		-5.0%		(19,423)	(19,423)	-5.0%
344.00 Prairie Fire	19,036,520		19,036,520		-5.0%		(951,826)	(951,826)	-5.0%
344.00 Springerville Sites 1-3 (Legacy)	28,766,605		28,766,605		-5.0%		(1,438,330)	(1,438,330)	-5.0%
344.00 Springerville Site 4	7,873,874		7,873,874		-5.0%		(393,694)	(393,694)	-5.0%
344.00 Tucson	87,198		87,198		-5.0%		(4,360)	(4,360)	-5.0%
344.00 U of A Tech Park Site 1	7,723,832		7,723,832		-5.0%		(386,192)	(386,192)	-5.0%
344.00 U of A Tech Park Site 2	19,191,952		19,191,952		-5.0%		(959,598)	(959,598)	-5.0%
344.00 White Mountain	46,499,099		46,499,099		-5.0%		(2,324,955)	(2,324,955)	-5.0%
Total Solar Units	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
Sundt Gas									
341.00 Structures and Improvements	$ 12,704	$ 1,614	$ 11,090		-2.2%	$ -	$ (238)	$ (238)	-1.9%
342.00 Fuel Holders, Products and Accessories	788,336		788,336		-2.2%		(16,949)	(16,949)	-2.2%
343.00 Prime Movers	141,618		141,618		-2.2%		(3,045)	(3,045)	-2.2%
344.00 Generators and Devices	9,148,181	766,137	8,382,044		-2.1%		(180,089)	(180,089)	-2.0%
345.00 Accessory Electric Equipment	1,109,935	31,124	1,078,811		-2.2%		(23,218)	(23,218)	-2.1%
346.00 Miscellaneous Power Plant Equipment	49,750		49,750		-2.2%		(1,075)	(1,075)	-2.2%
Total Sundt Gas	$ 11,250,524	$ 798,875	$ 10,451,649		-2.1%	$ -	$ (224,614)	$ (224,614)	-2.0%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Gas Unit 1									
341.00 Structures and Improvements	$ 6,352	$ 807	$ 5,545		-2.1%	$ -	$ (116)	$ (116)	-1.8%
342.00 Fuel Holders, Products and Accessories	394,168		394,168		-2.1%		(8,278)	(8,278)	-2.1%
343.00 Prime Movers	70,809		70,809		-2.1%		(1,487)	(1,487)	-2.1%
344.00 Generators and Devices	4,531,439	215,771	4,315,668		-2.1%		(90,629)	(90,629)	-2.0%
345.00 Accessory Electric Equipment	531,793	15,562	516,231		-2.1%		(10,841)	(10,841)	-2.0%
346.00 Miscellaneous Power Plant Equipment	19,906		19,906		-2.1%		(418)	(418)	-2.1%
Total Sundt Gas Unit 1	$ 5,554,467	$ 232,140	$ 5,322,327		-2.1%	$ -	$ (111,769)	$ (111,769)	-2.0%
Sundt Gas Unit 2									
341.00 Structures and Improvements	$ 6,352	$ 807	$ 5,545		-2.2%	$ -	$ (122)	$ (122)	-1.9%
342.00 Fuel Holders, Products and Accessories	394,168		394,168		-2.2%		(8,672)	(8,672)	-2.2%
343.00 Prime Movers	70,809		70,809		-2.2%		(1,558)	(1,558)	-2.2%
344.00 Generators and Devices	4,616,742	550,366	4,066,376		-2.2%		(89,460)	(89,460)	-1.9%
345.00 Accessory Electric Equipment	578,142	15,562	562,580		-2.2%		(12,377)	(12,377)	-2.1%
346.00 Miscellaneous Power Plant Equipment	29,844		29,844		-2.2%		(657)	(657)	-2.2%
Total Sundt Gas Unit 2	$ 5,696,057	$ 566,735	$ 5,129,322		-2.2%	$ -	$ (112,845)	$ (112,845)	-2.0%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (by Unit)									
Four Corners									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	2,982,777	125,729	2,857,048	-5.0%	-6.4%	(6,286)	(182,685)	(188,971)	-6.3%
312.00 Boiler Plant Equipment	76,402,061	3,267,354	73,134,707	-5.0%	-6.4%	(163,368)	(4,672,872)	(4,836,239)	-6.3%
314.00 Turbogenerator Units	12,359,480	523,849	11,835,631	-5.0%	-6.3%	(26,192)	(751,424)	(777,617)	-6.3%
315.00 Accessory Electric Equipment	4,390,980	180,525	4,210,455	-5.0%	-6.4%	(9,026)	(269,033)	(278,059)	-6.3%
316.00 Miscellaneous Power Plant Equipment	3,832,234	160,207	3,672,027		-6.4%		(234,978)	(234,978)	-6.1%
Total Four Corners	$ 99,967,532	$ 4,257,665	$ 95,709,867	-4.8%	-6.4%	$ (204,873)	$ (6,110,991)	$ (6,315,864)	-6.3%
Four Corners Unit 4									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	1,524,414	64,249	1,460,165	-5.0%	-6.1%	(3,212)	(88,733)	(91,945)	-6.0%
312.00 Boiler Plant Equipment	39,609,538	1,694,925	37,914,613	-5.0%	-6.1%	(84,746)	(2,304,036)	(2,388,782)	-6.0%
314.00 Turbogenerator Units	7,179,362	303,478	6,875,884	-5.0%	-6.1%	(15,174)	(417,841)	(433,015)	-6.0%
315.00 Accessory Electric Equipment	2,274,836	93,584	2,181,252	-5.0%	-6.1%	(4,679)	(132,553)	(137,232)	-6.0%
316.00 Miscellaneous Power Plant Equipment	1,929,161	80,629	1,848,532		-6.1%		(112,334)	(112,334)	-5.8%
Total Four Corners Unit 4	$ 52,517,311	$ 2,236,864	$ 50,280,447	-4.8%	-6.1%	$ (107,812)	$ (3,055,496)	$ (3,163,307)	-6.0%
Four Corners Unit 5									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	1,458,363	61,481	1,396,882	-5.0%	-6.7%	(3,074)	(93,952)	(97,026)	-6.7%
312.00 Boiler Plant Equipment	36,792,523	1,572,430	35,220,093	-5.0%	-6.7%	(78,621)	(2,368,836)	(2,447,457)	-6.7%
314.00 Turbogenerator Units	5,180,118	220,371	4,959,747	-5.0%	-6.7%	(11,019)	(333,583)	(344,602)	-6.7%
315.00 Accessory Electric Equipment	2,116,144	86,942	2,029,202	-5.0%	-6.7%	(4,347)	(136,480)	(140,827)	-6.7%
316.00 Miscellaneous Power Plant Equipment	1,903,073	79,578	1,823,495		-6.7%		(122,645)	(122,645)	-6.4%
Total Four Corners Unit 5	$ 47,450,221	$ 2,020,801	$ 45,429,420	-4.8%	-6.7%	$ (97,061)	$ (3,055,496)	$ (3,152,557)	-6.6%
Navajo									
310.00 Rights-of-Way	$ 12,229	$ 506	$ 11,723		-6.3%	$ -	$ (737)	$ (737)	-6.0%
311.00 Structures and Improvements	18,655,156	647,268	18,007,888	-5.0%	-6.0%	(32,363)	(1,089,199)	(1,121,562)	-6.0%
312.00 Boiler Plant Equipment	88,544,201	2,742,632	85,801,569	-5.0%	-5.9%	(137,132)	(5,076,897)	(5,214,029)	-5.9%
314.00 Turbogenerator Units	20,255,526	611,609	19,643,917	-5.0%	-5.9%	(30,580)	(1,157,213)	(1,187,794)	-5.9%
315.00 Accessory Electric Equipment	14,829,858	486,654	14,343,204	-5.0%	-6.0%	(24,333)	(855,914)	(880,246)	-5.9%
316.00 Miscellaneous Power Plant Equipment	4,518,597	164,224	4,354,373		-6.2%		(268,361)	(268,361)	-5.9%
Total Navajo	$ 146,815,567	$ 4,652,894	$ 142,162,673	-4.8%	-5.9%	$ (224,408)	$ (8,448,321)	$ (8,672,729)	-5.9%
Navajo Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,190,563	35,076	3,155,487	-5.0%	-5.0%	(1,754)	(156,480)	(158,234)	-5.0%
312.00 Boiler Plant Equipment	27,198,582	289,406	26,909,176	-5.0%	-5.0%	(14,470)	(1,334,421)	(1,348,891)	-5.0%
314.00 Turbogenerator Units	6,860,989	73,135	6,787,854	-5.0%	-5.0%	(3,657)	(336,608)	(340,265)	-5.0%
315.00 Accessory Electric Equipment	3,544,300	37,858	3,506,442	-5.0%	-5.0%	(1,893)	(173,884)	(175,777)	-5.0%
316.00 Miscellaneous Power Plant Equipment	471,227	5,200	466,027		-5.0%		(23,110)	(23,110)	-4.9%
Total Navajo Unit 1	$ 41,265,661	$ 440,676	$ 40,824,985	-4.9%	-5.0%	$ (21,774)	$ (2,024,503)	$ (2,046,277)	-5.0%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account Description		12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Navajo Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,802,685	73,142	1,729,543	-5.0%	-6.7%	(3,657)	(115,420)	(119,077)	-6.6%
312.00	Boiler Plant Equipment	26,882,286	1,080,667	25,801,619	-5.0%	-6.7%	(54,033)	(1,721,861)	(1,775,894)	-6.6%
314.00	Turbogenerator Units	6,926,050	277,187	6,648,863	-5.0%	-6.7%	(13,859)	(443,709)	(457,569)	-6.6%
315.00	Accessory Electric Equipment	3,172,330	127,256	3,045,074	-5.0%	-6.7%	(6,363)	(203,212)	(209,575)	-6.6%
316.00	Miscellaneous Power Plant Equipment	515,874	21,188	494,686		-6.7%		(33,013)	(33,013)	-6.4%
Total Navajo Unit 2		$ 39,299,225	$ 1,579,440	$ 37,719,785	-4.9%	-6.7%	$ (77,913)	$ (2,517,215)	$ (2,595,128)	-6.6%
Navajo Unit 3										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,681,511	150,256	3,531,255	-5.0%	-6.1%	(7,513)	(214,054)	(221,567)	-6.0%
312.00	Boiler Plant Equipment	27,718,514	1,110,320	26,608,194	-5.0%	-6.1%	(55,516)	(1,612,907)	(1,668,423)	-6.0%
314.00	Turbogenerator Units	6,178,944	250,312	5,928,632	-5.0%	-6.1%	(12,516)	(359,375)	(371,891)	-6.0%
315.00	Accessory Electric Equipment	5,139,872	208,272	4,931,600	-5.0%	-6.1%	(10,414)	(298,938)	(309,352)	-6.0%
316.00	Miscellaneous Power Plant Equipment	549,362	22,448	526,914		-6.1%		(31,940)	(31,940)	-5.8%
Total Navajo Unit 3		$ 43,268,203	$ 1,741,608	$ 41,526,595	-4.9%	-6.1%	$ (85,958)	$ (2,517,215)	$ (2,603,173)	-6.0%
Navajo Common										
310.00	Rights-of-Way	$ 12,229	$ 506	$ 11,723		-6.3%	$ -	$ (737)	$ (737)	-6.0%
311.00	Structures and Improvements	9,980,397	388,794	9,591,603	-5.0%	-6.3%	(19,440)	(603,244)	(622,684)	-6.2%
312.00	Boiler Plant Equipment	6,744,819	262,239	6,482,580	-5.0%	-6.3%	(13,112)	(407,709)	(420,821)	-6.2%
314.00	Turbogenerator Units	289,543	10,974	278,569	-5.0%	-6.3%	(549)	(17,520)	(18,069)	-6.2%
315.00	Accessory Electric Equipment	2,973,356	113,268	2,860,088	-5.0%	-6.3%	(5,663)	(179,879)	(185,543)	-6.2%
316.00	Miscellaneous Power Plant Equipment	2,982,134	115,388	2,866,746		-6.3%		(180,298)	(180,298)	-6.0%
Total Navajo Common		$ 22,982,478	$ 891,170	$ 22,091,308	-4.3%	-6.3%	$ (38,764)	$ (1,389,388)	$ (1,428,152)	-6.2%
San Juan										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	14,437,744	463,504	13,974,240	-5.0%	-9.7%	(23,175)	(1,358,633)	(1,381,809)	-9.6%
312.00	Boiler Plant Equipment	154,506,908	4,871,333	149,635,575	-5.0%	-12.0%	(243,567)	(17,890,509)	(18,134,076)	-11.7%
314.00	Turbogenerator Units	44,295,673	1,411,705	42,883,968	-5.0%	-9.8%	(70,585)	(4,218,946)	(4,289,532)	-9.7%
315.00	Accessory Electric Equipment	10,063,526	319,494	9,744,032	-5.0%	-9.8%	(15,975)	(958,623)	(974,597)	-9.7%
316.00	Miscellaneous Power Plant Equipment	2,009,555	63,827	1,945,728		-9.6%		(186,709)	(186,709)	-9.3%
Total San Juan		$ 225,313,406	$ 7,129,861	$ 218,183,545	-5.0%	-11.3%	$ (353,302)	$ (24,613,421)	$ (24,966,723)	-11.1%
San Juan Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	14,268,404	458,417	13,809,987	-5.0%	-9.8%	(22,921)	(1,358,633)	(1,381,554)	-9.7%
312.00	Boiler Plant Equipment	146,453,029	4,622,894	141,830,135	-5.0%	-9.8%	(231,145)	(13,953,320)	(14,184,465)	-9.7%
314.00	Turbogenerator Units	44,295,673	1,411,705	42,883,968	-5.0%	-9.8%	(70,585)	(4,218,946)	(4,289,532)	-9.7%
315.00	Accessory Electric Equipment	10,063,526	319,494	9,744,032	-5.0%	-9.8%	(15,975)	(958,623)	(974,597)	-9.7%
316.00	Miscellaneous Power Plant Equipment	1,960,172	62,343	1,897,829		-9.8%		(186,709)	(186,709)	-9.5%
Total San Juan Unit 1		$ 217,040,804	$ 6,874,853	$ 210,165,951	-5.0%	-9.8%	$ (340,625)	$ (20,676,232)	$ (21,016,858)	-9.7%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
San Juan Common									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	169,340	5,087	164,253	-5.0%		(254)		(254)	-0.2%
312.00 Boiler Plant Equipment	8,053,879	248,439	7,805,440	-5.0%	-50.4%	(12,422)	(3,937,189)	(3,949,611)	-49.0%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment	49,383	1,483	47,900						
Total San Juan Common	$ 8,272,602	$ 255,009	$ 8,017,593	-5.0%	-50.4%	$ (12,676)	$ (4,044,202)	$ (3,949,865)	-47.7%
Springerville									
310.00 Rights-of-Way	$ 5,094,433	$ 303,737	$ 4,790,696			$ -	$ -	$ -	
311.00 Structures and Improvements	141,726,641	9,894,361	131,832,280	-5.0%	-18.8%	(494,718)	(24,737,530)	(25,232,248)	-17.8%
312.00 Boiler Plant Equipment	641,687,365	56,287,561	585,399,804	-5.0%	-19.6%	(2,814,378)	(114,733,067)	(117,547,445)	-18.3%
314.00 Turbogenerator Units	173,649,915	15,167,291	158,482,624	-5.0%	-6.7%	(758,365)	(10,669,694)	(11,428,059)	-6.6%
315.00 Accessory Electric Equipment	75,864,618	6,485,462	69,379,156	-5.0%	-9.2%	(324,273)	(6,349,839)	(6,674,112)	-8.8%
316.00 Miscellaneous Power Plant Equipment	12,528,984	1,039,506	11,489,478		-10.1%		(1,164,365)	(1,164,365)	-9.3%
Total Springerville	$ 1,050,551,956	$ 89,177,919	$ 961,374,037	-4.9%	-16.4%	$ (4,391,734)	$ (157,654,494)	$ (162,046,228)	-15.4%
Springerville Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	20,076,015	1,594,824	18,481,191	-5.0%	-5.5%	(79,741)	(1,014,863)	(1,094,604)	-5.5%
312.00 Boiler Plant Equipment	185,682,490	14,793,478	170,889,012	-5.0%	-5.5%	(739,674)	(9,384,078)	(10,123,752)	-5.5%
314.00 Turbogenerator Units	49,547,312	3,948,245	45,599,067	-5.0%	-5.5%	(197,412)	(2,503,995)	(2,701,407)	-5.5%
315.00 Accessory Electric Equipment	21,214,167	1,711,130	19,503,037	-5.0%	-5.5%	(85,557)	(1,070,976)	(1,156,532)	-5.5%
316.00 Miscellaneous Power Plant Equipment	3,277,742	259,549	3,018,193		-5.5%		(165,739)	(165,739)	-5.1%
Total Springerville Unit 1	$ 279,797,726	$ 22,307,227	$ 257,490,499	-4.9%	-5.5%	$ (1,102,384)	$ (14,139,651)	$ (15,242,035)	-5.4%
Springerville Unit 1 Common									
310.00 Rights-of-Way	$ 1,143,496	$ 90,874	$ 1,052,622			$ -	$ -	$ -	
311.00 Structures and Improvements	52,492,826	4,192,244	48,300,582	-5.0%	-17.8%	(209,612)	(8,619,543)	(8,829,155)	-16.8%
312.00 Boiler Plant Equipment	14,854,799	1,188,740	13,666,059	-5.0%	-17.8%	(59,437)	(2,438,794)	(2,498,231)	-16.8%
314.00 Turbogenerator Units	1,264,322	101,482	1,162,840	-5.0%	-17.8%	(5,074)	(207,516)	(212,590)	-16.8%
315.00 Accessory Electric Equipment	9,627,097	778,804	8,848,293	-5.0%	-17.8%	(38,940)	(1,579,034)	(1,617,974)	-16.8%
316.00 Miscellaneous Power Plant Equipment	1,959,012	158,119	1,800,893		-17.8%		(321,381)	(321,381)	-16.4%
Total Springerville Unit 1 Common	$ 81,341,552	$ 6,510,263	$ 74,831,289	-4.8%	-17.8%	$ (313,063)	$ (13,354,115)	$ (13,479,331)	-16.6%
Springerville Unit 2									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	36,540,030	3,339,714	33,200,316	-5.0%	-6.9%	(166,986)	(2,289,215)	(2,456,200)	-6.7%
312.00 Boiler Plant Equipment	295,922,545	27,119,399	268,803,146	-5.0%	-6.9%	(1,355,970)	(18,534,404)	(19,890,374)	-6.7%
314.00 Turbogenerator Units	122,055,348	11,099,142	110,956,206	-5.0%	-6.9%	(554,957)	(7,650,607)	(8,205,564)	-6.7%
315.00 Accessory Electric Equipment	42,346,939	3,931,538	38,415,401	-5.0%	-6.9%	(196,577)	(2,648,803)	(2,845,380)	-6.7%
316.00 Miscellaneous Power Plant Equipment	6,624,669	606,145	6,018,524		-6.9%		(414,987)	(414,987)	-6.3%
Total Springerville Unit 2	$ 503,489,531	$ 46,095,938	$ 457,393,593	-4.9%	-6.9%	$ (2,274,490)	$ (31,538,015)	$ (33,812,505)	-6.7%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Springerville Unit 2 Common (Leasehold Imp.)									
310.00 Rights-of-Way	$ 2,280,838	$ 54,667	$ 2,226,171			$ -	$ -	$ -	
311.00 Structures and Improvements	32,617,770	767,579	31,850,191	-5.0%	-40.2%	(38,379)	(12,813,909)	(12,852,288)	-39.4%
312.00 Boiler Plant Equipment	6,282,729	145,696	6,137,033	-5.0%	-40.2%	(7,285)	(2,469,040)	(2,476,324)	-39.4%
314.00 Turbogenerator Units	782,933	18,422	764,511	-5.0%	-40.2%	(921)	(307,577)	(308,498)	-39.4%
315.00 Accessory Electric Equipment	2,676,415	63,990	2,612,425	-5.0%	-40.2%	(3,199)	(1,051,026)	(1,054,225)	-39.4%
316.00 Miscellaneous Power Plant Equipment	667,561	15,693	651,868		-40.2%		(262,258)	(262,258)	-39.3%
Total Springerville Unit 2 Common	$ 45,308,246	$ 1,066,047	$ 44,242,199	-4.7%	-40.2%	$ (49,784)	$ (17,799,439)	$ (16,953,594)	-37.4%
Springerville Coal Handling									
310.00 Rights-of-Way	$ 1,670,099	$ 158,196	$ 1,511,903			$ -	$ -	$ -	
311.00 Structures and Improvements					-65.1%				
312.00 Boiler Plant Equipment	138,944,802	13,040,248	125,904,554	-5.0%	-65.1%	(652,012)	(81,906,750)	(82,558,763)	-59.4%
314.00 Turbogenerator Units					-65.1%				
315.00 Accessory Electric Equipment					-65.1%				
316.00 Miscellaneous Power Plant Equipment					-65.1%				
Total Springerville Coal Handling	$ 140,614,901	$ 13,198,444	$ 127,416,457	-4.9%	-65.1%	$ (652,012)	$ (82,890,314)	$ (82,558,763)	-58.7%
Sundt									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	27,475,371	1,952,799	25,522,572	-5.0%	-47.1%	(97,640)	(12,015,852)	(12,113,492)	-44.1%
312.00 Boiler Plant Equipment	130,812,626	9,546,882	121,265,744	-5.0%	-43.3%	(477,344)	(52,478,127)	(52,955,471)	-40.5%
314.00 Turbogenerator Units	52,481,329	2,986,121	49,495,208	-5.0%	-58.3%	(149,306)	(28,870,189)	(29,019,495)	-55.3%
315.00 Accessory Electric Equipment	39,432,489	2,508,542	36,923,947	-5.0%	-52.0%	(125,427)	(19,184,918)	(19,310,345)	-49.0%
316.00 Miscellaneous Power Plant Equipment	2,333,493	139,906	2,193,587		-54.1%		(1,186,405)	(1,186,405)	-50.8%
Total Sundt	$ 252,535,308	$ 17,134,249	$ 235,401,059	-5.0%	-48.3%	$ (849,717)	$ (113,735,492)	$ (114,585,209)	-45.4%
Sundt Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,926,062	136,193	3,789,869	-5.0%	-60.6%	(6,810)	(2,295,820)	(2,302,630)	-58.6%
312.00 Boiler Plant Equipment	13,782,181	471,482	13,310,699	-5.0%	-60.6%	(23,574)	(8,063,333)	(8,086,908)	-58.7%
314.00 Turbogenerator Units	10,237,507	350,214	9,887,293	-5.0%	-60.6%	(17,511)	(5,989,508)	(6,007,019)	-58.7%
315.00 Accessory Electric Equipment	6,536,315	216,751	6,319,564	-5.0%	-60.6%	(10,838)	(3,828,255)	(3,839,093)	-58.7%
316.00 Miscellaneous Power Plant Equipment	490,578	16,412	474,166		-60.6%		(287,239)	(287,239)	-58.6%
Total Sundt Unit 1	$ 34,972,643	$ 1,191,052	$ 33,781,591	-4.9%	-60.6%	$ (58,732)	$ (20,464,157)	$ (20,522,889)	-58.7%
Sundt Unit 2									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	2,812,689	110,169	2,702,520	-5.0%	-68.8%	(5,508)	(1,859,111)	(1,864,619)	-66.3%
312.00 Boiler Plant Equipment	14,371,609	571,825	13,799,784	-5.0%	-68.8%	(28,591)	(9,493,113)	(9,521,704)	-66.3%
314.00 Turbogenerator Units	8,451,923	342,504	8,109,419	-5.0%	-68.8%	(17,125)	(5,578,611)	(5,595,737)	-66.2%
315.00 Accessory Electric Equipment	6,205,700	236,730	5,968,970	-5.0%	-68.8%	(11,837)	(4,106,159)	(4,117,995)	-66.4%
316.00 Miscellaneous Power Plant Equipment	383,824	14,718	369,106		-68.8%		(253,915)	(253,915)	-66.2%
Total Sundt Unit 2	$ 32,225,745	$ 1,275,947	$ 30,949,798	-4.9%	-68.8%	$ (63,061)	$ (21,290,908)	$ (21,353,970)	-66.3%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Sundt Unit 3									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	2,762,012	124,459	2,637,553	-5.0%	-79.0%	(6,223)	(2,084,065)	(2,090,288)	-75.7%
312.00 Boiler Plant Equipment	11,980,831	543,246	11,437,585	-5.0%	-79.0%	(27,162)	(9,037,421)	(9,064,583)	-75.7%
314.00 Turbogenerator Units	14,830,615	662,973	14,167,642	-5.0%	-79.0%	(33,149)	(11,194,579)	(11,227,728)	-75.7%
315.00 Accessory Electric Equipment	6,140,139	271,786	5,868,353	-5.0%	-79.0%	(13,589)	(4,636,886)	(4,650,475)	-75.7%
316.00 Miscellaneous Power Plant Equipment	404,717	17,752	386,965		-79.0%		(305,761)	(305,761)	-75.5%
Total Sundt Unit 3	$ 36,118,314	$ 1,620,216	$ 34,498,098	-4.9%	-79.0%	$ (80,123)	$ (27,258,712)	$ (27,338,836)	-75.7%
Sundt Unit 4									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	17,974,608	1,581,977	16,392,631	-5.0%	-35.2%	(79,099)	(5,776,856)	(5,855,955)	-32.6%
312.00 Boiler Plant Equipment	80,576,055	7,125,872	73,450,183	-5.0%	-35.2%	(356,294)	(25,884,260)	(26,240,553)	-32.6%
314.00 Turbogenerator Units	18,961,284	1,630,429	17,330,855	-5.0%	-35.2%	(81,521)	(6,107,491)	(6,189,013)	-32.6%
315.00 Accessory Electric Equipment	20,550,335	1,783,275	18,767,060	-5.0%	-35.2%	(89,164)	(6,613,618)	(6,702,782)	-32.6%
316.00 Miscellaneous Power Plant Equipment	1,054,374	91,024	963,350		-35.2%		(339,490)	(339,490)	-32.2%
Total Sundt Unit 4	$ 139,116,656	$ 12,212,578	$ 126,904,078	-5.0%	-35.2%	$ (606,078)	$ (44,721,715)	$ (45,327,792)	-32.6%
Sundt Solar Booster (Areva)									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	10,101,950	834,456	9,267,494	-5.0%		(41,723)		(41,723)	-0.4%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 834,456	$ 9,267,494	-5.0%		$ (41,723)	$ -	$ (41,723)	-0.4%
OTHER PRODUCTION (by Unit)									
DeMoss Petrie Gas Unit 1									
341.00 Structures and Improvements	$ 761,988	$ 60,324	$ 701,664		-9.8%	$ -	$ (68,785)	$ (68,785)	-9.0%
342.00 Fuel Holders, Products and Accessories	750,386	60,186	690,200		-9.8%		(67,661)	(67,661)	-9.0%
343.00 Prime Movers	76,766	6,017	70,749		-9.8%		(6,936)	(6,936)	-9.0%
344.00 Generators and Devices	30,772,866	2,467,553	28,305,313		-9.8%		(2,774,788)	(2,774,788)	-9.0%
345.00 Accessory Electric Equipment	861,492	68,973	792,519		-9.8%		(77,691)	(77,691)	-9.0%
346.00 Miscellaneous Power Plant Equipment	376,605	30,058	346,547		-9.8%		(33,972)	(33,972)	-9.0%
Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 2,693,110	$ 30,906,993		-9.8%	$ -	$ (3,029,833)	$ (3,029,833)	-9.0%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Gila River									
341.00 Structures and Improvements	$ 8,508,950	$ 722,006	$ 7,786,944		-9.1%	$ -	$ (710,156)	$ (710,156)	-8.3%
342.00 Fuel Holders, Products and Accessories	6,783,045	575,960	6,207,085		-9.1%		(566,355)	(566,355)	-8.3%
343.00 Prime Movers	188,744,730	15,990,013	172,754,717		-9.1%		(15,678,278)	(15,678,278)	-8.3%
344.00 Generators and Devices	32,783,434	2,784,699	29,998,735		-9.1%		(2,721,926)	(2,721,926)	-8.3%
345.00 Accessory Electric Equipment	9,030,698	766,677	8,264,021		-9.1%		(750,871)	(750,871)	-8.3%
346.00 Miscellaneous Power Plant Equipment	6,799,960	577,149	6,222,811		-9.1%		(567,811)	(567,811)	-8.4%
Total Gila River	$ 252,650,817	$ 21,416,503	$ 231,234,314		-9.1%	$ -	$ (20,995,398)	$ (20,995,398)	-8.3%
Gila River Unit 3									
341.00 Structures and Improvements	$ 957,417	$ 81,280	$ 876,137		-9.1%	$ -	$ (79,496)	$ (79,496)	-8.3%
342.00 Fuel Holders, Products and Accessories	178,424	15,110	163,314		-9.1%		(14,818)	(14,818)	-8.3%
343.00 Prime Movers	181,571,712	15,386,002	166,185,710		-9.1%		(15,078,810)	(15,078,810)	-8.3%
344.00 Generators and Devices	32,783,434	2,784,699	29,998,735		-9.1%		(2,721,926)	(2,721,926)	-8.3%
345.00 Accessory Electric Equipment	6,860,554	582,436	6,278,118		-9.1%		(569,643)	(569,643)	-8.3%
346.00 Miscellaneous Power Plant Equipment	135,558	11,493	124,065		-9.1%		(11,257)	(11,257)	-8.3%
Total Gila River Unit 3	$ 222,487,099	$ 18,861,018	$ 203,626,081		-9.1%	$ -	$ (18,475,950)	$ (18,475,950)	-8.3%
Gila River Common									
341.00 Structures and Improvements	$ 7,551,533	$ 640,726	$ 6,910,807		-9.1%	$ -	$ (630,660)	$ (630,660)	-8.4%
342.00 Fuel Holders, Products and Accessories	6,604,621	560,850	6,043,771		-9.1%		(551,537)	(551,537)	-8.4%
343.00 Prime Movers	7,173,018	604,011	6,569,007		-9.1%		(599,469)	(599,469)	-8.4%
344.00 Generators and Devices					-9.1%				
345.00 Accessory Electric Equipment	2,170,144	184,242	1,985,902		-9.1%		(181,228)	(181,228)	-8.4%
346.00 Miscellaneous Power Plant Equipment	6,664,402	565,656	6,098,746		-9.1%		(556,554)	(556,554)	-8.4%
Total Gila River Common	$ 30,163,718	$ 2,555,485	$ 27,608,233		-9.1%	$ -	$ (2,519,448)	$ (2,519,448)	-8.4%
Luna									
341.00 Structures and Improvements	$ 13,232,832	$ 1,216,311	$ 12,016,521		-20.7%	$ -	$ (2,487,831)	$ (2,487,831)	-18.8%
342.00 Fuel Holders, Products and Accessories	11,352,383	1,043,899	10,308,484		-20.7%		(2,134,208)	(2,134,208)	-18.8%
343.00 Prime Movers	11,151,074	1,011,828	10,139,246		-20.7%		(2,099,170)	(2,099,170)	-18.8%
344.00 Generators and Devices	9,486,694	871,757	8,614,937		-20.7%		(1,783,587)	(1,783,587)	-18.8%
345.00 Accessory Electric Equipment	9,647	869	8,778		-20.7%		(1,817)	(1,817)	-18.8%
346.00 Miscellaneous Power Plant Equipment	7,424,592	682,593	6,741,999		-20.7%		(1,395,824)	(1,395,824)	-18.8%
Total Luna	$ 52,657,222	$ 4,827,258	$ 47,829,964		-20.7%	$ -	$ (9,902,437)	$ (9,902,437)	-18.8%
North Loop Gas									
341.00 Structures and Improvements	$ 888,601	$ 32,853	$ 855,748		-14.8%	$ -	$ (126,609)	$ (126,609)	-14.2%
342.00 Fuel Holders, Products and Accessories	303,037	24,306	278,731		-6.2%		(17,384)	(17,384)	-5.7%
343.00 Prime Movers	1,890,946	57,217	1,833,729		-15.9%		(291,465)	(291,465)	-15.4%
344.00 Generators and Devices	24,062,187	1,464,066	22,598,121		-10.4%		(2,361,288)	(2,361,288)	-9.8%
345.00 Accessory Electric Equipment	2,829,171	140,177	2,688,994		-12.5%		(336,519)	(336,519)	-11.9%
346.00 Miscellaneous Power Plant Equipment	656,253	25,875	630,378		-14.3%		(90,033)	(90,033)	-13.7%
Total North Loop Gas	$ 30,630,195	$ 1,744,493	$ 28,885,702		-11.2%	$ -	$ (3,223,298)	$ (3,223,298)	-10.5%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
North Loop Gas Unit 1									
341.00 Structures and Improvements	$ 411,070	$ 13,106	$ 397,964		-13.9%	$ -	$ (55,157)	$ (55,157)	-13.4%
342.00 Fuel Holders, Products and Accessories					-13.9%				
343.00 Prime Movers	678,545	20,776	657,769		-13.9%		(91,166)	(91,166)	-13.4%
344.00 Generators and Devices	3,582,271	117,192	3,465,079		-13.9%		(480,257)	(480,257)	-13.4%
345.00 Accessory Electric Equipment	790,955	25,195	765,760		-13.9%		(106,134)	(106,134)	-13.4%
346.00 Miscellaneous Power Plant Equipment	306,369	9,806	296,563		-13.9%		(41,103)	(41,103)	-13.4%
Total North Loop Gas Unit 1	$ 5,769,210	$ 186,076	$ 5,583,134		-13.9%	$ -	$ (773,818)	$ (773,818)	-13.4%
North Loop Gas Unit 2									
341.00 Structures and Improvements	$ 196,078	$ 6,462	$ 189,616		-18.5%	$ -	$ (35,010)	$ (35,010)	-17.9%
342.00 Fuel Holders, Products and Accessories					-18.5%				
343.00 Prime Movers	263,450	7,568	255,882		-18.5%		(47,245)	(47,245)	-17.9%
344.00 Generators and Devices	3,239,719	106,945	3,132,774		-18.5%		(578,419)	(578,419)	-17.9%
345.00 Accessory Electric Equipment	504,895	16,336	488,559		-18.5%		(90,205)	(90,205)	-17.9%
346.00 Miscellaneous Power Plant Equipment	128,559	4,314	124,245		-18.5%		(22,940)	(22,940)	-17.8%
Total North Loop Gas Unit 2	$ 4,332,701	$ 141,626	$ 4,191,075		-18.5%	$ -	$ (773,818)	$ (773,818)	-17.9%
North Loop Gas Unit 3									
341.00 Structures and Improvements	$ 196,078	$ 6,462	$ 189,616		-16.6%	$ -	$ (31,542)	$ (31,542)	-16.1%
342.00 Fuel Holders, Products and Accessories					-16.6%				
343.00 Prime Movers	948,951	28,872	920,079		-16.6%		(153,054)	(153,054)	-16.1%
344.00 Generators and Devices	3,030,531	100,299	2,930,232		-16.6%		(487,441)	(487,441)	-16.1%
345.00 Accessory Electric Equipment	503,907	16,306	487,601		-16.6%		(81,112)	(81,112)	-16.1%
346.00 Miscellaneous Power Plant Equipment	128,559	4,314	124,245		-16.6%		(20,668)	(20,668)	-16.1%
Total North Loop Gas Unit 3	$ 4,808,026	$ 156,254	$ 4,651,772		-16.6%	$ -	$ (773,818)	$ (773,818)	-16.1%
North Loop Gas Unit 4									
341.00 Structures and Improvements	$ 85,375	$ 6,822	$ 78,553		-6.2%	$ -	$ (4,899)	$ (4,899)	-5.7%
342.00 Fuel Holders, Products and Accessories	303,037	24,306	278,731		-6.2%		(17,384)	(17,384)	-5.7%
343.00 Prime Movers					-6.2%				
344.00 Generators and Devices	14,209,666	1,139,629	13,070,037		-6.2%		(815,171)	(815,171)	-5.7%
345.00 Accessory Electric Equipment	1,029,414	82,340	947,074		-6.2%		(59,068)	(59,068)	-5.7%
346.00 Miscellaneous Power Plant Equipment	92,766	7,441	85,325		-6.2%		(5,322)	(5,322)	-5.7%
Total North Loop Gas Unit 4	$ 15,720,258	$ 1,260,537	$ 14,459,721		-6.2%	$ -	$ (901,845)	$ (901,845)	-5.7%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Solar Units (Generators and Devices)									
344.00 DeMoss Petrie	$ 1,146,081	$ 1,146,081	$ -	-5.0%		$ (57,304)	$ -	$ (57,304)	-5.0%
344.00 Fort Huachuca	36,709,538	36,709,538		-5.0%		(1,835,477)		(1,835,477)	-5.0%
344.00 HQ Rooftop	303,184	303,184		-5.0%		(15,159)		(15,159)	-5.0%
344.00 OH Rooftop	2,594,590	2,594,590		-5.0%		(129,730)		(129,730)	-5.0%
344.00 OH Test Yard	388,459	388,459		-5.0%		(19,423)		(19,423)	-5.0%
344.00 Prairie Fire	19,036,520	19,036,520		-5.0%		(951,826)		(951,826)	-5.0%
344.00 Springerville Sites 1-3 (Legacy)	28,766,605	28,766,605		-5.0%		(1,438,330)		(1,438,330)	-5.0%
344.00 Springerville Site 4	7,873,874	7,873,874		-5.0%		(393,694)		(393,694)	-5.0%
344.00 Tucson	87,198	87,198		-5.0%		(4,360)		(4,360)	-5.0%
344.00 U of A Tech Park Site 1	7,723,832	7,723,832		-5.0%		(386,192)		(386,192)	-5.0%
344.00 U of A Tech Park Site 2	19,191,952	19,191,952		-5.0%		(959,598)		(959,598)	-5.0%
344.00 White Mountain	46,499,099	46,499,099		-5.0%		(2,324,955)		(2,324,955)	-5.0%
Total Solar Units	$ 170,320,932	$ 170,320,932	$ -	-5.0%		$ (8,516,047)	$ -	$ (8,516,047)	-5.0%
Sundt Gas									
341.00 Structures and Improvements	$ 11,090	$ 360	$ 10,730		-2.2%	$ -	$ (237)	$ (237)	-2.1%
342.00 Fuel Holders, Products and Accessories	788,336	24,187	764,149		-2.2%		(16,851)	(16,851)	-2.1%
343.00 Prime Movers	141,618	4,397	137,221		-2.2%		(3,026)	(3,026)	-2.1%
344.00 Generators and Devices	8,382,044	274,685	8,107,359		-2.2%		(178,687)	(178,687)	-2.1%
345.00 Accessory Electric Equipment	1,078,811	35,096	1,043,715		-2.2%		(23,034)	(23,034)	-2.1%
346.00 Miscellaneous Power Plant Equipment	49,750	1,662	48,088		-2.2%		(1,064)	(1,064)	-2.1%
Total Sundt Gas	$ 10,451,649	$ 340,387	$ 10,111,262		-2.2%	$ -	$ (222,899)	$ (222,899)	-2.1%
Sundt Gas Unit 1									
341.00 Structures and Improvements	$ 5,545	$ 180	$ 5,365		-2.2%	$ -	$ (116)	$ (116)	-2.1%
342.00 Fuel Holders, Products and Accessories	394,168	12,093	382,075		-2.2%		(8,270)	(8,270)	-2.1%
343.00 Prime Movers	70,809	2,198	68,611		-2.2%		(1,485)	(1,485)	-2.1%
344.00 Generators and Devices	4,315,668	141,569	4,174,099		-2.2%		(90,352)	(90,352)	-2.1%
345.00 Accessory Electric Equipment	516,231	16,832	499,399		-2.2%		(10,810)	(10,810)	-2.1%
346.00 Miscellaneous Power Plant Equipment	19,906	666	19,240		-2.2%		(416)	(416)	-2.1%
Total Sundt Gas Unit 1	$ 5,322,327	$ 173,539	$ 5,148,788		-2.2%	$ -	$ (111,450)	$ (111,450)	-2.1%
Sundt Gas Unit 2									
341.00 Structures and Improvements	$ 5,545	$ 180	$ 5,365		-2.2%	$ -	$ (120)	$ (120)	-2.2%
342.00 Fuel Holders, Products and Accessories	394,168	12,093	382,075		-2.2%		(8,581)	(8,581)	-2.2%
343.00 Prime Movers	70,809	2,198	68,611		-2.2%		(1,541)	(1,541)	-2.2%
344.00 Generators and Devices	4,066,376	133,116	3,933,260		-2.2%		(88,335)	(88,335)	-2.2%
345.00 Accessory Electric Equipment	562,580	18,264	544,316		-2.2%		(12,225)	(12,225)	-2.2%
346.00 Miscellaneous Power Plant Equipment	29,844	996	28,848		-2.2%		(648)	(648)	-2.2%
Total Sundt Gas Unit 2	$ 5,129,322	$ 166,848	$ 4,962,474		-2.2%	$ -	$ (111,450)	$ (111,450)	-2.2%

TUCSON ELECTRIC POWER COMPANY

Statement G

Dismantlement Costs
Steam and Other Production

Unit	Capacity (MW)	Ownership Share	Shared Cost	Final Retirement	Distributed Cost	Inflation Rate	Spend Year	Trended Cost	Accrual Rate
A	B	C	D	E	F	G	H	I	J=I/E
STEAM PRODUCTION (by Unit)									
Four Corners (2009 Cost)									
4	785	7.00%		$ 50,280,447	$ 2,225,763	2.00%	2031	$ 3,055,496	6.1%
5	785	7.00%		45,429,420	2,225,763	2.00%	2031	3,055,496	6.7%
C		5.07%							
	1570		$ 4,451,526	$ 95,709,867	$ 4,451,526			$ 6,110,991	6.4%
	Allocated to Common:								
	Allocated to Units:		$ 4,451,526						
Navajo (2011 Cost)									
1	750	7.50%		$ 40,824,985	$ 1,727,894	2.00%	2019	$ 2,024,503	5.0%
2	750	7.50%		37,719,785	1,727,894	2.00%	2030	2,517,215	6.7%
3	750	7.50%		41,526,595	1,727,894	2.00%	2030	2,517,215	6.1%
C				22,091,308	953,719	2.00%	2030	1,389,388	6.3%
	2250		$ 6,137,400	$ 142,162,673	$ 6,137,400			$ 8,448,321	5.9%
	Allocated to Common:		953,719						
	Allocated to Units:		$ 5,183,681						
San Juan (2011 Cost)									
1	340	50.00%		$ 210,165,951	$ 15,670,000	2.00%	2027	$ 20,676,232	9.8%
C		50.00%		8,017,593	3,065,000	2.00%	2027	4,044,202	50.4%
	340		$ 18,735,000	$ 218,183,545	$ 18,735,000			$ 24,720,435	11.3%
	Allocated to Common:		3,065,000						
	Allocated to Units:		$ 15,670,000						
Springerville (2011 Cost)									
1	387	49.50%	$ 7,211,620	$ 257,490,499	$ 7,211,620	2.00%	2045	$ 14,139,651	5.5%
1C		49.50%	6,810,975	74,831,289	6,810,975	2.00%	2045	13,354,115	17.8%
2	390	100.00%	14,568,930	457,393,593	14,568,930	2.00%	2050	31,538,015	6.9%
2C		100.00%	13,759,545	44,242,199	13,759,545	2.00%	2024	17,799,439	40.2%
CH		49.28%	38,291,033	127,416,457	38,291,033	2.00%	2050	82,890,314	65.1%
	777		$ 80,642,103	$ 961,374,037	$ 80,642,103			$ 159,721,533	16.6%
	Allocated to Common:								
	Allocated to Units:		$ 80,642,103						
Sundt (2011 Cost)									
1	81	100.00%	$ 5,501,274	$ 33,781,591	$ 14,614,734	2.00%	2028	$ 20,464,157	60.6%
2	81	100.00%	5,501,274	30,949,798	14,614,734	2.00%	2030	21,290,908	68.8%
3	104	100.00%	6,283,406	34,498,098	17,984,639	2.00%	2032	27,258,712	79.0%
4	120	100.00%	7,992,322	126,904,078	21,493,745	2.00%	2048	44,721,715	35.2%
C			43,429,577						
	386		$ 68,707,853	$ 226,133,565	$ 68,707,853			$ 113,735,492	50.3%
	Allocated to Common:								
	Allocated to Units:		$ 68,707,853						
OTHER PRODUCTION (by Unit)									
DeMoss Petrie (2011 Cost)									
1	75	100.00%	$ 1,515,000	$ 30,906,993	$ 1,515,000	2.00%	2046	$ 3,029,833	9.8%
C									
	75		$ 1,515,000	$ 30,906,993	$ 1,515,000			$ 3,029,833	9.8%
	Allocated to Common:								
	Allocated to Units:		$ 1,515,000						
Gila River (2011 Costs)									
3	550	75.00%		$ 203,626,081	$ 8,879,744	2.00%	2048	$ 18,475,950	9.1%
C		75.00%	1,614,499	27,608,233	1,210,874	2.00%	2048	2,519,448	9.1%
	550		$ 10,090,618	$ 231,234,314	$ 10,090,618			$ 20,995,398	9.1%
	Allocated to Common:		1,210,874						
	Allocated to Units:		$ 8,879,744						

TUCSON ELECTRIC POWER COMPANY

Statement G

Dismantlement Costs
Steam and Other Production

Unit	Capacity (MW)	Ownership Share	Shared Cost	Final Retirement	Distributed Cost	Inflation Rate	Spend Year	Trended Cost	Accrual Rate
A	B	C	D	E	F	G	H	I	J=I/E
Luna (2011 Costs)									
1	555	33.33%		$ 47,829,964	$ 4,484,719	2.00%	2051	$ 9,902,437	20.7%
C									
	555		$ 4,484,719	$ 47,829,964	$ 4,484,719			$ 9,902,437	20.7%
	Allocated to Common:								
	Allocated to Units:		$ 4,484,719						
North Loop (2011 Costs)									
1	25	100.00%		$ 5,583,134	$ 563,684	2.00%	2027	$ 773,818	13.9%
2	25	100.00%		4,191,075	563,684	2.00%	2027	773,818	18.5%
3	25	100.00%		4,651,772	563,684	2.00%	2027	773,818	16.6%
4	20	100.00%		14,459,721	450,947	2.00%	2046	901,845	6.2%
C									
	95		$ 2,142,000	$ 28,885,702	$ 2,142,000			$ 3,223,298	11.2%
	Allocated to Common:								
	Allocated to Units:		$ 2,142,000						
Solar Units									
1			$ -	$ -	$ -			$ -	
C									
			$ -	$ -	$ -			$ -	
	Allocated to Common:								
	Allocated to Units:		$ -						
Sundt Gas (2011 Costs)									
1	25	100.00%	$ 81,185	$ 5,148,788	$ 81,185	2.00%	2027	$ 111,450	2.2%
2	25	100.00%	81,185	4,962,474	81,185	2.00%	2027	111,450	2.2%
C									
	50		$ 162,370	$ 10,111,262	$ 162,370			$ 222,899	2.2%
	Allocated to Common:								
	Allocated to Units:		$ 162,370						

TUCSON ELECTRIC POWER COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
310.00 Rights-of-Way									43.02	18.80		0.0
311.00 Structures and Improvements									35.83	20.41	-16.7	-19.5
312.00 Boiler Plant Equipment									39.35	23.05	-16.4	-18.2
314.00 Turbogenerator Units									37.19	23.25	-13.4	-15.4
315.00 Accessory Electric Equipment									35.88	21.47	-18.6	-19.4
316.00 Miscellaneous Power Plant Equipment									34.83	20.88	-10.9	-12.1
Total Steam Production Plant									38.17	22.58	-15.9	-17.8
OTHER PRODUCTION												
Non-Solar												
341.00 Structures and Improvements									41.75	32.67	-14.3	
342.00 Fuel Holders, Products and Accessories									40.63	31.82	-14.0	
343.00 Prime Movers									40.57	31.72	-8.8	
344.00 Generators and Devices									42.10	28.01	-8.5	
345.00 Accessory Electric Equipment									39.56	26.72	-7.6	
346.00 Miscellaneous Power Plant Equipment									42.19	32.46	-13.6	
Total Non-Solar									41.08	30.62	-9.5	-9.8
Solar												
344.00 Generators and Devices									28.00	24.49	-5.0	
Total Solar									28.00	24.49	-5.0	-5.0
Total Other Production Plant									35.89	28.19	-8.1	-8.3
DISTRIBUTION PLANT												
360.RW Rights-of-Way							60.00	R5	60.00	37.36		
361.00 Structures and Improvements	55.00	R1	55.46	47.86			55.00	R1	55.54	46.15		
362.00 Station Equipment	60.00	R2.5	59.84	45.73			55.00	R2	55.17	41.72		
364.00 Poles, Towers and Fixtures	50.00	R2.5	50.44	35.24			55.00	R2.5	55.24	41.84		
365.00 Overhead Conductors and Devices	55.00	R3	54.84	39.69			55.00	R4	54.61	38.78		
366.00 Underground Conduit	65.00	R4	64.79	45.02			65.00	R4	64.76	44.16		
367.00 Underground Conductors and Devices	47.00	R4	46.86	32.68			50.00	R4	49.83	34.36		
368.OH Line Transformers - Overhead	45.00	R2.5	45.48	29.84			50.00	R1.5	50.73	35.22		
368.UG Line Transformers - Underground	42.00	S2	42.05	29.51			45.00	R2.5	45.18	31.45		

TUCSON ELECTRIC POWER COMPANY
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	Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
	A	B	C	D	E	F	G	H	I	J	K	L	M
369.OH	Services - Overhead	45.00	S3	44.69	27.66			47.00	S3	46.63	29.69		
369.UG	Services - Underground	60.00	S3	60.04	45.69			60.00	S3	60.05	44.81		
370.00	Meters	27.00	L1	27.43	20.37			20.00	L0.5	20.39	16.46		
373.00	Street Lighting and Signal Systems	50.00	R3	49.40	34.26			50.00	R3	49.38	32.64		
	Total Distribution Plant									50.03	36.00		
	GENERAL PLANT												
	Depreciable												
390.00	Structures and Improvements	40.00	R4	39.94	34.92	-5.7	-5.0	40.00	R3	39.96	33.19	-5.9	-5.0
392.C0	Transportation - Class 0	18.00	O2	19.87	12.63	14.7	15.0	18.00	O2	20.22	12.25	17.1	15.0
392.C1	Transportation - Class 1	8.00	L2	7.92	4.99	14.6	15.0	8.00	L2	8.11	4.41	17.2	15.0
392.C2	Transportation - Class 2	8.00	L1.5	8.03	4.98	14.6	15.0	8.00	L1.5	8.15	4.51	17.6	15.0
392.C3	Transportation - Class 3	9.00	L3	9.07	4.33	14.6	15.0	9.00	L2	9.33	4.29	18.0	15.0
392.C4	Transportation - Class 4	14.00	L1.5	13.94	7.99	14.6	15.0	14.00	L1.5	13.79	7.88	18.0	15.0
392.C5	Transportation - Class 5	13.00	S2	13.38	7.21	14.7	15.0	13.00	S2	13.39	7.18	16.8	15.0
392.C6	Transportation - Class 6	15.00	L2	15.00	13.52	15.0	15.0	15.00	L2	15.02	11.50	15.0	15.0
392.C7	Transportation - Class 7	14.00	L1.5	14.15	9.74	15.0	15.0	14.00	L1.5	14.50	8.45	15.0	15.0
392.C8	Transportation - Class 8	13.00	S2	13.18	9.15	15.0	15.0	13.00	S2	13.24	8.12	15.2	15.0
392.C9	Transportation - Class 9	20.00	S2	21.00	11.54	15.0	15.0	25.00	L2	25.55	17.56	15.3	15.0
396.00	Power Operatied Equipment	15.00	L2	15.22	10.00	3.7	5.0	15.00	L2	15.13	11.85	1.0	
397.EM	EMS and SCADA Equipment	20.00	S3	20.01	15.57			20.00	S3	20.02	14.15		
	Total Depreciable									24.20	18.60	2.6	-0.3
	Amortizable												
391.00	Furniture and Office Equipment	24.00	SQ	24.00	17.60			24.00	SQ	24.00	16.29		
391.20	Network and Data Equipment	5.00	SQ	5.00	2.76			5.00	SQ	5.00	2.46		
393.00	Stores Equipment	15.00	SQ	15.00	9.74			15.00	SQ	15.00	8.20		
394.00	Tools, Shop and Garage Equipment	17.00	SQ	17.00	9.39			17.00	SQ	17.00	9.99		
395.00	Laboratory Equipment	17.00	SQ	17.00	9.19			17.00	SQ	17.00	9.00		
397.20	Telecommunications Equipment	15.00	SQ	15.00	9.12			15.00	SQ	15.00	9.87		
398.00	Miscellaneous Equipment	20.00	SQ	20.00	10.60			20.00	SQ	20.00	11.65		
	Total Amortizable									10.98	6.71		
	Total General Plant									16.44	11.62	1.4	-0.2
	SUBTOTAL									36.90	24.77	-7.9	-9.0

TUCSON ELECTRIC POWER COMPANY
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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
NET SALVAGE												
108.02 Distribution			48.80	34.76	-14.8	-15.0			50.03	36.00	-14.1	-15.0
Total Net Salvage									50.03	36.00	-14.1	-9.8
TOTAL UTILITY									29.43	27.04	-9.4	-10.5
STEAM PRODUCTION (by Unit)												
Four Corners												
310.00 Rights-of-Way												
311.00 Structures and Improvements			31.54	17.56	-7.9	-8.0			28.98	16.15	-6.2	-6.3
312.00 Boiler Plant Equipment			36.50	17.55	-8.4	-8.0			35.84	16.14	-6.8	-6.3
314.00 Turbogenerator Units			30.52	17.47	-7.0	-7.9			31.67	16.14	-5.6	-6.3
315.00 Accessory Electric Equipment			24.13	17.46	-6.4	-7.9			21.71	16.15	-5.4	-6.3
316.00 Miscellaneous Power Plant Equipment			30.17	17.57	-7.5	-7.8			30.04	16.15	-5.8	-6.1
Total Four Corners									33.83	16.14	-6.5	-6.3
Four Corners Unit 4												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2029	200-SC	30.90	17.10	-7.5	-7.5	2031	200-SC	28.98	16.15	-5.8	-6.0
312.00 Boiler Plant Equipment	2029	200-SC	35.85	17.10	-8.8	-7.5	2031	200-SC	35.79	16.14	-7.3	-6.0
314.00 Turbogenerator Units	2029	200-SC	28.99	17.10	-6.4	-7.5	2031	200-SC	30.68	16.14	-5.1	-6.0
315.00 Accessory Electric Equipment	2029	200-SC	22.43	17.11	-5.6	-7.5	2031	200-SC	21.93	16.15	-4.8	-6.0
316.00 Miscellaneous Power Plant Equipment	2029	200-SC	29.57	17.10	-6.9	-7.3	2031	200-SC	29.95	16.15	-5.5	-5.8
Total Four Corners Unit 4									33.63	16.14	-6.8	-6.0
Four Corners Unit 5												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2030	200-SC	32.23	18.06	-8.5	-8.5	2031	200-SC	28.97	16.15	-6.5	-6.7
312.00 Boiler Plant Equipment	2030	200-SC	37.23	18.05	-8.0	-8.5	2031	200-SC	35.90	16.14	-6.3	-6.7
314.00 Turbogenerator Units	2030	200-SC	32.97	18.05	-7.9	-8.5	2031	200-SC	33.16	16.14	-6.2	-6.7
315.00 Accessory Electric Equipment	2030	200-SC	26.99	18.06	-7.7	-8.5	2031	200-SC	21.47	16.15	-6.1	-6.7
316.00 Miscellaneous Power Plant Equipment	2030	200-SC	30.81	18.06	-8.1	-8.3	2031	200-SC	30.14	16.15	-6.2	-6.4
Total Four Corners Unit 5									34.06	16.14	-6.3	-6.7

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	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Navajo												
310.00 Rights-of-Way			56.14	23.68	-7.0	-7.0			51.25	15.17	-6.0	-6.0
311.00 Structures and Improvements			41.75	23.36	-7.2	-7.2			32.54	13.56	-5.9	-6.0
312.00 Boiler Plant Equipment			39.61	22.84	-6.7	-7.2			28.93	10.66	-5.5	-5.9
314.00 Turbogenerator Units			41.38	22.72	-6.8	-7.2			29.14	10.12	-5.5	-5.9
315.00 Accessory Electric Equipment			37.59	23.16	-7.1	-7.2			23.29	10.77	-5.9	-5.9
316.00 Miscellaneous Power Plant Equipment			40.69	23.43	-7.0	-6.9			29.26	14.34	-5.9	-5.9
Total Navajo									28.67	11.04	-5.6	-5.9
Navajo Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2034	200-SC	52.47	21.81	-7.2	-7.1	2019	200-SC	36.65	4.47	-5.0	-5.0
312.00 Boiler Plant Equipment	2034	200-SC	37.97	21.84	-7.0	-7.1	2019	200-SC	21.07	4.47	-5.0	-5.0
314.00 Turbogenerator Units	2034	200-SC	39.73	21.84	-6.5	-7.1	2019	200-SC	20.90	4.47	-4.6	-5.0
315.00 Accessory Electric Equipment	2034	200-SC	40.48	21.83	-6.7	-7.1	2019	200-SC	13.49	4.47	-4.7	-5.0
316.00 Miscellaneous Power Plant Equipment	2034	200-SC	52.74	21.81	-6.7	-6.8	2019	200-SC	38.45	4.47	-4.9	-4.9
Total Navajo Unit 1									20.83	4.47	-4.9	-5.0
Navajo Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2035	200-SC	48.57	22.76	-7.4	-7.5	2030	200-SC	39.37	15.18	-6.3	-6.6
312.00 Boiler Plant Equipment	2035	200-SC	41.28	22.77	-6.9	-7.5	2030	200-SC	36.22	15.18	-6.0	-6.6
314.00 Turbogenerator Units	2035	200-SC	40.38	22.78	-7.4	-7.5	2030	200-SC	35.06	15.18	-6.5	-6.6
315.00 Accessory Electric Equipment	2035	200-SC	40.14	22.78	-7.2	-7.5	2030	200-SC	32.96	15.18	-6.3	-6.6
316.00 Miscellaneous Power Plant Equipment	2035	200-SC	50.34	22.75	-7.0	-7.2	2030	200-SC	45.75	15.17	-6.3	-6.4
Total Navajo Unit 2									35.95	15.18	-6.2	-6.6
Navajo Unit 3												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2036	200-SC	49.65	23.69	-6.9	-7.0	2030	200-SC	44.24	15.18	-5.9	-6.0
312.00 Boiler Plant Equipment	2036	200-SC	41.42	23.71	-6.1	-7.0	2030	200-SC	35.40	15.18	-5.2	-6.0
314.00 Turbogenerator Units	2036	200-SC	46.13	23.70	-6.4	-7.0	2030	200-SC	40.09	15.18	-5.4	-6.0
315.00 Accessory Electric Equipment	2036	200-SC	44.62	23.70	-7.5	-7.0	2030	200-SC	38.19	15.18	-6.5	-6.0
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	54.62	23.69	-8.1	-6.6	2030	200-SC	46.90	15.18	-7.1	-5.8
Total Navajo Unit 3									37.09	15.18	-5.4	-6.0

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Account Description	Current Parameters						Proposed Parameters (at December 31, 2014)					
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A	B	C	D	E	F	G	H	I	J	K	L	M
Navajo Common												
310.00 Rights-of-Way	2036	200-SC	56.14	23.68	-7.0	-7.0	2030	200-SC	51.25	15.17	-6.0	-6.0
311.00 Structures and Improvements	2036	200-SC	35.95	23.72	-7.3	-7.3	2030	200-SC	27.94	15.19	-6.0	-6.2
312.00 Boiler Plant Equipment	2036	200-SC	33.84	23.73	-7.6	-7.3	2030	200-SC	27.58	15.19	-6.6	-6.2
314.00 Turbogenerator Units	2036	200-SC	25.06	23.75	-7.3	-7.3	2030	200-SC	19.12	15.20	-6.1	-6.2
315.00 Accessory Electric Equipment	2036	200-SC	26.57	23.74	-7.0	-7.3	2030	200-SC	20.77	15.20	-5.9	-6.2
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	35.23	23.73	-6.9	-7.0	2030	200-SC	25.02	15.19	-5.9	-6.0
Total Navajo Common									26.13	15.19	-6.1	-6.2
San Juan												
310.00 Rights-of-Way												
311.00 Structures and Improvements			43.50	22.50	-9.7	-9.6			28.84	12.30	-9.0	-9.6
312.00 Boiler Plant Equipment			33.25	22.30	-14.3	-15.1			25.11	12.30	-11.6	-11.7
314.00 Turbogenerator Units			35.64	22.18	-8.9	-9.6			28.61	12.30	-9.0	-9.7
315.00 Accessory Electric Equipment			37.69	22.02	-9.3	-9.5			25.55	12.30	-9.1	-9.7
316.00 Miscellaneous Power Plant Equipment			47.93	21.62	-8.7	-9.1			26.25	12.30	-8.1	-9.3
Total San Juan									25.98	12.30	-10.8	-11.1
San Juan Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2036	200-SC	43.21	23.71	-9.4	-9.9	2027	200-SC	29.28	12.30	-9.1	-9.7
312.00 Boiler Plant Equipment	2036	200-SC	35.47	23.72	-10.2	-9.9	2027	200-SC	25.40	12.30	-10.0	-9.7
314.00 Turbogenerator Units	2036	200-SC	38.79	23.72	-9.2	-9.9	2027	200-SC	28.61	12.30	-9.0	-9.7
315.00 Accessory Electric Equipment	2036	200-SC	38.47	23.72	-9.4	-9.9	2027	200-SC	25.55	12.30	-9.1	-9.7
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	45.09	23.70	-8.5	-9.6	2027	200-SC	26.97	12.30	-8.3	-9.5
Total San Juan Unit 1									26.25	12.30	-9.7	-9.7
San Juan Common												
310.00 Rights-of-Way												
311.00 Structures and Improvements			43.50	22.50	-9.7	-9.6	2027	200-SC	12.79	12.30	-0.2	-0.2
312.00 Boiler Plant Equipment	2036	200-SC	33.17	23.73	-247.3	-263.1	2027	200-SC	20.75	12.30	-44.1	-49.0
314.00 Turbogenerator Units			35.64	22.18	-8.9	-9.6						
315.00 Accessory Electric Equipment			37.69	22.02	-9.3	-9.5						
316.00 Miscellaneous Power Plant Equipment			47.93	21.62	-8.7	-9.1	2027	200-SC	12.79	12.30		
Total San Juan Common									20.41	12.30	-43.0	-47.7

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A	B	C	D	E	F	G	H	I	J	K	L	M
Springerville												
310.00 Rights-of-Way									43.00	18.81		
311.00 Structures and Improvements									37.20	22.18	-14.5	-17.8
312.00 Boiler Plant Equipment									48.69	31.72	-16.0	-18.3
314.00 Turbogenerator Units									45.66	32.41	-6.1	-6.6
315.00 Accessory Electric Equipment									53.00	30.58	-8.5	-8.8
316.00 Miscellaneous Power Plant Equipment									44.94	29.44	-8.1	-9.3
Total Springerville									46.44	30.06	-13.4	-15.4
Springerville Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2021	200-SC	11.16	9.39	-0.1	-0.1	2045	200-SC	46.47	29.28	-4.2	-5.5
312.00 Boiler Plant Equipment	2021	200-SC	12.80	9.39	-0.3	-0.1	2045	200-SC	48.19	29.27	-4.2	-5.5
314.00 Turbogenerator Units	2021	200-SC	13.20	9.39	0.4	-0.1	2045	200-SC	48.45	29.27	-4.2	-5.5
315.00 Accessory Electric Equipment	2021	200-SC	12.87	9.39	-0.1	-0.1	2045	200-SC	54.33	29.25	-5.1	-5.5
316.00 Miscellaneous Power Plant Equipment	2021	200-SC	10.62	9.39			2045	200-SC	44.88	29.28	-3.5	-5.1
Total Springerville Unit 1									48.48	29.27	-4.2	-5.5
Springerville Unit 1 Common												
310.00 Rights-of-Way	2021	200-SC	28.42	9.38			2045	200-SC	49.87	29.27		
311.00 Structures and Improvements	2021	200-SC	17.98	9.38	-0.1	-0.1	2045	200-SC	49.61	29.27	-11.8	-16.8
312.00 Boiler Plant Equipment	2021	200-SC	15.67	9.39	-0.1	-0.1	2045	200-SC	50.76	29.27	-12.9	-16.8
314.00 Turbogenerator Units	2021	200-SC	20.92	9.38	-0.1	-0.1	2045	200-SC	52.60	29.26	-13.7	-16.8
315.00 Accessory Electric Equipment	2021	200-SC	15.50	9.39	-0.1	-0.1	2045	200-SC	56.09	29.25	-16.5	-16.8
316.00 Miscellaneous Power Plant Equipment	2021	200-SC	16.57	9.39			2045	200-SC	55.40	29.25	-15.0	-16.4
Total Springerville Unit 1 Common									50.69	29.27	-12.2	-16.6
Springerville Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2050	200-SC	50.98	36.57	-8.1	-7.6	2050	200-SC	46.76	33.86	-7.0	-6.7
312.00 Boiler Plant Equipment	2050	200-SC	50.50	36.57	-7.3	-7.6	2050	200-SC	47.64	33.86	-7.2	-6.7
314.00 Turbogenerator Units	2050	200-SC	51.50	36.56	-8.0	-7.6	2050	200-SC	44.78	33.87	-6.7	-6.7
315.00 Accessory Electric Equipment	2050	200-SC	55.14	36.55	-7.5	-7.6	2050	200-SC	53.98	33.83	-6.6	-6.7
316.00 Miscellaneous Power Plant Equipment	2050	200-SC	54.63	36.55	-6.8	-7.1	2050	200-SC	47.18	33.86	-6.1	-6.3
Total Springerville Unit 2									47.30	33.86	-7.0	-6.7

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	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Springerville Unit 2 Common (Leasehold Imp.)												
310.00 Rights-of-Way	2020	200-SC	29.45	8.40			2024	200-SC	33.31	9.38		
311.00 Structures and Improvements	2020	200-SC	20.67	8.41	-0.1	-0.1	2024	200-SC	21.21	9.38	-36.5	-39.4
312.00 Boiler Plant Equipment	2020	200-SC	16.90	8.41	-0.1	-0.1	2024	200-SC	16.91	9.39	-32.3	-39.4
314.00 Turbogenerator Units	2020	200-SC	21.89	8.41	-0.1	-0.1	2024	200-SC	25.40	9.38	-39.4	-39.4
315.00 Accessory Electric Equipment	2020	200-SC	27.50	8.41	-0.1	-0.1	2024	200-SC	31.60	9.38	-39.4	-39.4
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	20.55	8.41			2024	200-SC	22.26	9.38	-38.6	-39.3
Total Springerville Unit 2 Common									21.34	9.38	-34.4	-37.4
Springerville Coal Handling												
310.00 Rights-of-Way							2050	200-SC	61.72	33.79		
311.00 Structures and Improvements												
312.00 Boiler Plant Equipment	2021	200-SC	11.82	9.39	-0.1	-0.1	2050	200-SC	56.69	33.82	-57.2	-59.4
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment												
316.00 Miscellaneous Power Plant Equipment												
Total Springerville Coal Handling									56.74	33.82	-56.6	-58.7
Sundt												
310.00 Rights-of-Way												
311.00 Structures and Improvements									36.97	22.69	-42.1	-44.1
312.00 Boiler Plant Equipment									40.57	24.49	-37.6	-40.5
314.00 Turbogenerator Units									30.66	19.77	-50.0	-55.3
315.00 Accessory Electric Equipment									28.88	20.34	-45.9	-49.0
316.00 Miscellaneous Power Plant Equipment									26.85	19.56	-44.8	-50.9
Total Sundt									35.41	22.31	-42.0	-45.4
Sundt Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2018	200-SC	20.01	6.45	-52.6	-54.4	2028	200-SC	22.86	13.27	-53.9	-58.6
312.00 Boiler Plant Equipment	2018	200-SC	17.10	6.45	-33.3	-54.5	2028	200-SC	26.28	13.26	-49.3	-58.7
314.00 Turbogenerator Units	2018	200-SC	12.09	6.45	-49.7	-54.5	2028	200-SC	22.94	13.27	-52.4	-58.7
315.00 Accessory Electric Equipment	2018	200-SC	9.06	6.45	-53.8	-54.5	2028	200-SC	17.20	13.27	-54.0	-58.7
316.00 Miscellaneous Power Plant Equipment	2018	200-SC	10.84	6.45	-51.8	-54.4	2028	200-SC	18.52	13.27	-55.6	-58.6
Total Sundt Unit 1									22.58	13.27	-51.6	-58.7

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Account Description	Current Parameters						Proposed Parameters (at December 31, 2014)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2020	200-SC	19.23	8.41	-62.0	-64.2	2030	200-SC	21.69	15.19	-59.2	-66.3
312.00 Boiler Plant Equipment	2020	200-SC	20.39	8.41	-67.2	-64.2	2030	200-SC	28.86	15.19	-63.3	-66.3
314.00 Turbogenerator Units	2020	200-SC	20.59	8.41	-60.5	-64.2	2030	200-SC	30.70	15.19	-60.6	-66.2
315.00 Accessory Electric Equipment	2020	200-SC	11.91	8.41	-61.5	-64.3	2030	200-SC	18.62	15.20	-63.1	-66.4
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	13.45	8.41	-59.4	-64.2	2030	200-SC	19.76	15.20	-61.8	-66.2
Total Sundt Unit 2									25.66	15.19	-62.1	-66.3
Sundt Unit 3												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2022	200-SC	24.07	10.36	-71.5	-75.2	2032	200-SC	26.92	17.11	-67.8	-75.7
312.00 Boiler Plant Equipment	2022	200-SC	30.31	10.35	-76.9	-75.2	2032	200-SC	29.45	17.10	-70.8	-75.7
314.00 Turbogenerator Units	2022	200-SC	22.27	10.36	-73.2	-75.3	2032	200-SC	27.66	17.11	-68.5	-75.7
315.00 Accessory Electric Equipment	2022	200-SC	19.68	10.36	-67.5	-75.3	2032	200-SC	28.42	17.10	-67.1	-75.7
316.00 Miscellaneous Power Plant Equipment	2022	200-SC	15.48	10.36	-64.1	-75.2	2032	200-SC	23.16	17.11	-66.6	-75.5
Total Sundt Unit 3									28.24	17.11	-68.9	-75.7
Sundt Unit 4												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2048	200-SC	54.34	34.74	-24.5	-24.6	2048	200-SC	52.99	32.01	-32.0	-32.6
312.00 Boiler Plant Equipment	2048	200-SC	54.34	34.74	-24.1	-24.6	2048	200-SC	54.25	32.00	-30.3	-32.6
314.00 Turbogenerator Units	2048	200-SC	49.18	34.76	-24.7	-24.6	2048	200-SC	41.75	32.06	-29.5	-32.6
315.00 Accessory Electric Equipment	2048	200-SC	53.12	34.75	-23.9	-24.6	2048	200-SC	47.13	32.04	-31.1	-32.6
316.00 Miscellaneous Power Plant Equipment	2048	200-SC	48.38	34.77	-20.0	-24.2	2048	200-SC	44.82	32.05	-26.9	-32.2
Total Sundt Unit 4									50.81	32.02	-30.5	-32.6
Sundt Solar Booster (Areva)												
310.00 Rights-of-Way												
311.00 Structures and Improvements	30.00	SQ	30.00									
312.00 Boiler Plant Equipment	30.00	SQ	30.00				2048	200-SC	32.56	32.10	-0.4	-0.4
314.00 Turbogenerator Units	30.00	SQ	30.00									
315.00 Accessory Electric Equipment	30.00	SQ	30.00									
316.00 Miscellaneous Power Plant Equipment	30.00	SQ	30.00									
Total Sundt Solar Booster (Areva)									32.56	32.10	-0.4	-0.4

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Account Description	Current Parameters						Proposed Parameters (at December 31, 2014)					
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A	B	C	D	E	F	G	H	I	J	K	L	M
OTHER PRODUCTION (by Unit)												
DeMoss Petrie Gas Unit 1												
341.00 Structures and Improvements	2046	200-SC	40.04	32.98	-7.9	-9.2	2046	200-SC	36.97	30.24	-7.3	-9.0
342.00 Fuel Holders, Products and Accessories	2046	200-SC	42.61	32.97	-9.2	-9.2	2046	200-SC	42.70	30.22	-8.9	-9.0
343.00 Prime Movers	2046	200-SC	34.38	33.01	-9.2	-9.2	2046	200-SC	34.41	30.25	-1.3	-9.0
344.00 Generators and Devices	2046	200-SC	42.59	32.97	-9.2	-9.2	2046	200-SC	42.56	30.22	-8.7	-9.0
345.00 Accessory Electric Equipment	2046	200-SC	42.54	32.97	-9.2	-9.2	2046	200-SC	41.80	30.22	-3.4	-9.0
346.00 Miscellaneous Power Plant Equipment	2046	200-SC	41.25	32.98	-9.2	-9.2	2046	200-SC	40.73	30.22	-8.9	-9.0
Total DeMoss Petrie Gas Unit 1									42.35	30.22	-8.3	-9.0
Gila River												
341.00 Structures and Improvements									42.18	32.06	-8.4	-8.4
342.00 Fuel Holders, Products and Accessories									42.49	32.06	-8.4	-8.4
343.00 Prime Movers									41.47	32.06	-8.3	-8.3
344.00 Generators and Devices									42.63	32.06	-8.3	-8.3
345.00 Accessory Electric Equipment									42.38	32.06	-8.3	-8.3
346.00 Miscellaneous Power Plant Equipment									42.28	32.06	-8.4	-8.4
Total Gila River									41.72	32.06	-8.3	-8.3
Gila River Unit 3												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-8.3	-8.3
342.00 Fuel Holders, Products and Accessories	45.00	SQ	45.00				2048	200-SC	41.24	32.06	-8.3	-8.3
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	41.57	32.06	-8.3	-8.3
344.00 Generators and Devices	45.00	SQ	45.00				2048	200-SC	42.63	32.06	-8.3	-8.3
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-8.3	-8.3
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	41.89	32.06	-8.3	-8.3
Total Gila River Unit 3									41.75	32.06	-8.3	-8.3
Gila River Common												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.15	32.06	-8.4	-8.4
342.00 Fuel Holders, Products and Accessories	45.00	SQ	45.00				2048	200-SC	42.52	32.06	-8.4	-8.4
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	39.05	32.07	-8.4	-8.4
344.00 Generators and Devices	45.00	SQ	45.00									
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.39	32.06	-8.4	-8.4
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	42.29	32.06	-8.4	-8.4
Total Gila River Common									41.49	32.06	-8.4	-8.4

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Account Description	Current Parameters						Proposed Parameters (at December 31, 2014)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Luna												
341.00 Structures and Improvements	2051	200-SC	42.47	37.52	-19.5	-19.6	2051	200-SC	42.38	34.80	-18.7	-18.8
342.00 Fuel Holders, Products and Accessories	2051	200-SC	42.51	37.52	-19.6	-19.6	2051	200-SC	42.56	34.80	-18.8	-18.8
343.00 Prime Movers	2051	200-SC	39.20	37.54	-16.3	-19.7	2051	200-SC	37.40	34.82	-15.5	-18.8
344.00 Generators and Devices	2051	200-SC	41.74	37.52	-14.5	-19.6	2051	200-SC	40.73	34.80	-11.1	-18.8
345.00 Accessory Electric Equipment	40.00		40.00				2051	200-SC	35.29	34.83	-18.8	-18.8
346.00 Miscellaneous Power Plant Equipment	2051	200-SC	42.48	37.52	-19.6	-19.6	2051	200-SC	42.48	34.80	-18.7	-18.8
Total Luna									40.97	34.80	-16.0	-18.8
North Loop Gas												
341.00 Structures and Improvements			24.42	7.02	-11.2	-12.1			34.58	13.74	-13.4	-14.2
342.00 Fuel Holders, Products and Accessories			43.49	33.88	-5.9	-5.9			42.70	30.22	-5.7	-5.7
343.00 Prime Movers			8.36	5.46	-12.5	-12.5			15.51	12.30	-12.4	-15.4
344.00 Generators and Devices			36.87	19.70	-8.5	-8.9			42.21	22.77	-9.3	-9.8
345.00 Accessory Electric Equipment			27.62	12.41	-9.3	-10.3			33.62	17.60	-10.7	-11.9
346.00 Miscellaneous Power Plant Equipment			27.71	8.02	-10.4	-11.7			38.64	14.59	-12.2	-13.7
Total North Loop Gas									37.09	20.31	-9.8	-10.5
North Loop Gas Unit 1												
341.00 Structures and Improvements	2017	200-SC	19.02	5.46	-11.1	-11.1	2027	200-SC	29.10	12.30	-13.4	-13.4
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2017	200-SC	9.86	5.46	-11.1	-11.1	2027	200-SC	19.70	12.30	-13.3	-13.4
344.00 Generators and Devices	2017	200-SC	27.57	5.46	-11.0	-11.1	2027	200-SC	38.80	12.29	-13.1	-13.4
345.00 Accessory Electric Equipment	2017	200-SC	20.04	5.46	-10.9	-11.1	2027	200-SC	28.69	12.30	-13.1	-13.4
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	19.46	5.46	-11.1	-11.1	2027	200-SC	30.66	12.30	-13.4	-13.4
Total North Loop Gas Unit 1									32.33	12.29	-13.1	-13.4
North Loop Gas Unit 2												
341.00 Structures and Improvements	2017	200-SC	30.61	5.46	-15.5	-15.5	2027	200-SC	41.27	12.29	-17.9	-17.9
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2017	200-SC	15.82	5.46	-15.5	-15.5	2027	200-SC	8.23	12.31	-7.0	-17.9
344.00 Generators and Devices	2017	200-SC	31.80	5.46	-14.7	-15.5	2027	200-SC	43.04	12.29	-16.9	-17.9
345.00 Accessory Electric Equipment	2017	200-SC	25.59	5.46	-15.1	-15.5	2027	200-SC	31.85	12.29	-17.3	-17.9
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	44.27	5.46	-15.5	-15.5	2027	200-SC	53.34	12.28	-17.8	-17.8
Total North Loop Gas Unit 2									33.25	12.29	-15.7	-17.9

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	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
North Loop Gas Unit 3												
341.00 Structures and Improvements	2017	200-SC	30.61	5.46	-13.3	-13.3	2027	200-SC	41.27	12.29	-16.1	-16.1
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2017	200-SC	7.31	5.46	-13.3	-13.3	2027	200-SC	17.12	12.30	-15.4	-16.1
344.00 Generators and Devices	2017	200-SC	32.28	5.46	-12.0	-13.3	2027	200-SC	43.69	12.29	-14.5	-16.1
345.00 Accessory Electric Equipment	2017	200-SC	25.63	5.46	-13.0	-13.3	2027	200-SC	31.87	12.29	-15.6	-16.1
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	44.27	5.46	-13.3	-13.3	2027	200-SC	53.34	12.28	-16.1	-16.1
Total North Loop Gas Unit 3									32.54	12.29	-14.9	-16.1
North Loop Gas Unit 4												
341.00 Structures and Improvements	2047	200-SC	42.41	33.89	2.7	-5.9	2046	200-SC	41.22	30.22	2.6	-5.7
342.00 Fuel Holders, Products and Accessories	2047	200-SC	43.49	33.88	-5.9	-5.9	2046	200-SC	42.70	30.22	-5.7	-5.7
343.00 Prime Movers												
344.00 Generators and Devices	2047	200-SC	43.46	33.88	-5.6	-5.9	2046	200-SC	42.66	30.22	-5.4	-5.7
345.00 Accessory Electric Equipment	2047	200-SC	42.61	33.89	-4.7	-5.9	2046	200-SC	41.29	30.22	-4.5	-5.7
346.00 Miscellaneous Power Plant Equipment	2047	200-SC	43.49	33.88	-3.2	-5.9	2046	200-SC	42.70	30.22	-3.1	-5.7
Total North Loop Gas Unit 4									42.56	30.22	-5.3	-5.7
Solar Units (Generators and Devices)												
344.00 DeMoss Petrie	20.00	S4	20.00	17.06			28.00	S6	28.00	16.15	-5.0	-5.0
344.00 Fort Huachuca	20.00	S4	20.00	17.06			28.00	S6	28.00	27.50	-5.0	-5.0
344.00 HQ Rooftop	20.00	S4	20.00	17.06			28.00	S6	28.00	25.50	-5.0	-5.0
344.00 OH Rooftop	20.00	S4	20.00	17.06			28.00	S6	28.00	24.50	-5.0	-5.0
344.00 OH Test Yard	20.00	S4	20.00	17.06			28.00	S6	28.00	16.83	-5.0	-5.0
344.00 Prairie Fire	20.00	S4	20.00	17.06			28.00	S6	28.00	25.50	-5.0	-5.0
344.00 Springerville Sites 1-3 (Legacy)	20.00	S4	20.00	17.06			28.00	S6	28.00	16.11	-5.0	-5.0
344.00 Springerville Site 4	20.00	S4	20.00	17.06			28.00	S6	28.00	23.50	-5.0	-5.0
344.00 Tucson							28.00	S6	28.00	11.82	-5.0	-5.0
344.00 U of A Tech Park Site 1	20.00	S4	20.00	17.06			28.00	S6	28.00	23.50	-5.0	-5.0
344.00 U of A Tech Park Site 2							28.00	S6	28.00	24.50	-5.0	-5.0
344.00 White Mountain							28.00	S6	28.00	27.50	-5.0	-5.0
Total Solar Units									28.00	24.49	-5.0	-5.0

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A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Gas												
341.00 Structures and Improvements			28.10	5.46	-1.8	-1.8			37.43	12.29	-1.9	-2.2
342.00 Fuel Holders, Products and Accessories			9.71	5.46	-1.8	-1.8			19.39	12.30	-2.2	-2.2
343.00 Prime Movers			15.82	5.46	-1.8	-1.8			25.38	12.30	-2.2	-2.2
344.00 Generators and Devices			30.02	5.46	-1.7	-1.7			39.83	12.29	-2.0	-2.1
345.00 Accessory Electric Equipment			22.40	5.46	-1.7	-1.8			34.86	12.29	-2.1	-2.2
346.00 Miscellaneous Power Plant Equipment			42.42	5.46	-1.8	-1.8			51.58	12.28	-2.2	-2.2
Total Sundt Gas									36.18	12.29	-2.0	-2.1
Sundt Gas Unit 1												
341.00 Structures and Improvements	2017	200-SC	28.10	5.46	-1.7	-1.7	2027	200-SC	37.43	12.29	-1.8	-2.1
342.00 Fuel Holders, Products and Accessories	2017	200-SC	9.71	5.46	-1.7	-1.7	2027	200-SC	19.39	12.30	-2.1	-2.1
343.00 Prime Movers	2017	200-SC	15.82	5.46	-1.7	-1.7	2027	200-SC	25.38	12.30	-2.1	-2.1
344.00 Generators and Devices	2017	200-SC	31.37	5.46	-1.7	-1.7	2027	200-SC	40.65	12.29	-2.0	-2.1
345.00 Accessory Electric Equipment	2017	200-SC	23.05	5.46	-1.7	-1.7	2027	200-SC	35.64	12.29	-2.0	-2.1
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	42.93	5.46	-1.7	-1.7	2027	200-SC	52.10	12.28	-2.1	-2.1
Total Sundt Gas Unit 1									36.88	12.29	-2.0	-2.1
Sundt Gas Unit 2												
341.00 Structures and Improvements	2017	200-SC	28.10	5.46	-1.8	-1.8	2027	200-SC	37.43	12.29	-1.9	-2.2
342.00 Fuel Holders, Products and Accessories	2017	200-SC	9.71	5.46	-1.8	-1.8	2027	200-SC	19.39	12.30	-2.2	-2.2
343.00 Prime Movers	2017	200-SC	15.82	5.46	-1.8	-1.8	2027	200-SC	25.38	12.30	-2.2	-2.2
344.00 Generators and Devices	2017	200-SC	28.72	5.46	-1.7	-1.8	2027	200-SC	38.99	12.29	-1.9	-2.2
345.00 Accessory Electric Equipment	2017	200-SC	21.84	5.46	-1.8	-1.8	2027	200-SC	34.18	12.29	-2.1	-2.2
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	42.08	5.46	-1.8	-1.8	2027	200-SC	51.24	12.28	-2.2	-2.2
Total Sundt Gas Unit 2									35.47	12.29	-2.0	-2.2

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the TEP study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes examples of the supporting schedules developed for distribution Account 364.00 (Poles, Towers and Fixtures). Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the TEP study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Net Salvage History.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Aging of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting

Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived projection life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – NET SALVAGE HISTORY

An Unadjusted Net Salvage History contains recorded activity–year retirements, salvage, cost of removal and other depreciation reserve activity appropriately recognized in the computation of average net salvage rates. This schedule provides a moving–average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving–average analysis of the components of unadjusted net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

An Adjusted Net Salvage History contains recorded activity–year total retirements, salvage, cost of removal and other depreciation reserve activity appropriately adjusted in the estimation of future net salvage rates. The moving–average adjusted net salvage analysis and component analysis are displayed in columns corresponding to an unadjusted net salvage analysis.

TUCSON ELECTRIC POWER COMPANY

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 55 - R2.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2014 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2014	0.5	9,740,855	55.00	54.53	0.9914	1.0000	9,657,263	177,108
2013	1.5	23,800,754	55.00	53.59	0.9743	1.0000	23,188,590	432,743
2012	2.5	25,286,360	55.01	52.65	0.9570	1.0000	24,198,197	459,642
2011	3.5	24,869,733	55.04	51.71	0.9394	1.0000	23,363,675	451,820
2010	4.5	8,388,159	54.95	50.78	0.9240	1.0000	7,751,061	152,646
2009	5.5	5,029,314	54.93	49.85	0.9075	1.0000	4,564,241	91,560
2008	6.5	4,036,772	54.97	48.93	0.8901	1.0000	3,592,975	73,436
2007	7.5	3,851,451	54.95	48.01	0.8737	1.0000	3,364,824	70,090
2006	8.5	4,754,782	54.98	47.09	0.8565	1.0000	4,072,351	86,476
2005	9.5	4,141,632	55.02	46.18	0.8394	1.0000	3,476,613	75,281
2004	10.5	5,016,957	55.05	45.28	0.8224	1.0000	4,126,142	91,132
2003	11.5	3,345,173	55.05	44.38	0.8061	1.0000	2,696,401	60,762
2002	12.5	4,742,134	55.01	43.48	0.7904	1.0000	3,748,101	86,200
2001	13.5	5,835,346	55.07	42.59	0.7734	1.0000	4,513,114	105,962
2000	14.5	2,083,580	55.12	41.71	0.7567	1.0000	1,576,738	37,804
1999	15.5	2,023,220	54.99	40.83	0.7426	1.0000	1,502,352	36,795
1998	16.5	2,198,533	55.11	39.96	0.7251	1.0000	1,594,110	39,894
1997	17.5	3,643,997	55.15	39.09	0.7088	1.0000	2,582,919	66,069
1996	18.5	3,260,736	54.97	38.24	0.6956	1.0000	2,268,148	59,321
1995	19.5	3,086,950	55.12	37.38	0.6782	1.0000	2,093,635	56,004
1994	20.5	1,839,508	54.61	36.54	0.6690	1.0000	1,230,665	33,681
1993	21.5	2,348,495	54.81	35.70	0.6513	1.0000	1,529,557	42,845
1992	22.5	4,127,225	54.92	34.87	0.6349	1.0000	2,620,274	75,146
1991	23.5	3,423,020	54.71	34.05	0.6223	1.0000	2,130,090	62,564
1990	24.5	1,884,075	53.43	33.23	0.6219	1.0000	1,171,782	35,262
1989	25.5	3,573,822	54.22	32.42	0.5980	1.0000	2,137,090	65,913
1988	26.5	3,376,623	54.44	31.62	0.5809	1.0000	1,961,512	62,029
1987	27.5	2,546,832	54.42	30.83	0.5665	1.0000	1,442,739	46,796
1986	28.5	2,695,532	54.68	30.05	0.5495	1.0000	1,481,128	49,293
1985	29.5	3,610,030	54.66	29.27	0.5355	1.0000	1,933,162	66,041
1984	30.5	2,817,291	54.65	28.51	0.5216	1.0000	1,469,534	51,552
1983	31.5	3,023,267	55.06	27.75	0.5039	1.0000	1,523,550	54,906
1982	32.5	2,401,285	55.33	27.00	0.4879	1.0000	1,171,647	43,396
1981	33.5	3,035,127	55.55	26.26	0.4727	1.0000	1,434,832	54,640
1980	34.5	2,846,562	55.64	25.53	0.4588	1.0000	1,306,027	51,157
1979	35.5	2,662,839	55.79	24.81	0.4447	1.0000	1,184,081	47,727
1978	36.5	2,271,238	55.50	24.10	0.4342	1.0000	986,135	40,920

TUCSON ELECTRIC POWER COMPANY

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 55 - R2.5
Procedure: Vintage Group

Generation Arrangement

	December 31, 2014							
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1977	37.5	1,569,572	55.61	23.40	0.4207	1.0000	660,383	28,223
1976	38.5	1,420,363	56.24	22.71	0.4038	1.0000	573,531	25,256
1975	39.5	964,764	48.74	22.03	0.4520	1.0000	436,095	19,796
1974	40.5	2,194,546	56.33	21.36	0.3792	1.0000	832,277	38,962
1973	41.5	1,722,297	55.83	20.70	0.3709	1.0000	638,749	30,850
1972	42.5	1,207,492	55.17	20.06	0.3636	1.0000	439,042	21,887
1971	43.5	1,284,527	55.25	19.43	0.3516	1.0000	451,632	23,248
1970	44.5	1,123,959	56.54	18.81	0.3326	1.0000	373,854	19,879
1969	45.5	1,423,206	57.47	18.20	0.3167	1.0000	450,717	24,766
1968	46.5	985,798	57.23	17.61	0.3076	1.0000	303,272	17,226
1967	47.5	523,158	57.76	17.02	0.2947	1.0000	154,190	9,057
1966	48.5	502,979	58.19	16.46	0.2828	1.0000	142,255	8,643
1965	49.5	489,645	58.34	15.91	0.2727	1.0000	133,508	8,393
1964	50.5	793,572	57.95	15.37	0.2652	1.0000	210,470	13,693
1963	51.5	1,348,515	59.38	14.85	0.2501	1.0000	337,215	22,710
1962	52.5	1,337,973	59.40	14.34	0.2415	1.0000	323,080	22,525
1961	53.5	1,090,810	60.06	13.85	0.2307	1.0000	251,599	18,163
1960	54.5	632,186	59.59	13.38	0.2245	1.0000	141,926	10,609
1959	55.5	485,215	60.12	12.92	0.2149	1.0000	104,261	8,071
1958	56.5	393,613	60.20	12.48	0.2072	1.0000	81,574	6,538
1957	57.5	364,744	60.59	12.05	0.1989	1.0000	72,531	6,020
1956	58.5	406,424	61.25	11.64	0.1900	1.0000	77,221	6,635
1955	59.5	367,941	62.36	11.24	0.1803	1.0000	66,335	5,901
1954	60.5	148,796	62.30	10.86	0.1743	1.0000	25,941	2,388
1953	61.5	203,866	62.19	10.50	0.1688	1.0000	34,408	3,278
1952	62.5	382,527	63.96	10.14	0.1586	1.0000	60,671	5,981
1951	63.5	161,020	63.90	9.81	0.1535	1.0000	24,711	2,520
1950	64.5	148,176	61.74	9.48	0.1536	1.0000	22,755	2,400
1949	65.5	102,268	64.91	9.17	0.1413	1.0000	14,447	1,576
1948	66.5	329,679	66.15	8.87	0.1341	1.0000	44,204	4,984
1947	67.5	131,893	66.37	8.58	0.1292	1.0000	17,046	1,987
1946	68.5	60,678	67.31	8.30	0.1233	1.0000	7,479	902
1945	69.5	23,689	67.30	8.02	0.1192	1.0000	2,824	352
1944	70.5	7,193	69.41	7.76	0.1118	1.0000	804	104
1943	71.5	1,630	69.74	7.50	0.1076	1.0000	175	23
1942	72.5	6,501	67.02	7.25	0.1082	1.0000	703	97
1941	73.5	4,478	60.10	7.00	0.1165	1.0000	522	74

TUCSON ELECTRIC POWER COMPANY

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 55 - R2.5
Procedure: Vintage Group

Generation Arrangement

	December 31, 2014							
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1940	74.5	11,938	71.69	6.76	0.0943	1.0000	1,126	167
1939	75.5	8,794	73.04	6.52	0.0893	1.0000	786	120
1938	76.5	4,112	74.16	6.29	0.0848	1.0000	349	55
1937	77.5	3,899	75.16	6.06	0.0806	1.0000	314	52
1936	78.5	1,648	75.91	5.83	0.0768	1.0000	127	22
1935	79.5	1,950	77.31	5.60	0.0725	1.0000	141	25
1934	80.5	818	77.54	5.38	0.0694	1.0000	57	11
1933	81.5	1,996	78.60	5.16	0.0657	1.0000	131	25
1932	82.5	2,505	80.28	4.95	0.0616	1.0000	154	31
1931	83.5	1,881	80.88	4.73	0.0585	1.0000	110	23
1930	84.5	2,533	81.56	4.51	0.0553	1.0000	140	31
Total	15.5	$222,006,967	55.24	41.84	0.7575	1.0000	$168,161,101	$4,018,893

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2014	Derived Additions	1989 Opening Balance	Experience to 12/31/2014 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2014	0.5	9,755,652		9,740,855	0.9985	0.4992
2013	1.5	23,861,351		23,800,754	0.9975	1.4986
2012	2.5	25,192,104		25,286,360	1.0037	2.5098
2011	3.5	24,607,921		24,869,733	1.0106	3.5368
2010	4.5	8,597,818		8,388,159	0.9756	4.4403
2009	5.5	5,205,189		5,029,314	0.9662	5.4119
2008	6.5	4,127,468		4,036,772	0.9780	6.4451
2007	7.5	3,965,761		3,851,451	0.9712	7.4161
2006	8.5	4,847,219		4,754,782	0.9809	8.4392
2005	9.5	4,226,395		4,141,632	0.9799	9.4585
2004	10.5	5,056,066		5,016,957	0.9923	10.4798
2003	11.5	3,404,275		3,345,173	0.9826	11.4653
2002	12.5	4,892,972		4,742,134	0.9692	12.4060
2001	13.5	5,995,916		5,835,346	0.9732	13.4418
2000	14.5	2,114,651		2,083,580	0.9853	14.4633
1999	15.5	2,129,196		2,023,220	0.9502	15.3076
1998	16.5	2,270,138		2,198,533	0.9685	16.4007
1997	17.5	3,713,015		3,643,997	0.9814	17.4121
1996	18.5	3,395,318		3,260,736	0.9604	18.1896
1995	19.5	3,214,275		3,086,950	0.9604	19.3016
1994	20.5	1,986,494		1,839,508	0.9260	19.7527
1993	21.5	2,486,545		2,348,495	0.9445	20.9038
1992	22.5	4,335,956		4,127,225	0.9519	21.9603
1991	23.5	3,656,718		3,423,020	0.9361	22.6923
1990	24.5	2,163,363		1,884,075	0.8709	22.3490
1989	25.5	3,944,684		3,573,822	0.9060	24.0707
1988	26.5		3,662,824	3,376,623	0.9219	25.2144
1987	27.5		2,787,446	2,546,832	0.9137	26.1231
1986	28.5		2,964,885	2,695,532	0.9092	27.2972
1985	29.5		4,028,830	3,610,030	0.8960	28.1853
1984	30.5		3,148,303	2,817,291	0.8949	29.0720
1983	31.5		3,305,135	3,023,267	0.9147	30.3782
1982	32.5		2,616,718	2,401,285	0.9177	31.5360
1981	33.5		3,261,800	3,035,127	0.9305	32.6262
1980	34.5		3,100,138	2,846,562	0.9182	33.5909
1979	35.5		2,898,845	2,662,839	0.9186	34.5996
1978	36.5		2,507,643	2,271,238	0.9057	35.1598
1977	37.5		1,770,817	1,569,572	0.8864	36.1069

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2014	Derived Additions	1989 Opening Balance	Experience to 12/31/2014 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1976	38.5		1,549,656	1,420,363	0.9166	37.5598
1975	39.5		1,570,716	964,764	0.6142	30.8739
1974	40.5		2,557,849	2,194,546	0.8580	39.2693
1973	41.5		1,981,827	1,722,297	0.8690	39.5628
1972	42.5		1,477,248	1,207,492	0.8174	39.6840
1971	43.5		1,581,742	1,284,527	0.8121	40.5317
1970	44.5		1,309,103	1,123,959	0.8586	42.5683
1969	45.5		1,594,429	1,423,206	0.8926	44.2310
1968	46.5		1,142,953	985,798	0.8625	44.7103
1967	47.5		612,332	523,158	0.8544	45.9509
1966	48.5		565,758	502,979	0.8890	47.0650
1965	49.5		560,063	489,645	0.8743	47.8761
1964	50.5		941,991	793,572	0.8424	48.1397
1963	51.5		1,510,686	1,348,515	0.8927	50.1957
1962	52.5		1,537,009	1,337,973	0.8705	50.8214
1961	53.5		1,234,636	1,090,810	0.8835	52.0679
1960	54.5		804,195	632,186	0.7861	52.1641
1959	55.5		762,437	485,215	0.6364	53.2414
1958	56.5		634,696	393,613	0.6202	53.8416
1957	57.5		592,246	364,744	0.6159	54.7326
1956	58.5		638,164	406,424	0.6369	55.8665
1955	59.5		550,015	367,941	0.6690	57.4221
1954	60.5		232,114	148,796	0.6410	57.7937
1953	61.5		341,656	203,866	0.5967	58.0834
1952	62.5		578,387	382,527	0.6614	60.2346
1951	63.5		256,324	161,020	0.6282	60.5300
1950	64.5		379,679	148,176	0.3903	58.7062
1949	65.5		173,146	102,268	0.5906	62.1809
1948	66.5		541,754	329,679	0.6085	63.7022
1947	67.5		225,802	131,893	0.5841	64.1924
1946	68.5		107,195	60,678	0.5661	65.3726
1945	69.5		45,510	23,689	0.5205	65.5924
1944	70.5		12,945	7,193	0.5556	67.9052
1943	71.5		3,161	1,630	0.5156	68.4155
1942	72.5		18,486	6,501	0.3517	65.8689
1941	73.5		29,283	4,478	0.1529	59.1007
1940	74.5		26,194	11,938	0.4558	70.8222
1939	75.5		15,720	8,794	0.5594	72.2895

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2014	Derived Additions	1989 Opening Balance	Experience to 12/31/2014 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1938	76.5		7,693	4,112	0.5345	73.5203
1937	77.5		7,052	3,899	0.5528	74.6208
1936	78.5		3,305	1,648	0.4988	75.4482
1935	79.5		4,396	1,950	0.4436	76.9297
1934	80.5		1,496	818	0.5467	77.2184
1933	81.5		3,844	1,996	0.5193	78.3300
1932	82.5		4,221	2,505	0.5934	80.0626
1931	83.5		3,637	1,881	0.5171	80.7019
1930	84.5		8,290	2,533	0.3055	81.4199
1929	85.5		62		0.0000	68.6874
1928	86.5		35		0.0000	77.0000
1927	87.5		55		0.0000	69.0000
1926	88.5		12		0.0000	79.0000
Total	15.5	$169,146,458	$64,794,589	$222,006,967	0.9490	

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1989	44,344,776	3,123,602	643,857	(1,152)	46,823,370
1990	46,823,370	2,237,399	550,895	(93)	48,509,780
1991	48,509,780	3,045,228	544,557		51,010,451
1992	51,010,451	3,556,393	500,697	(6,694)	54,059,453
1993	54,059,453	2,798,989	474,345	310,829	56,694,926
1994	56,694,926	2,766,210	642,086	11,403	58,830,453
1995	58,830,453	2,626,121	463,782		60,992,792
1996	60,992,792	2,029,805	467,048		62,555,549
1997	62,555,549	2,214,412	554,778		64,215,183
1998	64,215,183	3,102,562	205,176	18,059	67,130,628
1999	67,130,628	656,993	30,068		67,757,553
2000	67,757,553	5,308,924			73,066,477
2001	73,066,477	8,193,570	12,071		81,247,976
2002	81,247,976	5,459,971	196,636		86,511,312
2003	86,511,312	5,270,466	90,497		91,691,280
2004	91,691,280	4,402,769			96,094,049
2005	96,094,049	6,658,267	226,291		102,526,025
2006	102,526,025	10,595,487	136,154		112,985,358
2007	112,985,358	5,138,401	130,731		117,993,028
2008	117,993,028	6,518,177	(674)		124,511,879
2009	124,511,879	9,930,500	113,834	(621,860)	133,706,685
2010	133,706,685	8,872,197	843,269		141,735,614
2011	141,735,614	23,935,498	6,277,251		159,393,861
2012	159,393,861	25,488,117	23,622,435		161,259,543
2013	161,259,543	22,881,403	21,040,307		163,100,639
2014	163,100,639	13,145,332	17,726,165	63,487,161	222,006,967

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1989	44,250,482	3,087,400	643,857	(1,152)	46,692,873
1990	46,692,873	2,411,979	550,895	(93)	48,553,863
1991	48,553,863	3,056,776	544,557		51,066,082
1992	51,066,082	3,535,937	500,697	(6,694)	54,094,627
1993	54,094,627	2,841,892	579,155	415,639	56,773,003
1994	56,773,003	2,767,505	642,086	11,403	58,909,825
1995	58,909,825	2,616,839	463,782		61,062,882
1996	61,062,882	2,063,749	467,048		62,659,583
1997	62,659,583	2,438,239	554,778		64,543,044
1998	64,543,044	3,196,710	205,176	18,059	67,552,637
1999	67,552,637	8,866,659	30,068		76,389,228
2000	76,389,228	1,947,897			78,337,125
2001	78,337,125	4,917,616	12,071		83,242,670
2002	83,242,670	5,239,635	196,636		88,285,669
2003	88,285,669	5,057,777	90,497		93,252,949
2004	93,252,949	6,283,475			99,536,424
2005	99,536,424	7,279,834	226,291		106,589,968
2006	106,589,968	8,730,779	127,621		115,193,125
2007	115,193,125	5,393,737	135,272		120,451,590
2008	120,451,590	5,442,881	3,318		125,891,153
2009	125,891,153	10,683,102	113,834	(621,860)	135,838,562
2010	135,838,562	8,597,818	760,533		143,675,847
2011	143,675,847	24,742,540	1,762,639	(175,825)	166,479,923
2012	166,479,923	25,233,310	1,229,043		190,484,190
2013	190,484,190	23,861,351	1,029,097		213,316,444
2014	213,316,444	9,755,652	1,065,129		222,006,967

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1926-2014
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree Average Life	First Degree Dispersion	First Degree Conf. Index	Second Degree Average Life	Second Degree Dispersion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Dispersion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1989-1993	28.5	56.1	O2	3.73	91.2	O4 *	5.97	47.4	R0.5	2.44
1990-1994	26.0	57.4	O2	5.02	48.6	S-.5	1.80	93.0	O4 *	4.82
1991-1995	9.3	57.0	L0	13.86	48.3	R0.5	10.05	45.2	R1	7.53
1992-1996	2.2	59.0	L0	13.83	51.9	S-.5	11.25	47.1	R1	7.93
1993-1997	5.9	61.9	L0	15.10	53.4	S-.5	12.31	48.2	R1	8.84
1994-1998	8.8	69.2	L0	17.30	57.0	S0	13.69	52.2	R1	10.96
1995-1999	22.3	85.3	L0	18.39	67.2	S0	15.22	58.0	R2	11.53
1996-2000	67.9	110.9	SC	0.73	110.5	SC	0.75	83.8	R1.5	1.08
1997-2001	72.3	136.1	R0.5	2.35	126.0	S0	2.02	90.6	R2	0.82
1998-2002	67.1	113.6	L1.5 *	5.81	72.4	S2 *	7.27	62.1	R4 *	17.99
1999-2003	50.5	108.3	L1.5 *	11.22	70.2	S2 *	4.72	62.6	S4 *	12.33
2000-2004	60.6	113.8	L1.5 *	7.96	72.8	S2 *	6.09	65.1	R4 *	13.99
2001-2005	0.0	88.7	L1.5 *	32.91	60.8	S3 *	16.64	56.4	S4 *	8.90
2002-2006	0.0	83.6	L1.5 *	31.12	59.0	S3 *	15.05	55.5	S4 *	8.28
2003-2007	0.0	88.9	L1.5 *	33.39	60.8	S3 *	17.45	56.4	S4 *	10.29
2004-2008	0.0	97.4	L1.5 *	35.75	63.8	S3 *	20.18	58.1	S4 *	11.77
2005-2009	12.1	105.1	L1.5 *	23.49	70.1	S3 *	11.30	64.7	S4 *	4.84
2006-2010	11.7	102.6	L1.5 *	19.36	72.7	S2 *	10.12	66.6	R4 *	4.33
2007-2011	2.9	68.7	L1.5 *	15.37	57.6	R3 *	5.44	56.7	R4 *	2.73
2008-2012	2.9	64.7	L1.5 *	11.71	57.0	R2.5	4.12	55.2	R3	2.48
2009-2013	5.0	63.5	L1.5 *	9.65	56.8	R2.5	3.35	54.7	R2.5	2.40
2010-2014	4.2	60.4	L1.5 *	8.56	55.6	S1.5	3.19	53.7	R2	1.98

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

Placement Band: 1926-2014

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1989-2014	5.8	72.0	L1	13.39	59.1	R2	4.45	56.4	R2.5	2.33
1991-2014	5.9	72.6	L1 *	13.54	59.6	R2.5	4.29	57.0	R2.5	2.34
1993-2014	6.0	73.1	L1.5 *	13.69	60.1	R2.5	4.27	57.4	R3	2.38
1995-2014	6.1	73.7	L1.5 *	13.84	60.7	S2	4.19	58.1	R3	2.42
1997-2014	6.2	74.1	L1.5 *	13.92	61.2	S2	4.11	58.6	R3	2.43
1999-2014	6.2	73.9	L1.5 *	13.78	61.4	S2 *	3.99	59.0	R3	2.45
2001-2014	6.1	72.3	L1.5 *	13.08	60.9	S2	3.76	58.5	R3	2.41
2003-2014	6.1	71.4	L1.5 *	12.62	60.7	S2	3.75	58.3	R3	2.34
2005-2014	5.8	69.2	L1.5 *	11.82	59.8	S2	3.62	57.5	R3	2.35
2007-2014	6.6	68.5	L1.5 *	10.65	59.8	S2	3.43	57.4	R2.5	2.21
2009-2014	6.3	64.9	L1.5 *	9.10	58.1	S1.5	3.09	55.8	R2.5	2.08
2011-2014	4.9	58.2	L1.5 *	7.69	54.5	S1.5	3.12	52.7	R2	2.49
2013-2014	22.3	73.7	L1	5.20	69.5	S0	4.04	66.9	S0.5	3.45

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

Placement Band: 1926-2014

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1989-1990	30.5	52.3	O2	3.38	119.6	SC *	11.32	43.5	R0.5	3.62
1989-1992	22.4	54.4	O2	4.82	77.7	O4 *	6.41	46.7	R0.5	3.30
1989-1994	27.4	55.5	O2	3.37	67.3	O3 *	4.43	48.6	S-.5	2.30
1989-1996	2.4	57.8	L0	12.82	53.9	L0	11.81	45.9	R1	7.16
1989-1998	9.3	63.8	O2	14.22	58.5	L0	13.11	49.8	R1	9.26
1989-2000	32.4	76.7	O2	9.33	78.6	O2	9.54	58.0	R1	6.49
1989-2002	39.6	79.7	L0	6.83	64.1	S0	4.01	53.6	R2	8.19
1989-2004	44.9	87.6	L0	5.72	69.0	S0	2.91	57.4	R2	8.57
1989-2006	0.0	83.0	L0.5	27.73	60.0	R2	17.86	53.1	R3	8.24
1989-2008	0.0	88.2	L0.5	28.98	62.8	R2	19.31	55.1	R3	9.39
1989-2010	6.4	91.7	L0.5	19.65	66.3	R2	11.14	59.6	R3	3.74
1989-2012	2.4	71.5	L1 *	16.27	57.2	R2.5	5.85	54.7	R3	2.38
1989-2014	5.8	72.0	L1	13.39	59.1	R2	4.45	56.4	R2.5	2.33

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

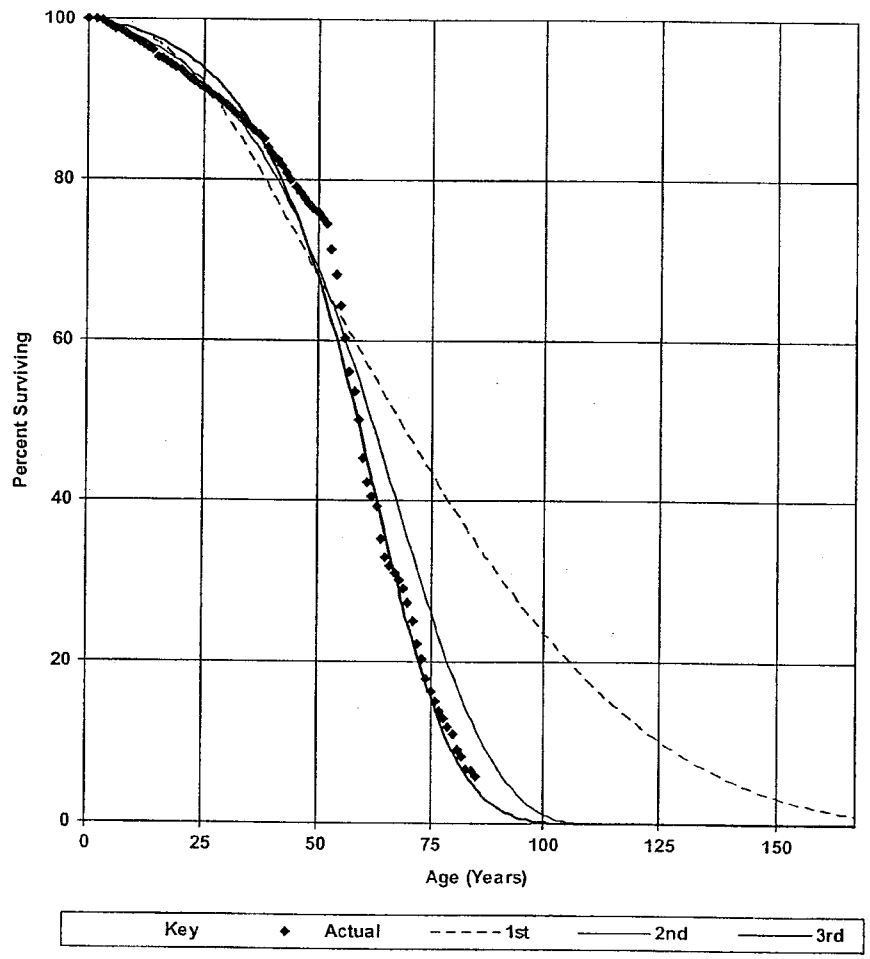
Placement Band: 1926-2014 Observation Band: 1989-2014

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 72.0-L1 2nd: 59.1-R2 3rd: 56.4-R2.5



TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

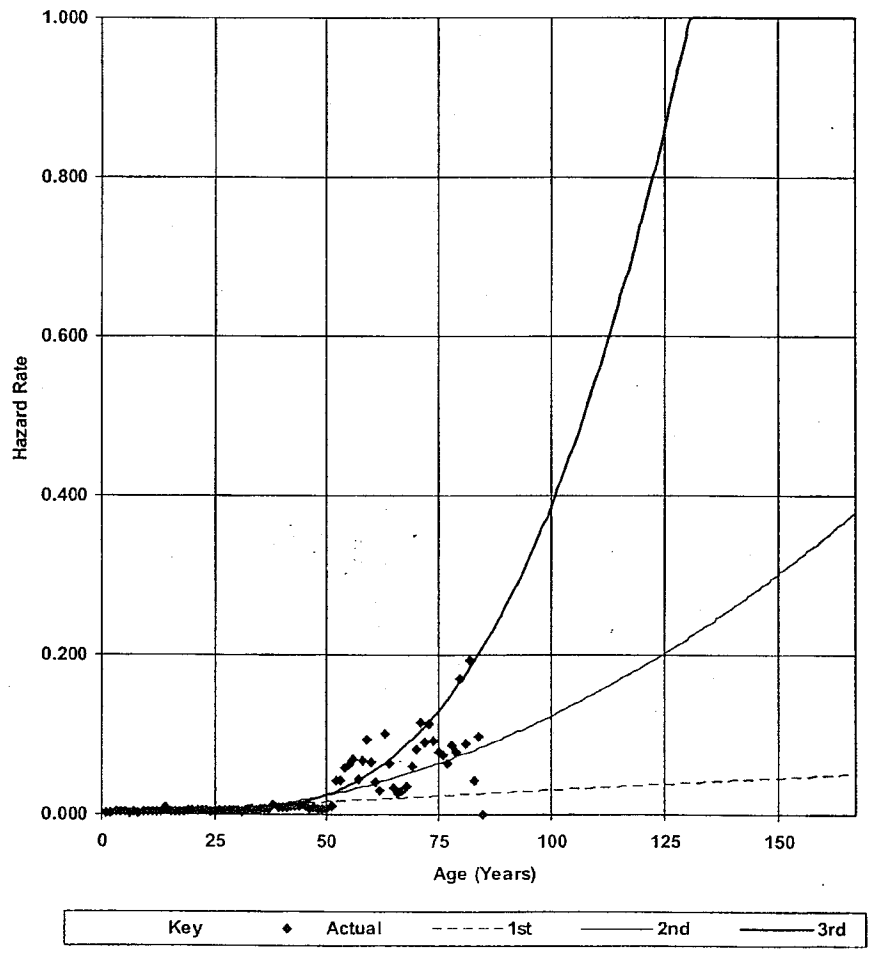
T-Cut: None

Placement Band: 1926-2014 Observation Band: 1989-2014

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function 1st: 72.0-L1 2nd: 59.1-R2 3rd: 56.4-R2.5



TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

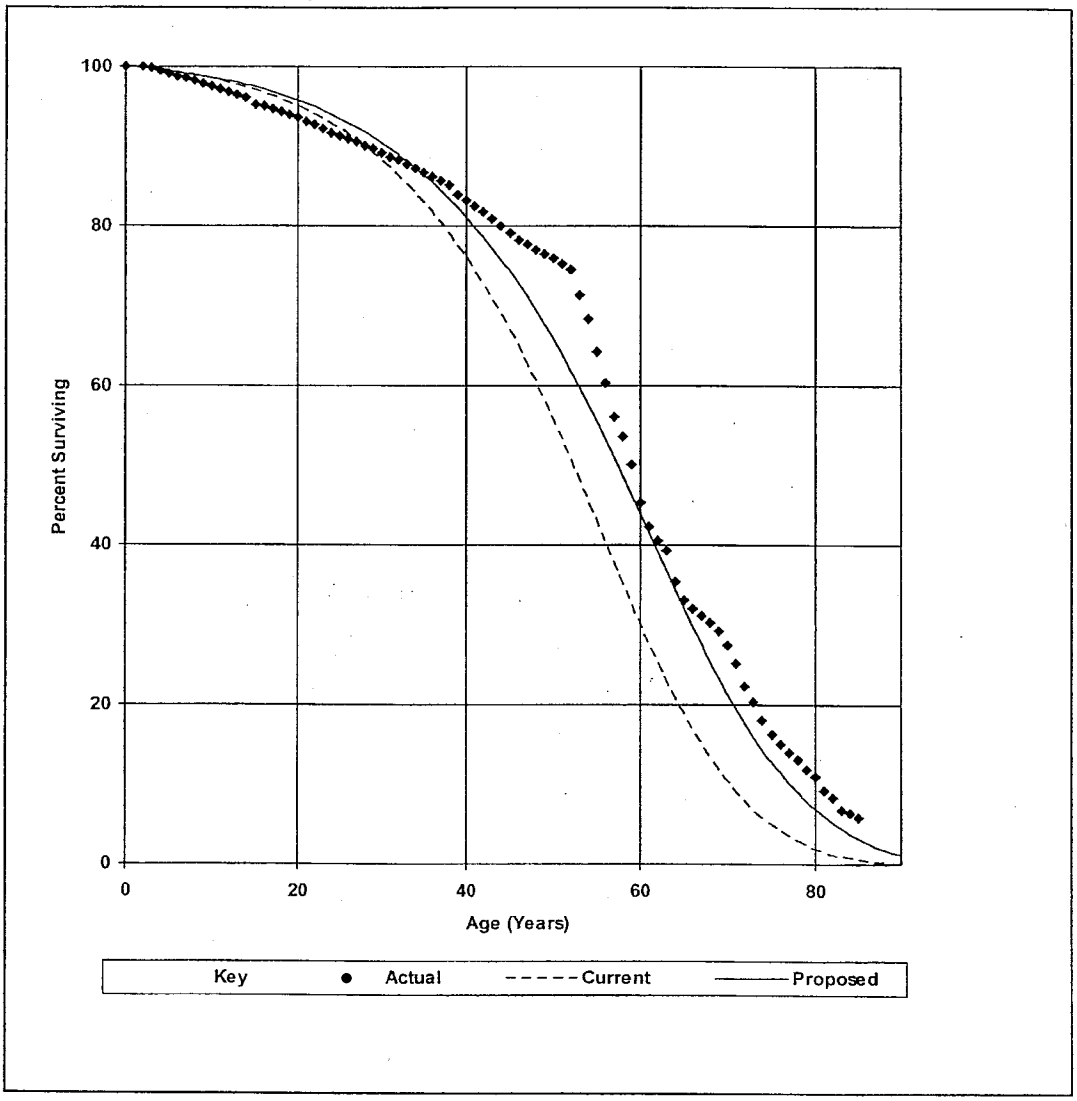
T-Cut: None

Placement Band: 1926-2014

Observation Band: 1989-2014

Current and Proposed Projection Life Curves

Current: 50.0-R2.5 Proposed: 55.0-R2.5



TUCSON ELECTRIC POWER COMPANY

Net Salvage

Account: 108.02 Distribution

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1989	5,361,761	667,990	12.5		785,078	14.6		(117,088)	-2.2	
1990	3,337,683	1,316,905	39.5		1,433,463	42.9		(116,558)	-3.5	
1991	4,251,212	1,256,819	29.6		3,080,152	72.5		(1,823,333)	-42.9	
1992	2,355,616	783,444	33.3		2,189,522	92.9		(1,406,079)	-59.7	
1993	2,169,120	775,288	35.7	27.5	1,572,733	72.5	51.8	(797,445)	-36.8	-24.4
1994	3,641,728	975,582	26.8	32.4	2,389,843	65.6	67.7	(1,414,261)	-38.8	-35.3
1995	3,319,838	979,605	29.5	30.3	1,226,078	36.9	66.5	(246,472)	-7.4	-36.1
1996	2,301,967	997,479	43.3	32.7	1,291,111	56.1	62.9	(293,632)	-12.8	-30.2
1997	2,272,824	671,318	29.5	32.1	1,245,117	54.8	56.4	(573,799)	-25.2	-24.3
1998	1,411,419	545,596	38.7	32.2	944,014	66.9	54.8	(398,419)	-28.2	-22.6
1999	90,038	202,823	225.3	36.2	311,919	346.4	53.4	(109,096)	-121.2	-17.3
2000	3,427,554	819,167	23.9	34.1	(6,212)	-0.2	39.8	825,379	24.1	-5.8
2001	87,700	67,789	77.3	31.6	266,993	304.4	37.9	(199,203)	-227.1	-6.2
2002	1,780,979	549,785	30.9	32.1	401,616	22.6	28.2	148,168	8.3	3.9
2003	1,284,928	514,230	40.0	32.3	209,557	16.3	17.7	304,673	23.7	14.5
2004	10,734,023		0.0	11.3		0.0	5.0		0.0	6.2
2005	3,344,454	2,323,660	69.5	20.1	846,755	25.3	10.0	1,476,905	44.2	10.0
2006	2,636,547	479,963	18.2	19.6	4,691,270	177.9	31.1	(4,211,307)	-159.7	-11.5
2007	4,499,717	1,837,868	40.8	22.9	5,761,426	128.0	51.2	(3,923,559)	-87.2	-28.2
2008	2,105,375	1,465,293	69.6	26.2	1,335,375	63.4	54.2	129,918	6.2	-28.0
2009	(369,286)	1,490,991	-403.7	62.2	930,744	-252.0	111.0	560,247	-151.7	-48.8
2010	6,660,347	1,899,492	28.5	46.2	1,491,496	22.4	91.5	407,996	6.1	-45.3
2011	14,100,108	3,886,122	27.6	39.2	1,954,166	13.9	42.5	1,931,956	13.7	-3.3
2012	32,286,157	3,483,875	10.8	22.3	1,981,445	6.1	14.0	1,502,430	4.7	8.3
2013	30,399,599	3,167,575	10.4	16.8	1,645,569	5.4	9.6	1,522,006	5.0	7.1
2014	35,565,597	3,364,056	9.5	13.3	1,693,337	4.8	7.4	1,670,719	4.7	5.9
Total	179,057,006	34,522,713	19.3		39,672,565	22.2		(5,149,852)	-2.9	

TUCSON ELECTRIC POWER COMPANY

Net Salvage

Account: 108.02 Distribution

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1989	5,398,121	667,990	12.4		785,078	14.5		(117,088)	-2.2	
1990	3,306,759	1,316,905	39.8		1,433,463	43.3		(116,558)	-3.5	
1991	4,249,399	1,256,819	29.6		3,080,152	72.5		(1,823,333)	-42.9	
1992	2,328,078	783,444	33.7		2,189,522	94.0		(1,406,079)	-60.4	
1993	2,370,447	775,288	32.7	27.2	1,572,733	66.3	51.3	(797,445)	-33.6	-24.1
1994	3,669,298	975,582	26.6	32.1	2,389,843	65.1	67.0	(1,414,261)	-38.5	-34.9
1995	2,991,044	979,605	32.8	30.6	1,226,078	41.0	67.0	(246,472)	-8.2	-36.4
1996	2,628,926	997,479	37.9	32.3	1,291,111	49.1	62.0	(293,632)	-11.2	-29.7
1997	2,274,658	671,318	29.5	31.6	1,245,117	54.7	55.4	(573,799)	-25.2	-23.9
1998	2,156,667	545,596	25.3	30.4	944,014	43.8	51.7	(398,419)	-18.5	-21.3
1999	975,061	202,823	20.8	30.8	311,919	32.0	45.5	(109,096)	-11.2	-14.7
2000	4,408,607	819,167	18.6	26.0	(6,212)	-0.1	30.4	825,379	18.7	-4.4
2001	1,245,580	67,789	5.4	20.9	266,993	21.4	25.0	(199,203)	-16.0	-4.1
2002	3,459,416	549,785	15.9	17.8	401,616	11.6	15.7	148,168	4.3	2.2
2003	4,220,779	514,230	12.2	15.1	209,557	5.0	8.3	304,673	7.2	6.8
2004	1,343,658		0.0	13.3		0.0	5.9		0.0	7.4
2005	3,342,122	2,323,660	69.5	25.4	846,755	25.3	12.7	1,476,905	44.2	12.7
2006	2,536,197	479,963	18.9	26.0	4,691,270	185.0	41.3	(4,211,307)	-166.0	-15.3
2007	4,745,873	1,837,868	38.7	31.8	5,761,426	121.4	71.1	(3,923,559)	-82.7	-39.2
2008	2,869,248	1,465,293	51.1	41.2	1,335,375	46.5	85.2	129,918	4.5	-44.0
2009	1,245,916	1,490,991	119.7	51.5	930,744	74.7	92.0	560,247	45.0	-40.5
2010	6,741,625	1,899,492	28.2	39.5	1,491,496	22.1	78.3	407,996	6.1	-38.8
2011	9,584,974	3,886,122	40.5	42.0	1,954,166	20.4	45.6	1,931,956	20.2	-3.5
2012	9,894,066	3,483,875	35.2	40.3	1,981,445	20.0	25.4	1,502,430	15.2	14.9
2013	10,388,388	3,167,575	30.5	36.8	1,645,569	15.8	21.1	1,522,006	14.7	15.7
2014	18,904,562	3,364,056	17.8	28.5	1,693,337	9.0	15.8	1,670,719	8.8	12.7
Total	117,279,470	34,522,713	29.4		39,672,565	33.8		(5,149,852)	-4.4	

Direct Testimony of Frank P. Marino

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01933A-15-_____

Direct Testimony of

Frank P. Marino

on Behalf of

Tucson Electric Power Company

November 5, 2015

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Exhibits

Exhibit FPM-1 Bonus Depreciation Illustration

Exhibit FPM-2 ACC Correspondence regarding Investment Tax Credit

I. INTRODUCTION.

Q. Please state your name and business address.

A. Frank P. Marino. My business address is 88 E Broadway Blvd, Tucson, AZ 85701.

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I serve as TEP's Vice President and Controller. My responsibilities include all accounting, tax, and financial reporting functions at TEP. I serve in the same capacity for UNS Energy Corporation and its subsidiaries.

Q. Please describe your background and work experience.

A. I have 28 years of experience working with electric and gas utilities and power generation companies in accounting, finance, regulatory and general management roles. I hold a Bachelor of Science in Accounting from the State University of New York and a Masters of Business Administration in Finance from Fairleigh Dickinson University. I am licensed as a Certified Public Accountant in New Jersey.

I joined TEP in January 2013 as Assistant Controller and was appointed Vice President and Controller in August 2013. Prior to joining TEP, I was a Vice President at The AES Corporation ("AES") in financial and project management roles, and I also held senior leadership financial roles at its electric utility subsidiary Indianapolis Power & Light Company. Prior to AES, I was employed by Xcel Energy ("Xcel") in its accounting and financial reporting department.

My career began in 1987 with Orange and Rockland Utilities, Inc. ("O&R") where I held progressively expanding roles in financial reporting and regulatory affairs. I ultimately

held the title Director of Compliance when O&R was acquired by Consolidated Edison Company of New York, Inc. ("Con Edison") in 1999. At Con Edison, I held the role of Assistant Controller until I joined Xcel in 2003. While with O&R and Con Edison, I testified in rate case and other regulatory proceedings in New York, New Jersey and Pennsylvania on numerous occasions. In addition, I submitted direct testimony before the Federal Energy Regulatory Commission.

Q. What is the purpose of your Direct Testimony?

A. My testimony is in support of the Company's rate case filing. I am sponsoring the historical information for the twelve month period ending June 30, 2015 (the "Test Year") presented on the following schedules:

- C-3
- E-1 through E-9

I address the early retirement of generation plant assets, and I support in my testimony various pro forma adjustments made to the Test Year on Schedules B-2 and C-2. Specifically, I am sponsoring the rate base pro forma adjustments on Schedule B-2 listed below:

- Sundt Coal Handling Facilities
- San Juan Unit 2
- Sundt and San Juan Materials and Supplies
- Accumulated Deferred Income Taxes ("ADIT")
- Accumulated Deferred Investment Tax Credit ("ITC")
- Fortis Merger Rate Base Adjustment

I am also sponsoring the pro forma adjustments reflected on Schedule C-2 listed below:

- Payroll Expense

- Payroll Tax Expense
- Pension & Benefits
- Post-Retirement Benefits
- Short-Term Incentive Compensation
- Long-Term Incentive Compensation
- San Juan Unit 2 Operating Costs
- Sundt and San Juan Materials and Supplies
- San Juan Unit 1 SNCR O&M Expense
- Depreciation and Amortization Expense Annualization
- Property Tax Expense
- Income Tax Expense
- Fortis Merger Operating Income Adjustment

Finally, I will address the Company's compliance with the Fortis merger conditions.

II. SUMMARY OF SCHEDULES.

A. "C" Schedules.

Q. Please describe the information contained on summary Schedule C-3.

A. Schedule C-3 calculates the revenue conversion factor. That factor is used to convert the computed Test Year return deficiency to an equivalent annual revenue increase amount. It effectively recognizes that there will be additional bad debt expense and income taxes associated with any adjustment to annual revenue requirements.

B. "E" Schedules.

Q. Please summarize Schedules E-1 through E-9.

A. Schedules E-1 through E-9 were prepared in accordance with the filing requirements contained in Arizona Administrative Code ("A.A.C.") R14-2-103. These schedules contain historical financial and accounting information, key operating statistics and notes to the financial statements using information in the Company's regulatory books of account.

Q. Are TEP's regulatory books of account maintained in accordance with the FERC Uniform System of Accounts as required under A.A.C. R14-2-212.G.2?

A. Yes.

Q. Please describe Schedule E-1.

A. Schedule E-1 contains the comparative TEP balance sheets at the end of the Test Year and the two prior periods ended December 31, 2014, and December 31, 2013.

Q. Please describe Schedule E-2.

A. This schedule sets forth comparative income statements for the Test Year and the two prior calendar years. The income statement for the Test Year is the starting point for the Adjusted Test Year income statement shown on Schedule C-1.

Q. Please describe Schedule E-3.

A. This Schedule presents the comparative statements of cash flows for the Test Year and the two prior calendar years.

Q. Please describe Schedule E-4.

A. This Schedule reports the changes in stockholders' equity from December 31, 2012 through the end of the Test Year.

Q. Please describe Schedule E-5.

A. Page 1 of Schedule E-5 presents a summary of the balances in the various electric utility plant account categories and accumulated depreciation and amortization at June 30, 2015 and December 31, 2014. Pages 2 and 3 of Schedule E-5 present the same information on a more detailed basis, by individual electric plant account. Pages 4 and 5 of Schedule E-5 present the balances for acquisition discounts at December 31, 2014 and at the end of the Test Year.

Q. Please describe Schedule E-6.

A. Schedule E-6 contains operating income statements for the Test Year and two previous calendar years. Retail revenues are reported by rate class. Operating expenses are reported by major category.

Q. Please describe Schedule E-7.

A. This Schedule reports key electric operating statistics, in a comparative format, for the Test Year and the two prior calendar years.

Q. Please describe Schedule E-8.

A. This Schedule shows the taxes charged to operating expenses by type for the Test Year and the two prior calendar years.

Q. Please describe Schedule E-9.

A. This Schedule contains a reference to FERC's website for TEP's FERC Form 3-Q for the period ended June 30, 2015 and the FERC Form 1 for the period ended December 31, 2014 which includes the footnotes to the financial statements for the twelve months ended December 31, 2014, the most recent calendar year period for which footnotes were prepared. The footnotes disclose important facts required for a proper understanding of the financial statements.

III. PRO FORMA ADJUSTMENTS.

Q. Please explain what a pro forma adjustment is.

A. Public utility rates are established based on prudently incurred costs of providing safe, reliable service. The Company's revenue requirement is based on a historical Test Year that reflects a level of operating revenues, expenses and net plant investment in that period. Because a historical Test Year is being used, it creates a need to adjust for occurrences not expected to recur or for events that are expected to occur but did not during the Test Year. Such adjustments may be in the form of eliminations, annualizations or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions that are not properly included in Test Year revenue requirements. For example, the Company has eliminated the costs associated with the Fortis merger that were incurred during the Test Year.

Annualization adjustments are made to reflect the full, twelve-month, revenue or expense level of components of operating income. Annualization adjustments recognize that certain events that happen in a Test Year are ongoing and must be spread over the entire

Test Year period. An example of an annualization adjustment is the depreciation expense adjustment to reflect end of Test Year investments. The annualization adjustments synchronize Test Year investments, revenue and expense relationships.

Normalization adjustments reflect that the recorded Test Year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the Test Year may not be viewed as normal thus requiring an adjustment for ratemaking purposes.

IV. GENERATION PLANT EARLY RETIREMENTS.

Q. Did the Commission address early generation plant retirements in TEP's last rate case?

A. Yes. The Settlement Agreement approved in the most recent TEP Rate Order, Decision No. 73912 (June 27, 2013) ("2013 TEP Rate Order"), states at Section 20.3 that "if TEP makes any filing with the ACC related to the early retirement of any production asset, TEP will propose that any then-existing excess depreciation reserve for production plant be applied to the unrecovered book value of the retiring asset."

Q. Is TEP expected to retire early any generation plant assets?

A. Yes. There are two generation stations that will have certain early plant retirements due, in both cases, to environmental regulations. These include the coal handling facilities at H. Wilson Sundt Generating Station ("Sundt") and Unit 2 of the San Juan Generating Station ("San Juan"). These early retirements will be complete by the end of the first

year that new rates are effective as a result of this rate case. I will address each separately.

Q. Please describe the Sundt coal handling facilities.

A. Sundt Unit 4 is a steam generation facility capable of generating electricity from multiple fuels, including coal and natural gas. It is the only unit at Sundt capable of burning coal. The coal related assets include a rail spur, a rotary car dumper, pulverizers, and coal conveyors with a net book value of $16 million as of June 30, 2015. These assets entered service in 1988 and were built in response to a 1981 order of the U.S. Department of Energy requiring the use of coal as the primary boiler fuel at Sundt.

Q. What environmental regulations are causing the early retirement of the Sundt coal handling facilities?

A. There are two regulations related to Regional Haze and mercury emissions that are impacting Sundt. The combination of the Regional Haze and mercury emission rules are causing the early retirement of the coal handling facility assets.

Q. Please describe the Regional Haze Rules requirements related to Sundt.

A. The Environmental Protection Agency's ("EPA") Regional Haze Rules require emission controls known as Best Available Retrofit Technology ("BART") for certain industrial facilities emitting air particulate that reduce visibility in national parks and wilderness areas. The EPA issued a final rule for Sundt that would require TEP to either (i) install, by mid-2017, Selective Non-Catalytic Reduction ("SNCR") and dry sorbent injection at Sundt Unit 4 if it continues to use coal as a fuel source, or (ii) permanently eliminate coal as a fuel source as a better-than-BART alternative by the end of 2017. Under this rule, TEP is required to notify the EPA of its decision by March 2017. Installing SNCR and dry sorbent injection on Sundt Unit 4 is inconsistent with TEP's resource diversification

strategy addressed by TEP witness Hutchens. TEP has exhausted its coal inventory at Sundt and is currently fueling Sundt Unit 4 primarily with natural gas.

Q. Please address the mercury rules as they relate to Sundt.

A. In February 2012, the EPA issued final rules for the control of mercury and other power plant emissions. These rules require additional control equipment that would need to be installed at Sundt by April 2016. Although the U.S. Supreme Court reversed and remanded the mercury rule in June 2015, the rules remain in force and effect. Additionally, Arizona has an Arizona-specific mercury rule in place that will become effective and applicable to Sundt in the event the Federal rule is struck down.

Q. Please summarize TEP's proposal related to the early retirement of the Sundt coal handling facilities.

A. Sundt Unit 4 is capable of burning coal until it can no longer comply with the mercury rules in April 2016. At that time, the coal handling facilities will no longer be used and useful and must be removed from plant in service. As these facilities are still being recovered in TEP's rates, the investment will be transferred to a regulatory asset account and amortized at the same rate it would otherwise have been depreciated as plant in service, until the remaining unrecovered cost is offset against an equivalent amount of the generation depreciation reserve as addressed later in my testimony. Upon approval of this treatment by the ACC, TEP will record the offset of the remaining unrecovered investment against the excess generation depreciation reserve.

Q. Please address San Juan.

A. San Juan is a four-unit coal-fired steam generation facility located in New Mexico and operated by Public Service Company of New Mexico ("PNM"). TEP has a 50% interest in both coal-fired units 1 and 2 each having a nominal capacity rating of 340 MW

resulting in TEP's ownership of 170 MW for each unit.

Q. What environmental regulations are causing the early retirement of assets at San Juan?

A. The same Regional Haze Rules that are causing the early retirement of Sundt coal handling facilities are causing the early retirement of assets at San Juan. In October 2014, the EPA published a final rule approve a New Mexico state plan for San Juan which includes the closure of Units 2 and 3 by December 2017 and the installation of SNCR technology on units 1 and 4 by January 2016.

Given the closure of two units and the desire of certain participants to end their ownership interests in San Juan, PNM and the other owner participants, including TEP, negotiated restructured ownership agreements. As a result, following the closure of San Juan Units 2 and 3, TEP's ownership interest will consist of a 50% interest in San Juan Unit 1.

In August 2015, PNM filed a settlement agreement with the New Mexico Public Regulation Commission ("NMPRC") for approval of the ownership changes and to retire San Juan units 2 and 3 in December 2017. The NMPRC is expected to rule on this settlement agreement in late 2015 or early 2016. TEP's proposed treatment of San Juan Unit 2 in this case assumes NMPRC approval to early retire Unit 2 in December 2017.

Q. Please summarize TEP's proposed treatment of the early retirement of the San Juan Unit 2.

A. Although San Juan Unit 2 is not expected to be retired until the end of the first year that new rates will be in effect as a result of this rate case, TEP proposes to reflect the retirement of the asset consistent with the rate treatment specified for early generation

plant retirements in TEP's last rate case as addressed later in my testimony. I will also address the proposed treatment of capital, spare parts and operating expenses that will be incurred prior to the retirement of the assets.

Q. Are there other costs related to the Regional Haze compliance plan for San Juan that need to be addressed in this case?

A. Yes. The Company proposes pro forma adjustments related to remaining spare parts inventory for San Juan Unit 2 and the operating costs related to the SNCR that need to be reflected in the Test Year operating expenses. In addition, TEP invested approximately $1.7 million in Selective Catalytic Reduction ("SCR") technology based on an initial EPA order requiring the installation of SCR on all four units at San Juan. TEP proposes to record these costs to a regulatory asset for recovery in its next rate base rate case filing.

V. RATE BASE PRO FORMA ADJUSTMENTS.

A. Sundt Coal Handling Facilities.

Q. Please address the rate base pro forma adjustment for Sundt coal handling facilities.

A. TEP is reflecting the early retirement of the coal handling facilities at the Sundt by reducing plant assets for the original book value and correspondingly reducing accumulated depreciation for the equivalent amount. This is an appropriate way of presenting the ultimate disposition of the remaining book value of the Sundt coal handling facilities in this case in accordance with the Settlement Agreement in TEP's last rate case.

Q. What are the impacts of this adjustment?

A. The adjustment results in the elimination of depreciation expense, property tax expense

and any direct costs associated with the coal handling facilities formerly recognized as fuel costs.

B. <u>San Juan Unit 2.</u>

Q. Please summarize TEP's proposed treatment of the expected early retirement of San Juan Unit 2.

A. As addressed earlier in my testimony, San Juan Unit 2 is expected to be removed from service in December 2017. TEP is reflecting its early retirement by reducing plant assets for its book value and correspondingly reducing accumulated depreciation for the equivalent amount. The depreciation rates sponsored by Dr. White do not include depreciation expense for San Juan Unit 2. I would note that Dr. White's depreciation study shows that while there is inadequate excess generation depreciation reserve to cover both Sundt coal handling facilities and San Juan Unit 2, there is a sufficient level of total excess reserves when combining both generation and distribution excess reserves to nearly offset all of these remaining unrecovered costs associated with these assets.

Q. Are there any differences between the rate treatment of San Juan Unit 2 and the Sundt coal handling facilities?

A. Yes. Unlike the coal handling facilities that will be out of service prior to when rates become effective as a result of this case, San Juan Unit 2 will continue to supply system electricity to TEP in 2017. As a result, there will be costs incurred during 2017 including operation and maintenance expenses, capital expenditures, and property taxes that need to be addressed in this rate case.

Q. Please describe how TEP proposes to recover 2017 operating costs of San Juan Unit 2.

A. Since San Juan Unit 2 will continue to be used and useful during the first full year rates are expected to be effective as a result of this case, TEP could include all the costs associated with operating Unit 2 in the Test Year. Accordingly, the Company could benefit from regulatory lag as an offset to its typical adverse impact. However, TEP is not proposing such treatment and is only requesting cost recovery that reflects the anticipated costs for 2017. TEP proposes to include one-third of the 2017 operating cost for San Juan Unit 2 in Test Year expenses based on the assumption that new base rates from this case will remain in effect for approximately three years before TEP's next base rate case. For accounting purposes, TEP will reflect in its financial statements one-third of the 2017 operating costs for San Juan Unit 2 to match the revenue allowance and defer the remaining two-thirds of the 2017 operating costs which will then be amortized over the subsequent two year period.

Q. Please describe how TEP proposes to recover any post Test Year capital costs related to San Juan Unit 2.

A. TEP is requesting to record post Test Year capital costs related to San Juan Unit 2 as a regulatory asset for inclusion in its rates at TEP's next rate case.

Q. Are there benefits to customers by reflecting the retirement of San Juan Unit 2 in this proceeding in the manner proposed by TEP?

A. Yes. Base rates will be reflect a lower level of recovery for operation, maintenance and depreciation expense as proposed due to pro forma Test Year costs that are less than actual costs incurred in the Test Year.

C. Sundt and San Juan Materials and Supplies.

Q. Please address the treatment of any remaining materials and supplies for Sundt coal handling facilities and San Juan Unit 2.

A. TEP proposes to record any remaining inventory related to the Sundt coal handling facilities and San Juan Unit 2 to a regulatory asset and amortize the cost over a three year period starting in the Test Year. The inventory specific to the coal handling facilities will no longer be necessary once a decision is made to no longer burn coal at the Sundt Unit 4. Those items were purchased to assure the continued service of Unit 4 and, had they been installed, would have been recovered as depreciation expense charged to fuel. This adjustment will also include any remaining San Juan spare parts inventory after assessing what inventory from Unit 2 can be utilized at Unit 1 which will remain in operation, as the units consist of similar technology.

D. Accumulated Deferred Income Tax ("ADIT").

Q. Please explain what ADIT is.

A. ADIT represents the balance of deferred income taxes recorded over time based on the difference between when an item of income or expense is recognized for financial reporting purposes and when it is recognized for income tax purposes. There are many items that are subject to such timing differences, however, the most significant differences arise from the accelerated depreciation methods used for income tax purposes.

Q. Can you provide an example of how deferred income taxes arise?

A. Yes. Let's assume that TEP makes a $1 million investment in a distribution line that is placed in service in 2015 and has a 40-year straight-line depreciable life for financial

reporting purposes. For simplicity, I will ignore cost of removal and salvage values and assume that the investment qualifies for 100% bonus depreciation for tax purposes. The distribution line's book depreciation rate would be 2.5% and TEP's electric rates would be set to recover $25,000 in depreciation expense per year for 40 years. For tax purposes, however, the entire investment in the line would be deducted in the year it is placed in service. Thus, in 2015 TEP would collect $25,000 of taxable revenue and claim tax depreciation of $1 million. As a result, TEP would have a net depreciation timing difference of $975,000 which, when it offsets TEP's other taxable income, would produce an incremental cash benefit as a reduction in income taxes paid of $341,350 assuming a 35% Federal income tax rate ($975,000 x 35%).

The $341,250 cash benefit to TEP represents funds available to finance utility operations. However, the cash will need to be repaid to the government over time as the depreciation timing difference for the distribution line reverses. In effect, the accelerated depreciation for income tax purposes gives rise to an interest-free loan from the government. This timing difference results in an ADIT balance of $341,350 at the end of 2015, which is deducted from rate base.

Q. Please describe how deferred income tax balances for the distribution line reverse.

A. In each of the next 39 years, TEP will collect $25,000 of depreciation expense from its customers which will be taxable for income tax purposes. However, since the entire investment in the line was deducted in 2014 for tax purposes, TEP has $0 tax depreciation to claim for the remaining life of the line. Thus, TEP will include on its tax return $25,000 of taxable income upon which it will incur $8,750 of income tax ($25,000 x 35%). This difference between book depreciation and tax depreciation will result in an annual reduction in ADIT of $8,750 per year until the $341,250 ADIT balance in 2015 is fully amortized in year 40 ($8,750 x 39 = $341,250).

Q. Please explain the ADIT Adjustment.

A. The adjustment reduces rate base for the computed balance of ADIT. A rate base deduction is appropriate to reflect the interest free source of capital for timing differences reflected in rate base (e.g., accelerated tax depreciation on plant in service, whether through regular or bonus depreciation) consistent with the Commission's historical normalization rate treatment for TEP which I will address later in my testimony. As a result of this rate base deduction, the customer is not paying a rate of return on the interest free source of capital.

Q. In order to better understand deferred income taxes, can you briefly describe the accounting for income taxes under GAAP?

A. Yes. Accounting for income taxes under GAAP is contained in the Accounting Standards Codification ("ASC") in Section 740 (formerly SFAS No. 109 *Accounting for Income Taxes* ("SFAS109")). The income tax calculation has three components: income taxes currently payable, deferred income taxes, and deferred investment tax credit ("ITC"). Taxes currently payable represents the income taxes payable to the U.S. Treasury for the current period as computed under the provisions of the Internal Revenue Code ("IRC"). There are differences between how certain items are treated under the IRC and GAAP. These differences are listed on Schedule M of the filed income tax return. Such differences between income tax treatment and book accounting treatment are either timing differences or permanent differences.

As I stated earlier, the most common and largest timing difference is depreciation. Depreciation is a timing difference because both book and tax depreciation amounts are limited, over time, to the cost of the utility plant. Thus, in the early years tax depreciation will exceed book depreciation, but in the later years, book depreciation will exceed tax depreciation.

Other examples of timing differences include: (i) expenses that are deducted by utilities currently for tax purposes, but deferred on the books as regulatory assets for future recognition in rates (such as rate case expense); and (ii) expenses that are recognized for book purposes ahead of when they are deductible for income tax purposes (such as accrued vacation expense).

Permanent differences also exist between book income and taxable income, and do not reverse in subsequent periods. Examples of permanent differences include non-taxable interest income from municipal bonds and meals expense, which is only 50% deductible for income tax purposes. Both of these items are included when determining book income, but are never included in the determination of taxable income on the income tax return.

Q. How are the income tax components calculated?

A. Income taxes currently payable are calculated on the liability incurred by the Company based on the current year's taxable income using the rules under the IRC. Deferred income taxes are computed for timing differences, but not for permanent differences. Deferred income tax expense is calculated by multiplying timing differences by the statutory income tax rates in effect at the time the timing difference reverses. It should be noted that the typical effect of timing differences is to reduce current income taxes and increase deferred income taxes, dollar for dollar with no "net" impact on the calculation of total income tax expense.

Q. How do deferred income taxes affect public utility rate-making?

A. The reflection of deferred income taxes in rate-making is commonly referred to as normalization. Some utility regulatory agencies permit utilities to recognize deferred income taxes associated with all timing differences in rate-making ("full normalization"),

while others only permit the recognition of certain timing/temporary differences required by the IRC to be recognized in utility ratemaking ("partial normalization"). To the extent that normalization is permitted in ratemaking, the resulting deferred income taxes are reflected as a component of income tax expense – with the corresponding balance sheet reserve for accumulated deferred taxes deducted from rate base as non-investor capital. This treatment reflects the availability of such amounts for plant investment or operating purposes between the time they are collected from customers and ultimately remitted to taxing authorities.

The other ratemaking approach to timing differences is when regulators do not permit deferred income tax expense as a recoverable cost in the ratemaking process. This approach is known as flow through since, under this approach, the income tax reducing benefits of tax return deductions are flowed-through to the retail customer by a reduction of current income tax expense, without the offsetting deferred income tax expense. Because flow-through only applies to book-tax timing differences, any reduction in income taxes payable when a timing difference originates is offset by higher income taxes payable when the timing difference reverses. Of course, under a flow-through approach, there is no ADIT to reduce rate base as the interest-free loan has been provided to retail customers.

Q. What income tax rate-making authority has been granted to TEP?

A. Prior to 1979, TEP was a flow-through entity for ratemaking purposes, meaning that it was not permitted to reflect deferred income taxes in rate-making. In Decision No. 50430 (1979), the Arizona Corporation Commission ("Commission" or "ACC") authorized the Company to begin rate recovery of deferred income taxes relating to the benefits (shorter lives and accelerated methods) of accelerated depreciation, starting with production plant placed in service during 1979, transmission plant installed in 1980, and

distribution plant added in 1981. Then, the Commission issued Decision No. 56659 (October 24, 1989), which expanded the Company's normalization authority prospectively to include all originating book-tax timing differences. The Commission ruled that "we will allow full tax normalization at this time." (Decision No. 56659 at 38). This authority included the differences between the manner in which salvage and removal costs are recognized for book and tax purposes, as well as the effect of the debt component of the Allowance for Funds Used During Construction ("AFUDC") and taxable Contributions in Aid of Construction. In Decision No. 58497 (January 13, 1994) at 95, the Commission authorized TEP to implement *SFAS No. 109* (now known as ASC740), for regulatory accounting purposes.

To the extent ASC740 requires the recording of certain deferred tax assets that do not actually reflect the prepayment of tax and certain deferred tax liabilities that do not represent the collection of taxes prior to their remittance to taxing authorities, we effectively exclude these amounts recorded on the Company's balance sheet in determining the appropriate amount of deferred tax assets and ADIT for ratemaking purposes. An example of this treatment is the equity component of AFUDC. The equity component of AFUDC is capitalized for book purposes but is excluded from our income tax return. Under ASC740, the amount capitalized for books (the amount capitalized in the work order and depreciated) compared to the amount capitalized for income tax purposes (zero) represents a temporary difference that requires ADIT. For book purposes, we offset the ADIT on the equity component of AFUDC with a regulatory asset, thus recognizing we have not included such amounts on the tax return.

Q. Has there been a substantial change in ADIT since TEP's last rate case?

A. Yes. TEP's last rate case used a test year ending December 31, 2011. Since the last test year, the ADIT relating to accelerated depreciation has increased as a result of recent

bonus depreciation legislation. On January 3, 2013, the "American Taxpayer Relief Act of 2012" was passed extending 50% bonus depreciation through December 31, 2013. On December 22, 2014, the "Tax Increase Prevention Act of 2014" was passed extending 50% bonus depreciation through December 31, 2014. At the time of this filing, Congress has not acted to further extend bonus depreciation beyond December 31, 2014.

Q. Did TEP elect bonus depreciation on all eligible property placed in service since the last rate case?

A. Yes. TEP has claimed bonus depreciation on all eligible assets since the last rate case.

Q. Is bonus depreciation beneficial to customers?

A. Yes. By claiming bonus depreciation, TEP ensures that it receives the maximum amount of interest-free capital on behalf of its customers, therefore it results in the maximum amount rate base deduction. To illustrate this, using the same $1 million distribution line assumptions I discussed earlier, and a 7.34% return on rate base, the customer benefits are over $200,000 larger by claiming bonus depreciation over the regular tax depreciation schedule. See **Exhibit FPM-1**.

Q. Did all of the bonus depreciation deductions result in a cash benefit to TEP through reduced Federal income tax payments?

A. No, not yet. The deductions for bonus depreciation exceeded the amount that could be used to offset taxable income and have created a Net Operating Loss Carryforward (NOLC).

Q. Please explain the concept of NOLC.

A. In comparison to my previous example of the distribution line, a NOLC reflects a loan that has not been made to the Company. A NOLC is recorded as an asset balance in the

deferred income tax accounts. The cash benefit of the loan will be realized when the NOLC is used against a future year's taxable income.

TEP's ADIT balance represents the tax benefits of all timing differences regardless of whether or not they have produced a cash benefit. Therefore, when there is a NOLC, the ADIT credit balance overstates the amount of the interest-free loan made to the Company. These deductions did not defer any Federal income tax liability and thus, under the tax depreciation normalization rules of IRC §168, such excess deductions should not be included in the Company's deferred income taxes.

Q. What are the tax depreciation normalization rules?

A. The tax depreciation normalization rules were enacted by Congress to prevent accelerated tax depreciation incentives from being flowed directly to customers through the rate setting process. The normalization rule requires that, where a utility claims accelerated depreciation it must make an adjustment to a reserve to reflect the amount of deferral of Federal income tax liability resulting from the use of such a depreciation method. In addition, the utility's ADIT that can reduce rate base cannot exceed the amount of such reserve (i.e., resulting from that adjustment) used in computing a utility's cost of service in ratemaking. By excluding the bonus depreciation deductions that were not used to offset taxable income from the computation of deferred income taxes, TEP is in compliance with the normalization rules.

Q. Why doesn't Congress allow the flow-through of accelerated tax depreciation incentives?

A. Accelerated depreciation was enacted for the purpose of promoting investment in plant and equipment by businesses. Congress was concerned that, in the case of regulated utilities whose rates are set by reference to their costs, these incentives could be flowed

directly to customers through the rate-setting process. If this were to occur, then the benefits Congress had intended to promote investment by businesses in plant and equipment would be taken from them and converted into consumption incentives for regulated utility customers. As this was not Congress' intent, it included the depreciation normalization rules in the tax law to prevent this from happening.

Q. What is the impact to TEP and its customers if the tax depreciation normalization rules are not followed?

A. If the normalization rules are not followed, TEP would be unable to claim accelerated tax depreciation. Instead, the Company would be required to use regulatory depreciation methods for tax purposes. This would cause a substantial increase in TEP's income tax payable and a substantial decrease in the ADIT balance that is included as a reduction to rate base. As a consequence, TEP customers benefit when normalization rules are followed.

Q. Has the IRS ruled on the normalization rules when a company has a NOLC?

A. Yes. In Private Letter Rulings (PLRs) 201438003, 201436037, 201436038, 201519021, and 201534001 the IRS ruled that a reduction of a taxpayer's rate base by the full amount of its ADIT balance unreduced by the balance of its NOLC ADIT would be inconsistent with the normalization rules.

Q. Has TEP reduced its ADIT rate base reduction by its NOLC ADIT?

A. Yes. To be consistent with the normalization rules TEP has offset its ADIT rate base reduction by its NOLC ADIT.

Q. What other deferred tax assets not attributable to timing differences have you included in rate base?

A. Similar to the ADIT associated with NOLs, we have also included in rate base the deferred tax asset for Minimum Tax Credit Carryforwards ("MTCC").

Q. What is a MTCC?

A. TEP incurred alternative minimum tax ("AMT") in a number of years. AMT is an amount of tax imposed on a taxpayer over and above its "normal" income tax. The payment of AMT gave rise to a MTCC. MTCCs are credits that can be used to reduce a company's future tax liability. This system of tax effectively reduces the cash benefit of certain tax deductions in the year that they are claimed but, through the MTCC feature, permits that benefit to be realized at a later point in time. The economics of the AMT regime are very similar to those of an NOLC and, as a result, are properly treated in the same fashion.

Q. Generally, how does the AMT work?

A. The AMT rules provide that each corporation adjust its regular taxable income for a number of adjustments and preferences to arrive at alternative minimum taxable income ("AMTI"). A tentative AMT ("TAMT") is computed by applying the 20% AMT tax rate to AMTI. To the extent that this TAMT exceeds the corporation's tax computed in the regular way, it pays the regular tax and an amount equal to the excess. This excess is the AMT. The amount of AMT paid in any year is generally creditable against a corporation's tax liability in future years, but only to the extent that its regular tax exceeds its TAMT in that subsequent year.

Q. What adjustments and preferences are most relevant to TEP?

A. Accelerated depreciation and amortization.

Q. Please provide a simple example of how the AMT operates.

A. Assume TEP, in year 1, has $1 million of pre-tax book income and $900,000 of tax depreciation in excess of book depreciation. TEP reports regular taxable income of $100,000 ($1 million of book income less $900,000 of accelerated tax depreciation) and, assuming a 35% tax rate, incurs a regular tax liability of $35,000. The $900,000 of accelerated depreciation reduces TEP's tax liability by $315,000 ($900,000 x 35%). Thus, TEP has $315,000 of cost-free capital available to it before considering any effects of the AMT. This amount would be reflected as an ADIT credit that is available to reduce rate base.

Q. How does AMT impact TEP's tax liabilities?

A. Assume that TEP has an AMT adjustment which reduces accelerated depreciation deductions by $500,000. AMTI is computed by adding regular taxable income of $100,000 to the amount of the adjustment of $500,000 to produce AMTI of $600,000. At the 20% AMT rate, TEP's TAMT will equal $120,000. Since that amount exceeds its $35,000 regular tax liability, TEP will incur both the $35,000 regular tax liability and $85,000 more in AMT, or a total of $120,000. This $85,000 AMT produces a MTCC which is available to offset taxes payable in the future. Due to the AMT, TEP did not realize the entire $900,000 benefit of its accelerated depreciation. The AMT caused a portion (i.e., $85,000) of the benefit to be deferred until such time as the MTCC is used.

Q. How does TEP reflect AMT on its balance sheet?

A. TEP reflects the full, pre-AMT benefit of the accelerated depreciation ($315,000 in the above example) as a deferred tax credit (*i.e.*, a governmental loan) in FERC Account 282. It then reflects the $85,000 benefit reduction as a deferred tax debit (*i.e.*, a future tax benefit) in FERC Account 190.

Q. What is the amount of cost-free capital available to TEP in the example above?

A. As a result of the AMT benefit reduction, TEP has only $230,000 of cost-free capital available to it. Reducing rate base by $315,000 overstates the amount of the governmental loan. The rate base reduction, in this example, should be $230,000. This is precisely how TEP reflected its MTCC in this proceeding.

Q. What gives rise to the Accumulated Deferred Income Tax Liability for Excess Deferred State Income Taxes ("EDIT") that is included in ADIT?

A. On February 17, 2011, the Arizona legislature passed a bill reducing the state corporate income tax rate from the then effective rate of 6.968% to an ultimate rate of 4.9%. This reduction is being phased in beginning in 2014 with a reduction of approximately 0.5% per year until the income tax rate reaches 4.9% for 2017 and later years.

In 2013, New Mexico adopted similar legislation which reduces the then effective rate of 7.6% to an ultimate rate of 5.9%. The reduction is being phased in beginning in 2014 with a reduction of approximately 0.3% per year until the income tax rate reaches 5.9% for 2018 and later years.

For purposes of ADIT presented in this case, the balance of Arizona deferred income taxes is presented at the rates in effect at the time the timing differences originated.

Q. How does TEP treat the EDIT collected in prior years for ratemaking purposes?

A. The EDIT is amortized as a reduction to deferred income tax expense as the underlying timing differences reverse.

Q. Is the treatment of ADIT and including the impact of NOLC, MTCC and EDIT you are proposing in this case consistent with the treatment approved in TEP's last rate case?

A. Yes.

E. <u>Accumulated Deferred Investment Tax Credit ("ITC").</u>

Q. You previously mentioned a third tax component to the income tax calculation, Accumulated Deferred ITC. Please explain the adjustment for Accumulated Deferred ITC.

A. Unlike deferred taxes, which can be likened to an interest-free loan from the U.S. Treasury, the ITC can be likened to a grant or rebate. The ITC is a direct reduction of income taxes otherwise payable. It is calculated by multiplying a qualifying investment times a statutory credit percentage.

As explained below, for rate-making purposes TEP shares the ITC in accordance with IRC §46(f)(1), whereby the rate-making treatment for Accumulated Deferred ITC is a reduction to rate base that reflects the provision of non-investor capital due to a reduction in income taxes payable (benefitting the customer) with below-the-line amortization (benefitting the shareholder) each year. TEP has claimed ITC under IRC §48(a)(2) that provides for a 30% ITC for investment in qualifying solar facilities placed in service prior to January 1, 2017. Further, IRC §50(c)(3)(A) requires that the depreciable tax basis of the underlying property be reduced by an amount equal to 50% of the energy credit taken with regard to the property.

Q. What are the rules governing the accounting for ITC for public utilities?

A. The tax normalization rules are contained in IRC §46(f) (as in effect prior to the Revenue Reconciliation Act of 1990). IRC §50(d)(2) requires that these normalization rules be applied to the §48 Energy Credit when elected by a regulated utility. The normalization rules require all public utilities to elect one of the two available normalization methods. The method used by TEP is described in §46(f)(1) (as in effect prior to the Revenue Reconciliation Act of 1990).

Q. Please explain the requirements of IRC §46(f)(1).

A. This section provides that a regulated utility shall not reduce the base to which rate of return is applied by any portion of the credit unless the reduction is restored not less rapidly than ratably. "Ratably" is defined as the life used by the public utility for purposes of calculating book depreciation for the qualified property.

Q. How do the normalization rules apply to taxpayers that have generated ITC, but have not yet realized the ITC benefit through lower income tax payments?

A. PLR 8326081 addresses the issue of when the benefits of ITC should be reflected in rates and concluded that if the ITC is used to reduce revenue requirements before actually realized on the income tax return, a normalization violation would occur. While this ruling is for a utility that elected the ITC sharing method provided for in §46(f)(2) (ratable amortization in cost of service), similar guidance should apply for utilities who elected to share ITC under §46(f)(1). In this ruling, the IRS clearly states "the credit cannot be used to reduce the cost of service until it has been allowed for federal income tax purposes". Thus, the taxpayer was prohibited from reducing cost of service for ratemaking purposes. In the case of a company subject to the normalization provisions of §46(f)(1), such as TEP, the same rule would apply to prohibit the reduction of rate base for credits not yet realized on the taxpayer's federal tax return.

Q. What is the amortization period used by TEP to amortize ITC?

A. TEP amortizes the ITC over the tax life of the assets that generated the ITC. This treatment was authorized by the Commission Director of Utilities in a letter to TEP dated July 21, 1983 (attached as Exhibit FPM-2). In the case of solar generating facilities, the property is classified for depreciation purposes in IRC §168(e)(1) and qualifies for a five-year life for tax depreciation purposes. As the book life of the solar generating assets proposed in this case is 28 years, the use of the shorter life is in compliance with the normalization provisions of IRC §46(f)(1).

Q. How is ITC amortization computed?

A. In accordance with the amortization period granted TEP in **Exhibit FPM-2**, the credits are amortized over the tax life of the qualifying property. Since the five-year tax depreciation recovery period authorized by IRC §167 is spread over six years, TEP uses a straight-line amortization period of six years with a half-year of amortization in the first and last years.

Q. Please discuss the ITC that TEP has generated and whether it has been realized.

A. The ITC that TEP has generated is attributable to qualified solar facilities placed in service from 2010-2014. The ITC related to 2010 and 2011 was realized and has been included as a reduction to rate base, net of accumulated amortization. The ITC generated from 2012-2014 has not been realized and consistent with the normalization rules is not included as a reduction to rate base.

Q. Is there a corresponding adjustment to current or deferred income tax expense as a result of the ITC?

A. Yes, there is an adjustment to deferred income tax expense as a result of the ITC discussed later in my testimony.

Q. Is the treatment of ITC in this case consistent with that approved by the ACC in TEP's last rate case?

A. Yes.

F. Fortis Rate Base Adjustment.

Q. Please explain the Fortis Rate Base Adjustment.

A. On August 12, 2014, the Commission issued an order that approved the merger of UNS Energy with Fortis Inc. (Decision No. 74689). A condition of the order specifies that no merger-related cost would be borne by the ratepayers. This adjustment eliminates all merger-related cost allocated to TEP and included in plant in service through overhead allocations. Specifically, this adjustment removes the portion of merger-related costs that were capitalized as part of the Administrative & General loading applied to capital projects.

VI. OPERATING INCOME PRO FORMA ADJUSTMENTS.

A. Payroll Expense.

Q. Before addressing the specific compensation-related pro forma adjustments, please describe the Company's overall employee compensation strategy.

A. The Company has a balanced total compensation program that incorporates performance-based elements for all non-union employees. The Company's compensation policies include the following objectives:

- Attracting, motivating and retaining highly-skilled employees;
- Linking the payment of compensation to the achievement of short and long-term financial and strategic objectives, including providing safe, reliable and affordable electric service; and

- Aligning performance objectives of executive management with those of other employees by using similar performance measures for each group.

The table below summarizes the three components of the total compensation program for non-union employees.

Compensation Component	Key Features	Purpose
Base Salary	Adjustments made annually based on market data and to remain near the median of relevant market data	Provide a fixed amount of compensation
Short-term Incentive Compensation (Performance Enhancement Plan or "PEP")	Goals are identical for executive and non-union employees; Must achieve a minimum threshold of financial performance or payout for other measures capped at 50%.	Motivate and reward achieving or exceeding the Company's short-term objectives, while reinforcing pay-for-performance; Focus employees on key customer, operational and financial metrics.
Long-term Incentive Compensation[1]	Delivered in a combination of performance shares and restricted stock units	Supports retention and ensures focus on long-term performance objectives

Q. How does the Company ensure that total non-union compensation levels are reasonable?

A. With respect to non-executive employees, the Company periodically commissions market studies for a sampling of jobs in order to ensure that total compensation (i.e., the sum of base salary, short-term incentive and long-term incentive compensation) is near the median. For executive management, the Company has established a peer group of other electric and gas utility companies of comparable size and complexity, including electric

[1] Only executive officers and senior director employees are eligible for Long-Term Incentive Compensation.

and gas utility companies thought to be competitors for talent. Total compensation for executive management is similarly targeted at median of market, in this case using a peer group. These approaches enable the Company to successfully hire, motivate and retain talented employees and executives while ensuring a reasonable overall compensation cost structure relative to market.

Q. How does the Company ensure that union employee compensation levels are reasonable?

A. The Company's union employees are represented by a local union which bargains with the Company on wages, benefits and other work related matters on behalf of the represented employees. The Company and the union periodically negotiate Collective Bargaining Agreements that are subject to ratification by the union members. Thus, there is an established process in place to ensure the reasonableness of union employee compensation.

Q. Please explain the Payroll Expense Adjustment.

A. The Payroll Expense Adjustment is necessary to reflect the proper level of salaries and wages in Test Year operating expenses. The Payroll Expense Adjustment was computed based on an average of operations and maintenance ("O&M") wages for the 12 month periods ended June 30, 2015 and June 30, 2014, and reflects the known and measurable wage increase for 2016 and the estimated wage increase for 2017, the year in which rates established in this proceeding will go into effect.

Q. Does the Payroll Expense Adjustment exclude capitalized payroll costs?

A. Yes. The adjustment only includes the amount directly recorded to O&M expenses and excludes the A&G labor cost allocated to capital projects.

Q. Is the Payroll Expense Adjustment consistent with the 2013 TEP Rate Order?

A. Yes.

B. <u>Payroll Tax Expense.</u>

Q. Please explain the Payroll Tax Expense Adjustment.

A. The Payroll Tax Expense Adjustment reflects the Company's taxes (Social Security and Medicare) that correspondingly increase as a result of the increased expense from the Payroll Expense Adjustment. The Company's effective employer's tax rate for 2015 was applied to the increased payroll expense reflected in the Payroll Expense Adjustment.

C. <u>Pension and Benefits.</u>

Q. Please explain the Pension and Benefits adjustment.

A. The Pension and Benefits adjustment is intended to include in operating expenses a level of pension and benefits expense reflecting the Test Year work force and the current pension and medical, dental, vision, life and long-term disability benefit expense level. The benefit costs covered by this adjustment include the qualified retirement pension plans as determined in the most recent actuarial study, the Company's share of contributions to the employees' 401(k) plan, and medical, dental, vision, life and long-term disability costs. The adjustment includes the current cost of the Supplemental Executive Retirement Plan ("SERP") for the Company's executives. The SERP is a normal and recurring business practice.

Q. What is the purpose of a SERP?

A. The qualified pension retirement plan, which covers all TEP employees, is subject to IRC limitations on the amount of compensation that can be taken into account on the amount

of benefits that can be provided. The non-qualified SERP provides the retirement benefits to executive officers that would have been provided under the qualified retirement plan had the limitations not applied.

Q. Is the Pension and Benefits adjustment consistent with the 2013 TEP Rate Order?

A. The pension adjustment, except for the SERP, was prepared and calculated in the same manner as was approved by the Commission as part of the Settlement Agreement in the last TEP rate case. Although the Company did not request recovery of SERP costs in the last rate case, it reserved the right to request it in this rate case.

Q. Why should the revenue requirement in this case reflect the cost of the SERP?

A. Because it is a common business practice and is necessary to keep TEP competitive in attracting and retaining executive talent.

D. <u>Post-Retirement Benefits.</u>

Q. Please explain the Post-Retirement Benefits adjustment.

A. The Post-Retirement Benefits adjustment is necessary to reflect in operating expenses a level of Post-Retirement Benefits expense reflecting the Test Year work force level and the current Post-Retirement Benefits actuarial expense level. In addition, the adjustment includes a component for the 15-year amortization of incremental expense representing the difference between accrual expense and cash cost basis that was recorded between the time when TEP adopted accrual accounting of Post-Retirement Benefits expense for financial reporting purposes and the time when accrual based expense was recognized for ratemaking purposes.

Q. Please explain the change to accrual accounting and the 15-year amortization of the incremental expense.

A. In January 1993, TEP adopted Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions ("FAS 106")*, which requires accrual based accounting, for financial reporting purposes. However, the Commission continued to allow only cash basis recovery for ratemaking purposes until 2008 (Decision No. 70628). The Post-Retirement Benefits adjustment includes a 15-year amortization of the incremental expense incurred by using the cash basis for ratemaking between 1993, when the company adopted FAS 106, and 2008 when the Commission allowed a change to accrual basis for ratemaking purposes. Since Decision No. 70628, TEP's rates have been set to recover Post-Retirement Benefits costs on an accrual basis, including a 15-year amortization of the incremental difference.

Q. Is the Post-Retirement Benefits adjustment consistent with the 2013 TEP Rate Order?

A. Yes.

Q. Is the treatment of the 15-year amortization consistent with the 2013 TEP Rate Order?

A. Yes.

E. <u>Short-Term Incentive Compensation.</u>

Q. Please Explain the Company's Short-Term Incentive Compensation program.

A. The Company's short-term incentive compensation, called the Performance Enhancement Plan ("PEP"), is a program that holds a portion of non-union employee's total cash compensation "at risk". As such, a percentage of a non-union employee's base salary is

linked to the Company's performance. As a performance-based component of total compensation, PEP links compensation to metrics and outcomes that benefit customers in the areas of reliability, safety, customer satisfaction, and financial performance which ultimately benefits customers through lower rate levels. The same metrics are used to determine incentive compensation payouts for non-executive employees and executive management.

Q. How is the "at risk" portion of an employee's compensation determined?

A. The "at risk" portion is reflected as a percentage of base salary depending on an employee's position in the Company and their ability to influence the metrics and outcomes. Performance targets are established each year, typically before the end of the first quarter. The objectives are tailored to drive behavior that supports the Company's strategy for delivering safe and reliable service to customers at reasonable rates while maintaining the financial health of the Company.

Having an "at risk" component of compensation allows the Company to focus its effort toward achieving measurable, meaningful goals and compensating employees when those goals are met. The 2015 PEP goals are as follows:

Metric	Criteria	Weighting	Benefit to Customers
Net Income	Actual Net Income	40%	Efforts to increase net income result in lower rates
Operation and Maintenance ("O&M") Expenses	Actual O&M expense	20%	Lower O&M expense which results in lower rates
Equivalent Availability Factor ("EAF")	Percentage of time that a generation unit is available to provide power at its maximum rating	10%	Increased generation reliability which reduces purchased power costs
System Average Interruption Duration Index ("SAIDI")	Average number of minutes of interruption experienced by customers	10%	Reduced length of outages
Customer Satisfaction	As measured by J.D. Power surveys	10%	Increased customer satisfaction
OSHA Recordables	OSHA Recordable Incident Rate	10%	Improved employee, customer and community safety

The 2014 PEP goals had similar metrics and weightings.

Q. How does the customer benefit from PEP?

A. There are clear benefits to customers through improved reliability, satisfaction, safety and financial performance that ultimately results in lower rates. Moreover, using an incentive compensation program is less costly than higher base salaries because incentive compensation does not automatically drive increases in other employee costs such as: vacation pay, sick pay, long-term disability and 401(K) employer matching contributions. As a result, PEP is less costly than increasing base salaries.

Q. How does a Net Income goal benefit customers?

A. A net income PEP goal places an emphasis on revenue generation and cost reduction efforts. TEP actively seeks out opportunities to increase non-jurisdictional revenues (e.g., long-term wholesale sales) which allow the Company to generate incremental

margin that can offset other increases in costs of providing utility services. The Company also has a focus on cost containment activities that are not captured by the O&M expense PEP goal, such as property and sales tax reductions. These efforts allow the Company to delay requests for retail rate adjustments and also, in the case of long-term wholesale sales, result in larger allocations of costs to non-jurisdictional operations both of which benefit customers through lower rates.

Q. Which employees are eligible for PEP?

A. All non-union employees are eligible for PEP. Any form of compensation provided to the union work force must be collectively bargained. In September 2015, a union that represents IBEW 1116 members bargained for a pay for performance component of compensation for call center employees. While the collective bargaining agreement is still subject to ratification by the union employees, this is the first instance where TEP's union has agreed to tie employee performance to the achievement of goals that directly benefit customers. Similar to the PEP program for non-union employees, the union's inclusion of this pay for performance compensation element in their total compensation program is evidence of its routine nature.

Q. Please explain the PEP Adjustment.

A. The adjustment produces a pro forma Test Year expense level reflecting the average of the PEP expense for the Test Year and the prior year ended June 30, 2014. Since PEP payments are subject to payroll taxes, a portion of the adjustment reflects the incremental effect of payroll taxes. The PEP adjustment is calculated in the same manner as the payroll expense adjustment.

Q. Is the Incentive Compensation adjustment consistent with the 2013 TEP Rate order?

A. No. The Commission approved an adjustment that reflected only 50% PEP for all employees.

Q. Why is TEP asking for 100% of PEP in this case?

A. As I discussed earlier in my testimony, the PEP performance targets are based on factors that are critical to the success of the Company. These targets put a portion of employee's compensation "at risk" which, in effect, ties employee performance to the achievement of goals that directly benefit customers. Whether the goals are financial or service driven, the customer ultimately benefits from the improved performance associated with the cost of the program. Additionally, features of the PEP program ensure that payouts are made only when benefits are produced.

The Company ensures that compensation costs are reasonable by targeting total compensation inclusive of PEP at the median of market. An alternative would be to include this "at risk" portion of compensation in base salary, however, that would not achieve the benefits of linking a portion of cash compensation to specific outcomes that benefit customers. Finally, as I discussed earlier, TEP's compensation structure is less costly than if cash compensation were comprised only of base salary which would be increased in order to meet the compensation programs other objectives related to attracting and retaining talent while targeting median of market compensation levels.

Q. Has the Commission allowed 100% recovery of Short-Term Incentive Compensation before?

A. Yes. In Decision No. 69663 (issued June 28, 2007), page 37, the Commission adopted Staff's position to allow recovery of 100% of Arizona Public Service Company ("APS")

Cash-Based Incentive Compensation Program expense because the "at risk" pay program ties employee performance to the customer's benefit. APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture (APS Exhibit No. 51, Gordon Rebuttal, p. 8). Staff did not oppose inclusion of the Test Year variable incentive compensation expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the Test Year level of expense is tied primarily to performance measures that directly benefit APS customers (Staff Exhibit No. 43, Dittmer Direct, p. 110).

More recently, in Decision No. 75268 (issued September 8, 2015), the Commission adopted the Administrative Law Judge's Recommended Opinion and Order in the EPCOR Water Arizona, Inc.'s ("EPCOR") rate case to allow recovery in rates of incentive compensation so long as total compensation costs were reasonable. In that case, EPCOR removed a portion of the incentive compensation attributable to financial performance based on Commission treatment in its prior rate case. For the reasons explained above, I believe the financial portions of TEP's PEP provide direct benefits to customers through lower rates and should be included in Test Year expenses.

Q. How does TEP ensure that total compensation levels, including PEP, are reasonable?

A. The company targets total compensation, including PEP, at the median of market. This helps TEP remain competitive in attracting and retaining highly skilled employees at a reasonable cost.

Q. Is there an alternative to TEP using PEP while continuing to remain competitive in attracting and retaining a talented workforce?

A. Yes. TEP could raise base salaries and not have an "at risk" pay compensation component. However, this approach would omit the pay-for-performance feature of the compensation program that benefits customers.

Q. Can you provide an example?

A. Yes. Assume we determine that the median total compensation for an employee is $60,000. We can choose to pay that employee $60,000 in base salary or we could choose to pay that employee $55,000 in base salary and offer a target incentive compensation payment of $5,000 tied to the achievement of certain measurable goals related to safety, customer service, reliability, the reduction of costs and TEP's financial soundness. To the extent the performance goals are achieved and the employee is awarded a $5,000 incentive payment, the total amount paid to the employee would be the same $60,000 necessary for TEP to remain competitive in market for talent.

F. <u>Long-Term Incentive Compensation.</u>

Q. Please explain the Company's Long-Term Incentive Compensation program.

A. The Long-Term Incentive Compensation ("LTI") program is comprised of Performance Units ("PU") and Restricted Stock Units ("RSU"). The program is designed to: (1) place

a focus on long-term performance, linking a portion of the compensation of executive officers to the achievement of multi-year financial results, and (2) serve as a retention tool for executive talent. These objectives are achieved by a three-year vesting schedule inherent in each annual LTI award. The PUs will result in cash compensation to the extent that the three-year cumulative financial target is achieved. RSUs also pay out in cash and vest over three years to serve as a retention tool.

Q. How is the LTI portion of total compensation determined?

A. LTI is reflected as a percentage of base salary depending on an executive's position in the Company and their ability to influence financial outcomes.

Q. How does LTI benefit customers?

A. First, LTI allows the Company to attract and retain the executive talent needed to manage a business of the Company's size and complexity. Second, LTI ensures a focus on the long-term performance of the Company which reduces its financing and operating costs that are ultimately reflected in electric rates.

Q. Please explain the LTI Adjustment.

A. The adjustment produces a pro forma Test Year expense level reflecting the average of the LTI expense for the Test Year and the prior year ended June 30, 2014. Since LTI payments are subject to payroll taxes, a portion of the adjustment reflects the incremental effect of payroll taxes.

Q. Does the combination of PEP and LTI result in labor costs that exceed the market?

A. No. The total compensation approximates the median of the market, based on the most recent benchmark studies. The benchmarking information demonstrates that the amounts are reasonable.

Q. Is the LTI adjustment consistent with the 2013 TEP Rate order?

A. No. TEP did not request recovery of this cost in its last rate case, but reserved the right to request it in this case.

G. San Juan Unit 2 Operating Costs.

Q. Please describe the San Juan Unit 2 adjustment to Test Year operating costs.

A. This adjustment is needed to include in Test Year expenses one-third of the 2017 San Juan Unit 2 operating costs as addressed earlier in my testimony.

H. Sundt and San Juan Materials and Supplies.

Q. What is the purpose of the Sundt and San Juan Materials and Supplies adjustment?

A. This adjustment is necessary to reflect in Test Year expenses a three-year amortization of materials and supplies inventory related to the Sundt coal handling facilities and San Juan Unit 2, as addressed earlier in my testimony.

I. San Juan Unit 1 SNCR Operating Costs.

Q. Please explain the San Juan Unit 1 SNCR Operating Costs adjustment.

A. TEP has a 50% interest in San Juan Unit 1 which is operated by Public Service New Mexico ("PNM"). The same environmental compliance matters that are causing the early retirement of San Juan Unit 2 also dictate the environmental controls needed for San Juan Unit 1 to continue to operate. PNM is currently in the process of installing Selective Non-Catalytic Reduction ("SNCR") technology at Unit 1. In accordance with an U.S. Environmental Protection Agency ("EPA") ruling, the SNCR is required to be operational in 2016, prior to the effectiveness of new rates in this rate case. TEP witness

Dukes addresses the post Test Year rate base adjustment associated with these investments. This adjustment reflects the additional operation and maintenance expense that will also be incurred. Additional information about the environmental regulations and their impact on San Juan can be found later in my testimony in the section titled Accounting for Generation Plant Early Retirements.

J. <u>Depreciation and Amortization Expense Annualization.</u>

Q. Please explain your proposed Depreciation and Amortization Expense Annualization Adjustment.

A. TEP witness Dr. Ronald White performed a 2015 Depreciation Study using data provided by the Company from its FERC Form 1. Using Dr. White's study, the Company updated the depreciation rates from the rates authorized in the 2013 TEP Rate Order.

Q. Why is this adjustment necessary?

A. The amount of depreciation expense recorded by TEP during the Test Year reflects less than a full year of depreciation for assets placed in service during the period and that are included in rate base. Moreover, it includes depreciation recorded on assets retired during the Test Year, and thus, not included in rate base. This adjustment produces an annual depreciation expense consistent with the level of depreciable plant in rate base, based on known and measurable changes.

Q. How was the adjustment computed?

A. The adjustment was calculated by first computing the pro forma annualized depreciation expense and then deducting Test Year recorded depreciation expense. For generation assets pro forma annual depreciation was computed by multiplying the end-of-Test Year plant balance in rate base at each generating location and related depreciable FERC plant

account, by the respective current or proposed depreciation rate. For other accounts, annual depreciation was computed using the end-of-Test Year balance in the respective accounts multiplied by the approved current depreciation or amortization rate. For certain assets, a portion of depreciation is capitalized as part of the cost of constructing new assets; thus, such amounts were excluded from the calculation.

K. <u>Property Tax Expense.</u>

Q. Please explain the Property Tax adjustment.

A. The Property Tax adjustment is a pro forma adjustment to Test Year operating expense to reflect the final, adjusted plant in service at the end of the Test Year, using the 2017 statutory assessment ratios, and average property tax rates in effect for the 2015 property tax year. To the extent more current tax rate information becomes available during this rate case proceeding, the Company will update the property tax adjustment.

L. <u>Income Tax Expense.</u>

Q. Please explain the Income Tax Expense adjustment.

A. The Income Tax Expense adjustment is a pro forma adjustment to Test Year operating expenses to reflect income taxes based on final adjusted operating revenues, operating expenses, and rate base. It is computed in two parts. The first part is pro forma current income tax expense, with the tax liability computed as though an actual income tax return was being prepared on final adjusted Test Year taxable operating income. For this purpose, it was necessary to identify all operating book-tax differences ("Schedule M items"), both timing and permanent, and then re-compute current tax expense based on adjusted Test Year operating revenues and expenses as necessary. The tax deduction for

interest was computed using a synchronization methodology reflecting final adjusted rate base and the weighted cost of debt in the capital structure.

The second part of the income tax adjustment is deferred income tax expense. Deferred income taxes are computed on the Schedule M items representing timing differences for which TEP has obtained normalization ratemaking authority from the Commission as previously described in my direct testimony.

Q. What is the adjustment to Deferred Income Tax Expense as a result of the basis adjustment associated with the IRC §48 Energy Credit?

A. As previously discussed in my direct testimony, the election to take the §48 Energy Credit on qualifying property requires a reduction in the basis of the qualifying property for purposes of calculating tax depreciation. The result of this basis reduction is that future tax depreciation deductions will be reduced by an amount equal to one-half of the §48 Energy Credit, or 15% of the basis of the qualifying property.

This basis reduction effectively reduces the value of the §48 Energy Credit from 30% of the cost of the asset (the amount of the unamortized rate-base reduction) to 24.75% (assuming a 35% tax rate applied to the 15% basis reduction). This loss of benefit is reflected as an increase to deferred income tax expense each year as the basis difference reverses through the book depreciation timing difference.

Q. What is the adjustment to Deferred Income Tax Expense for Excess Deferred State Income Taxes?

A. As previously discussed, TEP reduces state deferred income tax expense (and the revenue requirement) for the excess deferred state income taxes associated with utility operations

as the underlying timing differences reverse. Income tax expense has been reduced by the estimated 2015 amortization.

M. <u>Fortis Merger Operating Income Adjustment.</u>

Q. Please explain the Fortis Merger Costs Adjustment.

A. This adjustment removes all merger related costs from the Test Year income statement.

VII. COMPLIANCE WITH FORTIS MERGER CONDITIONS.

Q. Please describe the Fortis merger conditions.

A. The Fortis/UNS Energy merger settlement agreement, which was approved by Decision No. 74689 (August 12, 2014), contains various conditions. The ACC order requires the Company to submit an annual compliance filing addressing the conditions with the first such annual report due April 1, 2016. That said, there are several conditions that need to be addressed in this rate case. I will address most of those conditions, while TEP witness Susan Gray will addresses Conditions 28 and 29 regarding best efforts to maintain or improve quality of service

Q. In Condition 5 of the settlement agreement, Fortis, UNS Energy and the Regulated Utilities (including TEP) agreed that they will not seek recovery of or on any acquisition premium or goodwill amount in any future rate proceeding. Can you confirm that TEP is not seeking such recovery?

A. Yes, TEP is not seeking such recovery.

Q. In Condition 6, the Companies agreed that Fortis shall not allocate any Fortis specific costs to the Regulated Utilities (including TEP) for possible recovery in a future rate proceeding for five years after closing. Can you confirm that TEP is not seeking such recovery in this rate case?

A. Yes, our revenue requirement does not include any Fortis specific costs.

Q. In Condition 7, Fortis, UNS Energy and the Regulated Utilities agreed that they will not pass any costs of the shareholder litigation related to the merger to ratepayers. Does the revenue requirement include any shareholder litigation costs?

A. No, it does not.

Q. In Condition 8, Fortis, UNS Energy and the Regulated Utilities agreed that they would not seek recovery of or on the transaction and transition costs associated with the merger. Does the revenue requirement include any such costs?

A. No, it does not.

Q. Condition 8 also precludes recovery of any Change of Control and Retention payments related to the merger. Can you confirm that TEP is not seeking any recovery of those payments?

A. Yes, the Company is not seeking any such recovery and its customers will not bear the cost of any of such payments.

Q. Condition 9 provides that Fortis shall hold the TEP's ratepayers harmless from the impacts of any fluctuations in foreign exchange rates and any incremental taxes arising from its international ownership structure. Does the revenue requirement include any such impacts?

A. No, the revenue requirement does not include impacts of any fluctuations in foreign

exchange rates or any incremental taxes arising from its international ownership structure.

Q. With respect to Condition 10, has Fortis made an acquisition since the approval of the Fortis/UNS Energy merger that has had any material adverse impact on TEP?

A. No, it has not.

Q. With respect to Condition 11, can you confirm that the revenue requirement in this case does not include any increase in the total compensation of the Senior Management Personnel?

A. The revenue requirement does not include any such increase. As of the end of the Test Year there were 10 executive officers of UNS Energy. This is one less than the number of executive officers as of August 12, 2014, the date of Decision No. 74689 approving the merger. Therefore, pursuant to Condition 11, the portion of the compensation for those Senior Management Personnel that is allocable to TEP has not increased.

Q. With respect to Condition 12, has Fortis completed any merger or acquisition within the United States since the approval of the Fortis/UNS Energy merger?

A. No, it has not.

Q. In Condition 13, Fortis, UNS Energy and the Regulated Utilities agreed that the goodwill and transaction costs of the Fortis/UNS Energy transaction would be excluded from the rate base, expenses and capitalization in the determination of rates and earned returns of TEP. Can you confirm that the rate base, expenses and capitalization excludes the goodwill and transaction costs of the merger?

A. Yes, the revenue requirement does not include those items.

Q. Pursuant to Condition 15, have UNS Energy and the Regulated Utilities prepared a final schedule of the external costs to achieve the merger?

A. Yes, they have. I can confirm that the revenue requirement sought in this docket does not reflect any recovery or recognition of any legal or financial advisory fees, or other external costs associated with the acquisition.

Q. As contemplated in Condition 17, is the proposed capital structure in this docket separate from that of Fortis?

A. Yes, it is. As set forth in TEP witness Kentton Grant's testimony, we are proposing to use TEP's actual capital structure in this rate case.

Q. Under Condition 62, TEP is required to disclose in its rate case filing "each service function (i.e., accounting, treasury, human resources, information technology, risk management, etc.) that it does not fully staff, or which it relies in whole or in part upon Fortis and/or UNS Energy." Please set forth those service functions for which TEP relies on Fortis and/or UNS Energy.

A. Following the closing of the Fortis merger, there are two services for which TEP relies in whole or in part on Fortis. First, while TEP continues to raise debt capital funds through its in-house treasury function, equity capital financing is performed entirely by Fortis. The costs incurred by Fortis for this function are allocated to UNS Energy and TEP and those costs incurred during the Test Year have been removed. Second, TEP coordinates with Fortis on procuring the majority of its insurance coverage to take advantage of scale discounts that would otherwise be unavailable to TEP. TEP contracts with the insurance broker directly and is direct charged for such coverage.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

FPM-1

Tucson Electric Power Company
Bonus Depreciation Ratepayer Benefit Example

Assumptions

Investment	1,000,000
Federal Tax Rate	35.0%
Return on Rate Base	7.34%

Year	Book Depreciation	Regular MACRS Tax Rates	Regular Tax Depreciation	ADIT Reduction to Rate Base	Ratepayer Benefit	100% Bonus Tax Depreciation	ADIT Reduction to Rate Base	Ratepayer Benefit
1	25,000	0.0375	37,500	(4,375)	(321)	1,000,000	(341,250)	(25,048)
2	25,000	0.07219	72,190	(20,892)	(1,533)	-	(332,500)	(24,406)
3	25,000	0.06677	66,770	(35,511)	(2,607)	-	(323,750)	(23,763)
4	25,000	0.06177	61,770	(48,381)	(3,551)	-	(315,000)	(23,121)
5	25,000	0.05713	57,130	(59,626)	(4,377)	-	(306,250)	(22,479)
6	25,000	0.05285	52,850	(69,374)	(5,092)	-	(297,500)	(21,837)
7	25,000	0.04888	48,880	(77,732)	(5,705)	-	(288,750)	(21,194)
8	25,000	0.04522	45,220	(84,809)	(6,225)	-	(280,000)	(20,552)
9	25,000	0.04462	44,620	(91,676)	(6,729)	-	(271,250)	(19,910)
10	25,000	0.04461	44,610	(98,539)	(7,233)	-	(262,500)	(19,268)
11	25,000	0.04462	44,620	(105,406)	(7,737)	-	(253,750)	(18,625)
12	25,000	0.04461	44,610	(112,270)	(8,241)	-	(245,000)	(17,983)
13	25,000	0.04462	44,620	(119,137)	(8,745)	-	(236,250)	(17,341)
14	25,000	0.04461	44,610	(126,000)	(9,248)	-	(227,500)	(16,699)
15	25,000	0.04462	44,620	(132,867)	(9,752)	-	(218,750)	(16,056)
16	25,000	0.04461	44,610	(139,731)	(10,256)	-	(210,000)	(15,414)
17	25,000	0.04462	44,620	(146,598)	(10,760)	-	(201,250)	(14,772)
18	25,000	0.04461	44,610	(153,461)	(11,264)	-	(192,500)	(14,130)
19	25,000	0.04462	44,620	(160,328)	(11,768)	-	(183,750)	(13,487)
20	25,000	0.04461	44,610	(167,192)	(12,272)	-	(175,000)	(12,845)
21	25,000	0.02231	22,310	(166,250)	(12,203)	-	(166,250)	(12,203)
22	25,000		-	(157,500)	(11,561)	-	(157,500)	(11,561)
23	25,000		-	(148,750)	(10,918)	-	(148,750)	(10,918)
24	25,000		-	(140,000)	(10,276)	-	(140,000)	(10,276)
25	25,000		-	(131,250)	(9,634)	-	(131,250)	(9,634)
26	25,000		-	(122,500)	(8,992)	-	(122,500)	(8,992)
27	25,000		-	(113,750)	(8,349)	-	(113,750)	(8,349)
28	25,000		-	(105,000)	(7,707)	-	(105,000)	(7,707)
29	25,000		-	(96,250)	(7,065)	-	(96,250)	(7,065)
30	25,000		-	(87,500)	(6,423)	-	(87,500)	(6,423)
31	25,000		-	(78,750)	(5,780)	-	(78,750)	(5,780)
32	25,000		-	(70,000)	(5,138)	-	(70,000)	(5,138)
33	25,000		-	(61,250)	(4,496)	-	(61,250)	(4,496)
34	25,000		-	(52,500)	(3,854)	-	(52,500)	(3,854)
35	25,000		-	(43,750)	(3,211)	-	(43,750)	(3,211)
36	25,000		-	(35,000)	(2,569)	-	(35,000)	(2,569)
37	25,000		-	(26,250)	(1,927)	-	(26,250)	(1,927)
38	25,000		-	(17,500)	(1,285)	-	(17,500)	(1,285)
39	25,000		-	(8,750)	(642)	-	(8,750)	(642)
40	25,000		-	-	-	-	-	-
	1,000,000	1	1,000,000		(265,444)	1,000,000		(500,955)

Increase in Ratepayer Benefits By Claiming Bonus Depreciation (235,511)

EXHIBIT

FPM-2

Tucson Electric Power Company

220 West Sixth Street
P. O. Box 711
Tucson, Arizona 85702

Kenneth L. Saul
Vice President
and Controller

(602) 884-3630

July 20, 1983

Mr. Neill Dimmick
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Dear Mr. Dimmick:

The Economic Recovery Tax Act of 1981 included a number of changes in the law which directly affected the treatment of depreciation and investment tax credit by investor-owned utility companies. These included the replacement of the Class Life ADR System of depreciation with the Accelerated Cost Recovery System (ACRS), the elimination of the repair allowance on ACRS additions, the revised treatment of the dispositions of ACRS property, the required normalization of depreciation on ACRS property, and the changes in the investment tax credit rates and recapture provisions. In addition, the Tax Equity and Fiscal Responsibility Act of 1982 was responsible for further changes. These included the reduction of future depreciation rates under ACRS, the decrease in the depreciation benefits for facilities financed by industrial development bonds, the required capitalization of construction period interest and taxes, further changes in the investment tax credit rates and recapture provisions, the allowance of a deduction for unused investment tax credit, and the change in the investment tax credit limitation.

As the above changes in the law were enacted, Tucson Electric Power Company analyzed the changes to determine whether further action was required by the Arizona Corporation Commission to insure compliance with the law. In this connection the Company plans to amortize investment tax credits over 15 years the new tax life of public utility property, because we believe that the investment tax credit tax benefits should be spread over the tax life of the equipment generating the credit and that such amortization is consistent with current tax law and the Uniform Systems of Accounts and as such requires no further regulatory approval.

Should you have any questions please do not hesitate to call, and in that regard if we have not heard from you within ten days, we will assume that the procedure outlined is acceptable to you.

Thank you for your consideration in this matter.

Very truly yours,

KLS/nj

DIANE S. McCARTHY
CHAIRMAN

BUD TIMS
COMMISSIONER

RICHARD KIMBALL
COMMISSIONER

LORRIE DROSNY
EXECUTIVE SECRETARY

ARIZONA CORPORATION COMMISSION

July 21, 1983

Mr. Kenneth L. Saul
Vice President and Controller
Tucson Electric Power Company
P. O. Box 711
Tucson, Arizona 85702

Dear Mr. Saul:

We have received your letter of July 20, 1983 regarding the amortization of investment tax credits and find that the procedure you outlined is consistent with our understanding of the law and the Uniform System of Accounts. Therefore, we have no objection to your company implementing same.

Thank you for advising us of your changes.

Very truly yours,

Neill T. Dimmick
Director of Utilities

NTD/nd

Direct Testimony of Dallas J. Dukes

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01933A-15-_____

Direct Testimony of

Dallas J. Dukes

on Behalf of

Tucson Electric Power Company

November 5, 2015

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Exhibits

Exhibit DJD-1 Summary of Utilities with Three-Part Rate Designs

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am the Senior Director of Pricing and Economic Forecasting for Tucson Electric Power Company ("TEP" or the "Company"). I am responsible for monitoring and determining revenue requirements, customer pricing and rates structures for all the regulated subsidiaries of UNS Energy Corporation ("UNS Energy").

Q. Please describe your background and work experience.

A. I hold a Bachelor's of Science degree with a concentration in Accounting from Indiana University and a Master's in Business Administration from Anderson University. I am also a Certified Public Accountant. I have 25 years of experience within the utility industry. Before assuming my current position, I was employed as the Director of Accounting for TEP.

Prior to working for TEP, I was employed by Citizens Gas & Coke Utility ("Citizens Gas"), for approximately five years. Citizens Gas serves approximately 265,000 customers in the Indianapolis, Indiana area. The majority of my time at Citizens Gas was spent as the Controller.

Before then, I was the Controller and Director of Regulatory Affairs for Fountaintown Natural Gas Company, and Southeastern Indiana Natural Gas Company. Prior to that, I was employed by the Indiana Office of Utility Consumer Counselor ("OUCC") for

approximately seven years. The majority of my time at the OUCC was spent as a Principal Accountant. My primary duties at the OUCC were to perform professional investigative audits and to represent the public's interest as an expert witness in proceedings before the Indiana Utility Regulatory Commission.

Q. Could you please summarize your testimony regarding Rate Design?

A. In the first half of my testimony ("Rate Design") I discuss a portion of the Company's proposals to change both residential and small commercial customer classes' rate structures. These changes include: (1) raising the basic service charges for residential and small general service customers; (2) eliminating two of the volumetric rate tiers from the standard residential customer rate; (3) creating a new net-metering rider that allows customers with distributed generation ("DG customer") to offset energy consumption with energy production at the retail rate and to sell excess energy production to TEP and receive bill credits at the Renewable Credit Rate; (4) requiring partial requirements customers (including new net-metering DG customers) to choose from one of the two proposed three-part rate tariffs applicable for their service requirement. TEP is making these proposals to better align rate design with cost-causation and to reduce inter-class inequities. While the Company understands that there are several foundational rate-design principles, the primary principle remains that rates should reflect cost-based recovery. With that in mind, the Company's proposals address the many changes to the utility industry in recent years – including energy efficiency, distributed generation, slowing economic growth and demand response technology – that have contributed to flat or declining energy sales.

Right now, TEP's current rate design for residential and small commercial customers does not reflect the way costs are incurred to serve the customers within these classes. The two-part rate structure of a basic service charge and energy charges is antiquated and does not reflect the modern and burgeoning market for new distributed energy and demand-

management options. The energy (kWh) consumption from seasonal customers and DG customers (for example) is not reflective of the fixed costs imposed on the utility. Put simply, TEP's ability to recover these fixed costs and earn a fair return is limited.

Consequently, the fixed costs inadequately recovered from customers benefiting from the system, but not paying their fair share are shifted to other customers under the present rate design. In particular, higher energy use customers pay a higher percentage share of fixed costs despite the fact that the fixed costs to serve similar lower-use customers is the same. This phenomenon has created the mistaken belief that a customer using less energy reduces the utility's fixed cost to serve that customer – instead of simply a lower utilization of fixed assets that must remain ready to serve that customer.

I further detail how TEP is proposing a three-part rate design that adds a demand charge to the basic service charge and the energy charge. Specifically, the demand charges would recover fixed costs allocated to the customer's class based on the amount of the system they use and when they use it. This rate structure would more accurately reflect the cost of providing service while maintaining consistency with the Company's rate design objectives. I list the precedent for three-part rate designs to residential customers. I also explain that such a design (all of its three components) will provide proper price signals so that customers can make better informed choices about energy usage. In my testimony, I detail the specifics of the Company's proposed three-part rate proposals for Residential Demand and Demand TOU and Small General Service Demand and Demand TOU customers. I also provide the rate impacts to typical residential customers using several average energy (kWh) usages. Ultimately, I explain how the three-part rate rewards customers who improve their load factor consistent with more efficient use of the electric utility system – and how it is not the case that residential customers with very low usage will necessarily benefit less from such a structure.

The Company is not proposing to move all residential and small-commercial customers to a three-part rate structure in this case; however, the Company believes that a transition to a three part rate design is necessary to provide fair and accurate price signals that will lead to expanded technological advancement and more efficient use of the system. TEP is presently requesting to make such a change only mandatory for partial requirements customers, whose measured energy usage, as part of a two-part rate design, doesn't provide for recovery of the fixed cost to serve them and a reasonable opportunity to earn a return on its investment. This is consistent with the treatment of partial requirement customers in all other rate classes. However, TEP is fully supportive, if the Commission were to find it in the public interest, to order a more rapid transition to three-part rate design for all customers.

With regards to the two-part rate structure, TEP proposes to increase the basic service charge to a level closer to the appropriate minimum system-cost level. The Company also seeks to remove two of the rate tiers from the standard residential rate. Specifically, TEP seeks to increase the Basic Service Charge to $20.00 per month for tariff R-01, Residential Service – while having only two tiers in the volumetric Delivery Services-Energy charges (0-500 kWh and usage over 500 kWh). These proposals will begin the transition toward a more balanced rate structure that addresses the issues I have highlighted above.

The Company's proposal for the adoption of a new net-metering rider in this proceeding will only apply to net metering DG customers that submitted a completed application for interconnection to TEP's grid facilities after June 1, 2015. As proposed, existing net-metering DG customers and those with interconnection applications submitted before June 1, 2015 (and ultimately approved) will stay on the current rider until it expires in 20 years. New net metering DG customers will be compensated for any excess energy with a bill credit at the Renewable Credit Rate. Further, the Company will purchase this excess

energy from the DG customer during the billing cycle (that is, eliminating the banking option). This is a further step to send more accurate price signals to net metered customers about their true energy costs. Still, DG customers will see a significant savings on their electric bill, as I show through an example I detail later in my testimony. The new net-metering rider reduces, but does not eliminate, the subsidy provided to applicable DG customers.

I also explain that, since DG customers with net metering are partial requirements customers, the current two-part rate design options are ill-equipped in accounting for how these customers use TEP's system and for fair recovery of fixed cost. This is because two-part rates are designed to recover costs based on average consumption levels for full-requirements customers. So, it is appropriate to require all partial requirement customers, such as net-metered DG customers, to be on a three-part rate schedule. While further mitigating the cost shift I describe in preceding paragraphs, I show how DG customers still save on their total electric bill. These customers can also reduce bills through decreasing billing demand or energy usage.

Q. Please summarize the proposed Economic Development Rider.

A. I discuss the Company's proposal for an Economic Development Rider ("EDR"). This rider will help put TEP's service territory in a better competitive position to attract and expand commercial activity. The EDR will be available to customers with projected peak demand of 3,000 kW or more and a load factor of 75% or higher and for five years from the effective date – providing discounts on monthly electric bills according to a declining schedule. Potential participants must meet several criteria to qualify and the discounts will only apply to the qualifying additional loads from new business or existing business expansion – with total program participation limited to 200 MW. I detail the criteria and further describe the discounts to qualifying customers in the last section of my testimony.

Q. Please provide a summary of your testimony regarding Revenue Requirement.

A. In the second half of my testimony ("Revenue Requirement") I am sponsoring the historical information for the twelve month period ending June 30, 2015, (the "Test Year"), presented on the following schedules:

- A-1, A-2 and A-5
- B-1 through B-5
- C-1 and C-2

I will also be supporting in my direct testimony the pro forma adjustments made to the Test-Year on Schedules B-2 and C-2. Specifically, I will be sponsoring the rate base pro forma adjustments on Schedule B-2 listed below:

- Springerville Unit 1 Leasehold Improvements
- Springerville Unit 1 Lease Equity
- Asset Retirement Obligation
- Post Test Year Plant
- Post Test Year Plant - Renewables
- Delayed Unitization
- Working Capital

Additionally, I will be sponsoring Schedules C-1, C-2 and C-3, and the pro forma accounting adjustments reflected on Schedules C listed below:

- Lost Fixed Cost Revenue
- Environmental Cost Adjustor
- Renewable Energy Standard & Tariff ("REST") and Demand-Side Management ("DSM")
- Non-Retail & Non Recurring Revenue
- Springerville Units 3 & 4

- Sales of SO2 Allowances
- Sales for Resale
- Power Supply Management
- Base Cost of Fuel & Purchased Power
- Springerville Unit 1
- Overhaul & Outage Normalization
- Rate Case Expense
- Injuries & Damages
- Membership Dues
- Bad Debt Expense
- Asset Retirement Obligation
- Springerville Common Facilities Lease
- TEP Headquarters - Retail Space
- Credit Card Processing Fees

II. RATE DESIGN.

A. Overview.

Q. Is TEP proposing changes to its residential, commercial, and industrial rates?

A. Yes. I will be discussing some of the significant rate changes that TEP is proposing for the residential and small commercial customer classes. TEP witness Craig Jones will be discussing other proposed rate design changes.

Q. What are the rate design changes TEP is proposing?

A. To better align rate design with cost-causation and to reduce inter-class inequities, TEP is proposing the following changes for the residential and small commercial (small general

service) rate classes:

- Increase the basic service charge to $20 for standard residential customer rates.
- Increase the basic service charge to $30 for small general service customer rates.
- Eliminate two of the volumetric rate tiers from standard residential customer rates.
- Offer two three-part rate structure options to all customers meeting the applicability requirements for the residential and small general service rate classes.
- Freeze and grandfather the current Rider R-4 (Net Metering for Certain Partial Requirements Service (NM-PRS)), Pre June 1, 2015. Rider R-4 will have a proposed expiration date of May 31, 2035.
- Create a new Rider R-15 (NM-PRS), Post June 1, 2015, that discontinues the banking of kilowatt-hours ("kWh") but allows a net metered customer to: (i) continue to offset energy consumption with energy production at the retail rate and (ii) sell excess energy production to TEP at the Renewable Credit Rate as described in the testimony of Carmine Tilghman.
- Require partial requirement customers qualifying for the new Rider R-15 to choose from one of the two proposed three-part rate tariffs applicable for their service requirement.

Q. What are the guidelines or criteria adhered to in evaluating the Company's proposed rate design modifications?

A. TEP is generally following the principles outlined over five decades ago by Professor James C. Bonbright in his work, "Principles of Public Utility Rates," which was reissued in its second edition in 1988. While Professor Bonbright's "Principles" go back five decades, they continue to serve as the foundation for reasonable rate design objectives.

Q. What are those foundational principles?

A. They are as follows:

- The related "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
- Freedom from controversies as to proper interpretation.
- Effectiveness in yielding total revenue requirement under the fair-return standard.
- Revenue stability from year to year.
- Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
- Avoidance of "undue discrimination" in rate relationships.
- Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

Q. Is there one principle in rate design that is foundational or primary?

A. Yes. The principle of cost-causation, i.e. rates should reflect cost based recovery. The further away you get from this fundamental foundation, the closer you get to unduly burdensome and discriminatory rate structures that allow for both intra- & inter- class subsidization.

Q. Have fundamental changes occurred in the utility industry since Bonbright's principles were formulated?

A. Yes. At the time Bonbright's principles were formulated the utility industry was typically experiencing steady year-over-year growth in kWh sales and expanding its generation, transmission and distribution systems. In addition, customers had little to no options for alternative power supplies or the ability to control their demand on the expanding utility systems.

However, today there is a growing market of energy efficiency, distributed generation and demand response options available to our customers. New digital metering technology and communication applications also allow today's electrical customers to monitor how and when they use power and the grid.

These factors have contributed to flat or declining kWh sales. Rooftop solar and net metering have become significant factors, especially in Arizona, including TEP's service territory. So the discussion of appropriate pricing and incentive structures has become more complex and necessary as it is a much more important issue.

Q. What do you mean by appropriate pricing structures?

A. To address that, I first need to discuss the cost structure of TEP. The majority of utility costs are fixed – that is, they do not change with electricity usage. In the case of TEP, its fixed costs stem from investment in and maintenance of equipment and infrastructure, and the salaries of employees that are needed to provide safe, reliable power regardless of the kWh consumption of each individual customer.

Like any electric utility, TEP has an obligation to invest in and maintain a system to meet the <u>potential</u> maximum demand of every customer. For that reason, TEP incurs essentially the same costs to serve a residential customer who uses 10 kilowatts ("kW") for 10 hours per month (100 kWh) as it does to serve a neighbor who uses 10 kW for 100 hours per month (1,000 kWh). The only completely avoidable cost is the variable cost related to the energy production, primarily fuel, purchased power and any operating and maintenance ("O&M") costs directly related to energy production or procurement. It would be cost prohibitive and economically unsound to invest in an electrical system scaled differently to meet the unique and constantly changing demands of each individual customer.

Q. Are TEP's residential & small commercial pricing structures presently designed appropriately based on the principal of cost causation?

A. No. The Company's current rate design for residential and small commercial customers does not reflect the way costs are incurred to serve these customers. For decades, rate designs for these classes have incorporated a very simplistic two part rate structure; a basic service charge (customer charge) and energy charges. This was defensible because these customers typically had relatively similar usage levels and patterns. It also allowed utilities to avoid the higher cost of meters capable of measuring demand.

Historically, basic service charges have been limited to bare minimum levels while inclining price rate tiers have been added, forcing customers who use more power to pay an increasingly disproportional share of the fixed costs incurred on behalf of all customers. Today, though, customers have access to a burgeoning market of distributed energy resources ("DER") and demand management opportunities. The growing inequities that result from these new options are exacerbated by utility rates that have become even more inequitable. Thus, TEP is proposing rate design changes that are designed to address those inequities.

As I described above, a customer's individual kWh consumption is not indicative of the fixed costs they impose on their utility. A few examples to illustrate this point are summarized below.

- Seasonal Customers. TEP's service territory has many customers who only live in their homes for part of the year. Under the Company's current rates, these customers only pay a portion of the fixed costs associated with providing safe, reliable service to their homes.

- Vacant homes or businesses. Vacant homes and unoccupied apartments with little to no consumption generate far less revenue for TEP than is needed to cover the fixed costs necessary to assure service when re-inhabited.
- DG Customers. Customers with DG power systems still rely on TEP to supply the full potential kW requirements of their home whenever they need it. These customers also need the local distribution grid to support the reliable operation of their systems and to accept any excess power they generate. While TEP must provide the infrastructure to address these needs, it cannot recover the cost of these services from DG customers under current rates, which rely heavily on energy charges to recover fixed costs. This inequity is exacerbated by net metering, which allows customers to "bank" their systems' excess energy for free and exchange it for on-demand service from their utility.

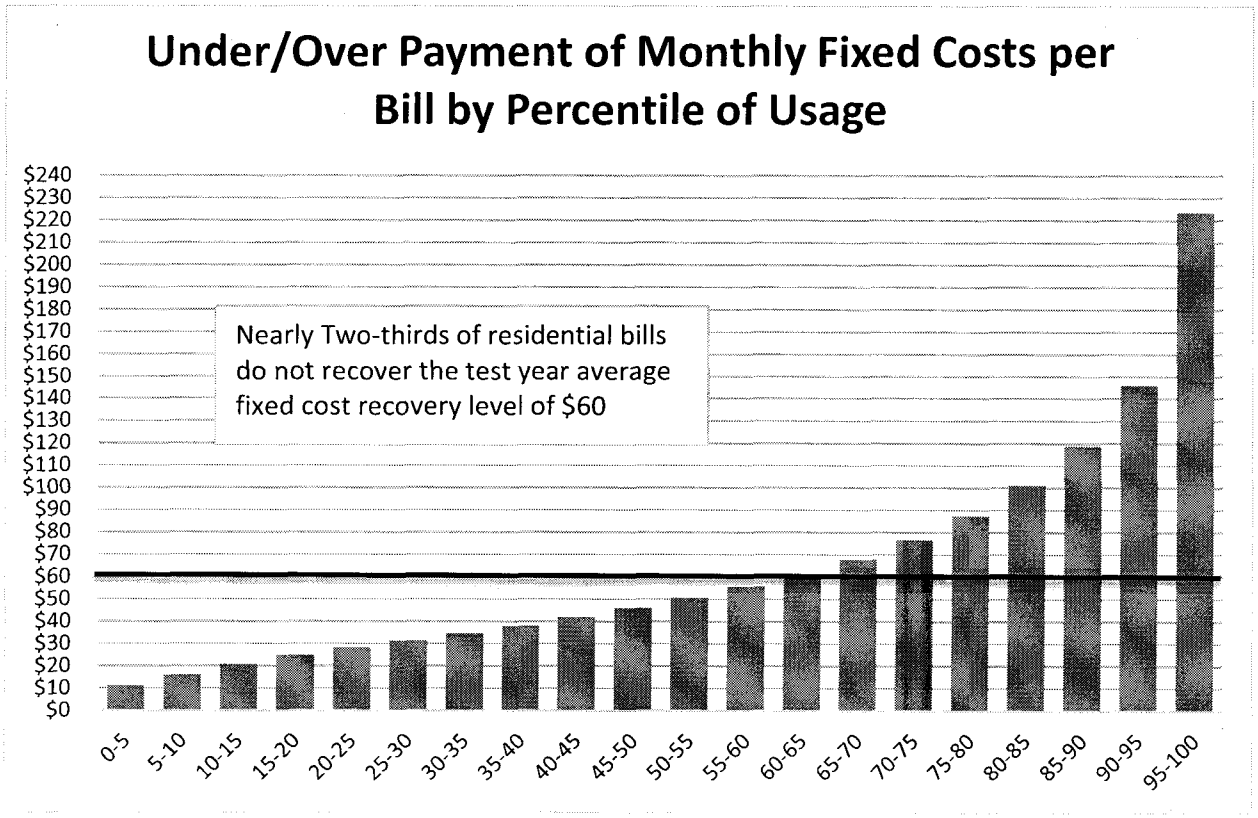
The situations described above limit TEP's ability to recover its fixed service costs. Nearly one out of every three residential (Residential R-01) bills issued by TEP during the test year – 1,308,714 to be precise – reflected usage of 400kWh or less. Because even a studio apartment with basic appliances and moderate usage would likely consume almost 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers. TEP recovered only $10 to $33 in fixed costs per month from these issued bills – a fraction of their equitable share of the fixed costs the Company incurs to provide service on their behalf. Those fixed costs are described in more detail in the testimony of TEP witness Craig Jones.

In rate proceedings, those unrecovered costs are shifted to other customers through the present volumetric rate design. Another way to look at it is: if each of the residential bills referenced above recovered just the test year's average monthly fixed cost recovered for

the class of $60, a minimum of $35 million would have been recovered and not have been shifted to other customers.

Q. Does the inclining block rate structure also contribute to these intra-class inequities?

A. Yes. As discussed above, kWh consumption doesn't directly correlate with how much of the system a customer may require at any point in time. TEP recovered, on average, $60 in fixed costs per bill from residential customers during the test year. As shown in the chart below, though, approximately two-thirds of the bills issued in the last 4 years to residential customers (applying the current R-01 rate) did not provide fixed cost recovery equivalent to the class average established in TEP's last rate case. This means that just over one-third of residential customers' bills recovered above average amounts of fixed costs, while two-thirds recovered below average amounts. There is no cost basis for such a disparity and as such this structure is unduly burdensome and unequitable to the higher consumption users.



particular billing period, their utility's fixed costs are reduced by a comparable amount. But such reductions simply result in lower utilization of utility assets that must remain at the ready to power every light, appliance, fan, air conditioner, computer, television and other equipment their customers might choose to use.

Q. Has TEP experienced a reduction in energy sales and use-per-customer ("UPC") for the residential and small commercial rate classes?

A. Yes, since 2011 TEP has seen a decline of approximately 7.5% in its UPC in just the residential customer class alone.

Q. What do you believe is driving these reductions?

A. There are several factors contributing to lower consumption, including: adoption of energy efficiency measures; more energy efficient construction codes and appliance standards; increased use of distributed generation; challenging economic conditions; and other conservation efforts by TEP's customers.

Q. Have these sales and UPC reductions resulted in lower costs for customers?

A. On the whole, they have not. While individual customers have enjoyed lower bills due to energy efficiency and DG systems, their bill savings have not resulted in equivalent system demand reductions. The level of investment and maintenance required to meet customer demand has not been reduced; rather, the burden of paying for it has been shifted from customers who use less energy to those who use more.

Q. Why is it important to distinguish between system savings and individual savings?

A. TEP witnesses Craig Jones and Carmine Tilghman will provide more detail about the cost drivers associated with the electric distribution system and the relationship with peak demand. Broadly speaking, though, the distribution system is a network designed

primarily to meet the non-coincidental peak demands of customers. The transmission and generation systems, by contrast, are designed to meet the coincidental peaks of the distribution system, with reserves and margins for growth and planning purposes.

When customers reduce their energy consumption through temporary vacancies or intermittent solar DG systems, their peak demand typically does not change. In the case of DG customers, it could even grow as a result of oversized generating facilities being added to maximize energy production; that is further discussed in the testimony of Carmine Tilghman.

So while customers enjoy bill savings from their reduced usage, the Company's fixed system costs for distribution service are not reduced. System savings can be realized in future years through reductions in the system's coincidental peak demand. So customers need to be given the proper price signals and incentives through rates to promote those beneficial changes.

Q. How could residential and small commercial rates be structured to most accurately reflect the costs of providing electric service?

A. The closest rate structure from a cost recovery only basis is a straight fixed-variable ("SFV") design. Under this method, the monthly basic service charge recovers all fixed service costs, while variable charges reflect those costs directly tied to energy usage.

Q. Is TEP proposing SFV rates in this proceeding?

A. No. Adoption of strict SFV rates would result in dramatic rate increases for customers at lower kWh consumption levels and not provide adequate price signals to customers to reduce their impacts on the electrical system. Such a structure is just too blunt an

instrument and would dissuade additional technological advancements and behavioral changes resulting in more efficient use of the utility system. This is not consistent with the Company's rate design objectives of providing more accurate price signals to more fairly recover fixed cost and promote more efficient use of the system and thus reduce cost for all customers.

Q. What type of rate structure would more accurately reflect the cost of providing service and also be consistent with the Company's rate design objectives?

A. A three-part rate design consistent with those presently employed for larger customers would be more appropriate and provide a balance between fixed cost recovery, cost causation and price signals incenting more efficient use of the utility system.

Q. How would costs be recovered through the three-part rate design proposed by the Company in this proceeding?

A. Three-part rates, incorporate the following components:

- **Basic Service Charge** – To recover fixed costs directly attributable to the customer, including the meter, service line, on-site equipment, meter reading and equipment, customer support and billing and a portion of the minimum distribution system cost.
- **Demand Charges** – To recover fixed costs allocated to the customer's class based on the amount of the system they use and when they use it.
- **Energy Charges** – To recover variable costs directly attributable to the customers' energy use.

Q. Do any utilities use three-part rates for residential and small commercial customers?

A. Yes. The Company had a review done by Black & Veatch Corporation and they identified 39 utilities offering three-part rates to residential customers. Please see attached **Exhibit DJD-1** listing the utilities and basic tariff information for 43 different

three-part rate designs presently in effect throughout the United States, including Arizona.

Q. Would TEP support three-part rates for all customers, not just partial requirements customers?

A. Yes. But it is critical that each component of the three-part rate closely reflects the actual cost of service. If properly designed, three-part rates more fairly allocate costs to the customers within a class that "cause" them and provide proper price signals that help customers make informed decisions regarding their energy and electrical system usage. Three-part rates also reward customers for better load factors and reductions in peak usage – attributes that lead to lower system costs, which benefits all customers.

The Basic Service Charge should be designed to recover the average unavoidable fixed costs that utilities incur each month. It should provide customers with a more accurate price signal that reflects the costs incurred to assure minimum service from the electrical grid to provide safe and reliable service.

Similarly, the Demand Charge should provide customers with a price signal that accurately reflects the cost of system resources that must be available to serve their individual peak load. They then can make proper usage and equipment purchase decisions that would reduce that portion of their bill while producing system benefits.

Finally, Energy Charges should reflect costs that are entirely avoidable when energy consumption is reduced.

B. Proposed Changes to the Standard Two-Part Rates.

Q. Is TEP requesting that all residential and small commercial customers be migrated to a three-part rate structure?

A. Although TEP is proposing a three-part rate structure as an option, it is not proposing to require all residential and small commercial customers to migrate to a three-part rate structure in this proceeding. TEP is requesting to begin moving toward a more balanced rate structure that would make such a move possible in its next rate filing.

Q. What are reasonable steps that can be taken in this proceeding to begin this transition?

A. For the standard residential and small general service rates (two-part rate structure classes), we can start by moving the basic service charge closer to the appropriate minimum system cost recovery level. In addition, we can remove two of the rate tiers from the standard residential rate. These changes will provide for more equitable recovery of fixed cost and reduce intra-class subsidization. The Company is proposing these changes at a level that it believes will provide for significant improvement of the rate structures without undue rate shock.

Q. What changes specifically are you requesting for residential customers in this proceeding?

A. For tariff R-01, Residential Service, we are requesting an increase in the Basic Service Charge to $20.00 per month. The Company is also requesting the elimination of the third and fourth tiers in the volumetric Delivery Services-Energy charges. In other words, the R-01 will have one tier from 0 – 500 kWh and another for all usage over 500 kWh.

C. <u>Net Metering Rider Modifications.</u>

Q. Is TEP requesting changes to its net-metering tariffs? What changes are you proposing for customers qualifying for Net Metering?

A. Yes. We are proposing the adoption of Rider R-15, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015. The Company's proposed net metering tariff is described in the testimony of Carmine Tilghman. The applicable three-part standard offer tariffs will be <u>mandatory</u> for partial requirement Net Metering customers taking service under this Rider.

Q. Will Rider R-15 apply to all Net Metering customers?

A. No. Most Net Metering customers will be grandfathered under the existing Net Metering tariff. Rider R-15 will only apply to Net Metering customers that submit completed application for interconnection to TEP's grid facilities after June 1, 2015. All existing Net Metering customers interconnected to TEP's system prior to June 1, 2015 and those with completed interconnection applications that were submitted prior to or on June 1, 2015 (and ultimately approved) will stay on the Net Metering Rider R-4 for a period not to exceed twenty years. TEP is proposing that the Rider R-4 expire no later than May 31, 2035.

Q. How will the Company purchase the excess energy produced by the Net Metering customer's facility?

A. Net Metering customers would be compensated for any excess energy their DG facility produces and delivers to TEP with a credit on their current monthly TEP bill using the Renewable Credit Rate. Net Metering customers could carry over unused bill credits to future months if they exceed the amount of their current bill.

Q. What is the Renewable Credit Rate and how is it developed?

A. The Renewable Credit Rate is the price at which TEP will compensate customers with DG for the excess energy produced by the customer's generation facility as discussed in Carmine Tilghman's testimony.

Q. If adopted, what issues will be remedied by TEP's Net Metering tariff proposal?

A. First, eliminating the banking option for excess energy production will no longer give DG customers the impression that their excess energy can be stored on TEP's system for future use at no cost. By simply purchasing the excess energy from the customer during their billing cycle, as opposed to allowing customers to use the kWh credits at a later time, TEP will send more accurate price signals to Net Metered customers about their true energy costs.

Second, eliminating the banking option helps to partially alleviate the bypass of fixed cost recovery that occurs when customers self-generate a portion of their energy requirements. The bypass of fixed cost recovery by DG customers can be illustrated with an example.

The table below presents the average monthly fixed cost recovery and average pre-tax monthly bills using TEP's proposed rates for three types of residential customers at monthly electric usage levels of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh. The three customer types all take service under standard offer tariff R-01 and the bills in this table are calculated with the R-01 rates proposed in this application. The first case is a full-requirements customer with no DG, the second a DG customer with Net Metering and banking of excess kWh, and the third a DG customer with Net Metering and utility purchase of excess kWh as proposed in this application. The DG customers have solar photovoltaic ("PV") systems sized to produce a kWh output that would yield zero excess

kWh on an annual basis and the load profiles for each customer size are from actual TEP customer data.

Monthly Usage	R-01 Full Requirements Service	R-01 with Net Metering: Banking Excess kWh	R-01 with Net Metering: TEP Purchases Excess kWh
500 kWh per Month			
Monthly Fixed Cost Recovery	$50.74	$20.00	$41.13
Average Monthly Bill (pre-tax)	$74.16	$23.42	$37.70
Unrecovered Fixed Costs	NA	$30.74	$9.61
Monthly Bill Savings	NA	$50.74	$36.46
900 kWh per Month			
Monthly Fixed Cost Recovery	$81.20	$20.16	$51.02
Average Monthly Bill (pre-tax)	$120.86	$23.61	$44.69
Unrecovered Fixed Costs	NA	$61.04	$30.18
Monthly Bill Savings	NA	$97.25	$76.17
1,200 kWh per Month			
Monthly Fixed Cost Recovery	$104.92	$20.00	$60.36
Average Monthly Bill (pre-tax)	$156.54	$23.42	$51.66
Unrecovered Fixed Costs	NA	$84.92	$44.56
Monthly Bill Savings	NA	$133.12	$104.88
1,500 kWh per Month			
Monthly Fixed Cost Recovery	$128.65	$20.11	$62.52
Average Monthly Bill (pre-tax)	$192.10	$23.54	$53.30
Unrecovered Fixed Costs	NA	$108.54	$66.13
Monthly Bill Savings	NA	$168.56	$138.80

In this example, a residential customer on R-01 using 900 kWh per month and no DG system would pay an average of $81.20 per month in fixed costs. The fixed cost recovery in this case consists of the fixed Basic Service Charge and the variable Delivery Services-Energy charges at that level of consumption. By contrast, the same customer with a DG system that produces the same annual kWh as consumed pays an average of $20.16 per month if allowed to bank kWh produced in excess of usage at any time in order to offset consumption at a later time. This results in a fixed cost recovery shortfall of $61.04. With a $20.00 per month Basic Service Charge, this customer is paying only $0.16 per month

above the Basic Service Charge for the fixed costs associated with the generation capacity, transmission, and distribution infrastructure to serve the customer.

The same DG customer under the regime where TEP purchases the excess kWh generated as proposed in this filing pays $51.02 in fixed costs. Under TEP's proposal, the Company would recover $30.86 more of its fixed costs than under the banking scheme, but is still $30.18 short of the fixed costs recovered from the non-DG customer. Keep in mind that the $61.04 in fixed costs that is bypassed using the banking scheme, like the utility infrastructure it is paying for, does not go away. It will ultimately have to be recovered from the other customers on the system who are not Net Metering customers. Because TEP purchases the excess kWh production, there are now $30.86 less in fixed costs that must be recovered from customers without Net Metering.

Q. Customers with DG systems undertake a significant capital investment to reduce their electric bills. How would this proposal impact their savings?

A. Under this proposal, DG customers would still see significant savings on their electric bills. In the example above, the monthly pre-tax bill savings for a Net Metering customer using 900 kWh per month are reduced by $21.08, from $97.25 to $76.17. This $76.17 is still a 63% reduction in that DG customer's monthly electric bill.

Q. Will this change to TEP's treatment of Net Metering completely eliminate the shifting of fixed costs due to DG?

A. No. The adoption of the new net-metering rider, which no longer allows for energy banking, will reduce but not eliminate the subsidy. However, when combined with the proposed standard offer three-part tariff, the magnitude of cost shifts to non-DG customers will be greatly reduced.

Q. Why is TEP proposing that new Net Metering customers be required to take standard offer service on a three-part tariff?

A. As I mentioned earlier, the proposed Net Metering changes will not fully mitigate the DG cost shift. The DG customers' usage patterns and load profiles are no longer those of a full requirements customer and their rate design should be consistent with other partial requirements customers. The three-part rate design is presently approved by the Arizona Corporation Commission ("ACC" or "Commission") for TEP's partial requirement customers in the larger rate classes.

The cost shift is also increased by the fact that a majority of the fixed costs to serve residential and small commercial customers are recovered through variable energy usage charges. These usage-based charges have built-in rate tiers that charge more for usage when a customer's consumption reaches each subsequent threshold. Assuming that fixed costs can fairly and equitably be recovered primarily through volumetric rates ignores the ever <u>increasing</u> magnitude of the cost shift created by DG customers, as well as energy efficiency and conservation.

DG customers avoid paying a substantial portion of their fixed costs of the system by avoiding these higher consumption levels. When the energy produced by a DG system is used by the customer and netted against the energy that would be delivered by the utility, the fixed costs embedded in the variable utility charges go unrecovered. Furthermore, the recovery of these fixed costs is being avoided primarily at the higher tier rates in the inverted block rate structure.

D. Three-Part Rate Proposals.

Q. Please summarize TEP's new three-part rate proposals for residential customers.

A. For the residential class, TEP is proposing RES-D and RES-D-TOU. For RES-D, we are proposing the same $20.00 per month Basic Service Charge that we are proposing for R-01. Also, we are proposing a two-tier monthly Demand Charge with the break point at 7 kW. Billing demand will be based on the 1-hour maximum measured demand during the billing month. The Delivery Service-Energy charges have a single tier and are reduced significantly from those in R-01 to reflect the fixed cost recovery being more properly recovered through the demand charges. All other charges are identical to those in R-01. For RES-D-TOU, the Basic Service, Demand, Delivery Services-Energy, and all other charges except Base Power are the same as those for RES-D. The Base Power Charges vary by time of use.

Q. How would the proposed three-part rates impact residential customer bills?

A. The table below shows average monthly bills (pre-tax) for residential customers using an average of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh. The customers in this example are full-requirements customers taking service under R-01 and RES-D at proposed rates. The following customer examples were developed from TEP's residential customer usage data. It is evident from the comparisons presented in this table that customers at the lower end of the usage spectrum pay higher monthly bills on the three-part rate than on the two-part rate.

Bills calculated using the three-part rate will exceed bills using the two-part rate at lower levels of consumption. As usage increases, customers on the three-part tariff will have lower monthly bills.

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill		
		R-01	RES-D	Difference
500 kWh	18.4%	$74.16	$83.51	$9.35
900 kWh	23.3%	$120.86	$121.33	$0.47
1,200 kWh	26.7%	$156.54	$147.29	($9.25)
1,500 kWh	31.5%	$192.10	$169.45	($22.65)

Q. From this information, can one conclude that residential customers with very low usage will benefit less from a three-part rate than higher usage customers?

A. No. One other piece of information in this table is the average monthly load factor for each customer profile. Load factor is a concept that indicates how a customer is using energy relative to the peak demand that the customer incurs. One commonly used definition of the load factor is the average demand over a period divided by peak demand. By this definition as average demand increases relative to peak demand, the load factor increases. It also follows that as a customer uses more energy, i.e., more kWh, for any given peak demand, the load factor increases. It is generally accepted that a higher load factor implies a more efficient use of the utility system.

The load profiles used for these bill comparisons were developed from test-year TEP residential customer load data. One trend that is evident is that higher usage customers generally have higher load factors. As shown in the table above, the lower usage customers with lower load factors see bill increases on the three-part rate. However, these bill increases are reduced and customers actually realize a positive benefit at higher usage levels and higher load factors. This occurs because the load factor is increasing not peak usage. The higher usage customers are using more kWh per kW than lower usage customers. Because the Delivery Services-Energy charges in the three-part rate are approximately 60% lower than those in the two-part rate, the benefits of the lower per kWh charges begin to take over as the load factor increases.

Q. What can one conclude from these results?

A. The three-part rate with a demand charge rewards customers with higher load factors, all else equal. More important, a three-part rate will reward customers who improve their load factor. If residential customers choose to take service on a three-part rate they will reduce their electric bills by improving their load factor or maintaining a higher load factor. As I mentioned earlier, higher load factors are consistent with more efficient use of the electric utility system. Under a three-part rate, customers receive a price signal encouraging them to improve their load factor, which benefits the customer by reducing their electric bills and benefits all TEP customers as the system is used more efficiently.

Q. Are there other ways customers can benefit from a three-part rate design?

A. Absolutely. Customers continue to have more options to save in the future when technology can help them manage and reduce demand. As a simple example, consider someone with two air conditioning units, a pool pump and an electric water heater. That person (or TEP through energy efficiency programs) could invest in systems that prevent all four appliances from coming on at one time. The units are cycled and thus the impact on the system and their demand charge is reduced as it relates to those pieces of equipment. These types of control systems are currently available and properly designed rate structures and customer education programs could lead to more installations and system benefits, by providing the proper economic incentive.

Q. Could a three-part rate structure for residential and small commercial customers encourage development of business models and customer applications aimed at reducing customers' individual demand?

A. Yes. A three-part rate structure will provide customers pricing options that could lead to earlier adoption of new energy technologies. For example, TEP and other companies will

be incentivized to combine technologies like solar panels, energy storage and demand control systems to maximize customer savings and profitability of their programs.

Q. Please summarize TEP's new three-part rate proposal for small commercial customers.

A. The small commercial three-part rate tariffs TEP is proposing are SGS-D and SGS-D TOU. We are proposing a Basic Service Charge of $30.00 per month and a two-tiered Demand Charge with a break point at 7 kW. The second tier in the GS-10 Delivery Services-Energy charges has been removed for the three-part rate and the energy charges are reduced significantly to reflect the fixed cost recovery being more appropriately recovered through demand charges. For SGS-D TOU the Basic Service, Demand, Delivery Service-Energy, and all other charges except Base Power are the same as those for SGS-D. The Base Power Charges vary by time of use.

Q. Is TEP proposing that all residential and small commercial customers take service on three-part rate tariffs?

A. No. At this time TEP is proposing three-part rate tariffs as optional for residential and small commercial customers who are not taking service under the Net Metering Rider R-15. All residential and commercial Net Metering Rider R-15 customers will be required to take service under the applicable three-part standard offer tariff.

E. <u>Partial Requirements Customers.</u>

Q. In your summary you state that TEP is proposing that partial requirement customers qualifying for the new Net Metering Rider R-15 must choose from one of the two proposed three-part rate tariffs applicable for their service requirement. Why is TEP proposing to require these customers to use a three-part rate tariff?

A. Simply stated, the Company's current two-part rate design options do not account for how these customers use the system and will never properly recover a fair level of fixed costs. **The two-part rates are designed to recover costs based on the average consumption levels of full-requirements customers** - and as presently designed and proposed rely on energy charges to recover fixed cost. Also as discussed above, even with the changes we are proposing to our present full requirement tariffs (higher Basic Service Charges and elimination of two residential tiers) – these new rates will continue to recover the majority of fixed cost through volumetric energy rates.

Q. Do TEP's proposed three-part rates for partial-requirements residential and small commercial customers further mitigate the DG cost shifting covered earlier?

A. Yes. The table below presents monthly fixed cost recovery and average monthly electric bills for the same four residential customer profiles that I presented earlier. The examples in this case are for a full-requirements residential customer on R-01 at proposed rates and two partial-requirements Net Metering customers, one on the proposed R-01 two-part rate and the other on the proposed RES-D three-part rate. In both of the Net Metering cases, TEP is purchasing the excess output of the DG system at the Renewable Credit Rate.

As is evident from the results in this table, the three-part rate goes a long way toward further mitigating the DG cost shift. For the 900 kWh per month customer I discussed earlier, only $10.11 per month in fixed costs is now bypassed. Furthermore, the customer is still saving $55.87 per month on their total electric bill, which is a savings of 46% from R-01 full requirements service.

Monthly Usage	R-01 Full Requirements Service	R-01 2-part Rate with Net Metering	RES-D 3-part Demand Rate with Net Metering
500 kWh per Month			
Monthly Fixed Cost Recovery	$50.74	$41.13	$55.92
Average Monthly Bill (pre-tax)	$74.16	$37.70	$52.65
Unrecovered Fixed Costs	NA	$9.61	-$5.18
Monthly Bill Savings	NA	$36.46	$21.51
900 kWh per Month			
Monthly Fixed Cost Recovery	$81.20	$51.02	$71.09
Average Monthly Bill (pre-tax)	$120.86	$44.69	$64.99
Unrecovered Fixed Costs	NA	$30.18	$10.11
Monthly Bill Savings	NA	$76.17	$55.87
1,200 kWh per Month			
Monthly Fixed Cost Recovery	$104.92	$60.36	$80.40
Average Monthly Bill (pre-tax)	$156.54	$51.66	$71.94
Unrecovered Fixed Costs	NA	$44.56	$24.52
Monthly Bill Savings	NA	$104.88	$84.60
1,500 kWh per Month			
Monthly Fixed Cost Recovery	$128.65	$62.52	$83.91
Average Monthly Bill (pre-tax)	$192.10	$53.30	$74.93
Unrecovered Fixed Costs	NA	$66.13	$44.74
Monthly Bill Savings	NA	$138.80	$117.17

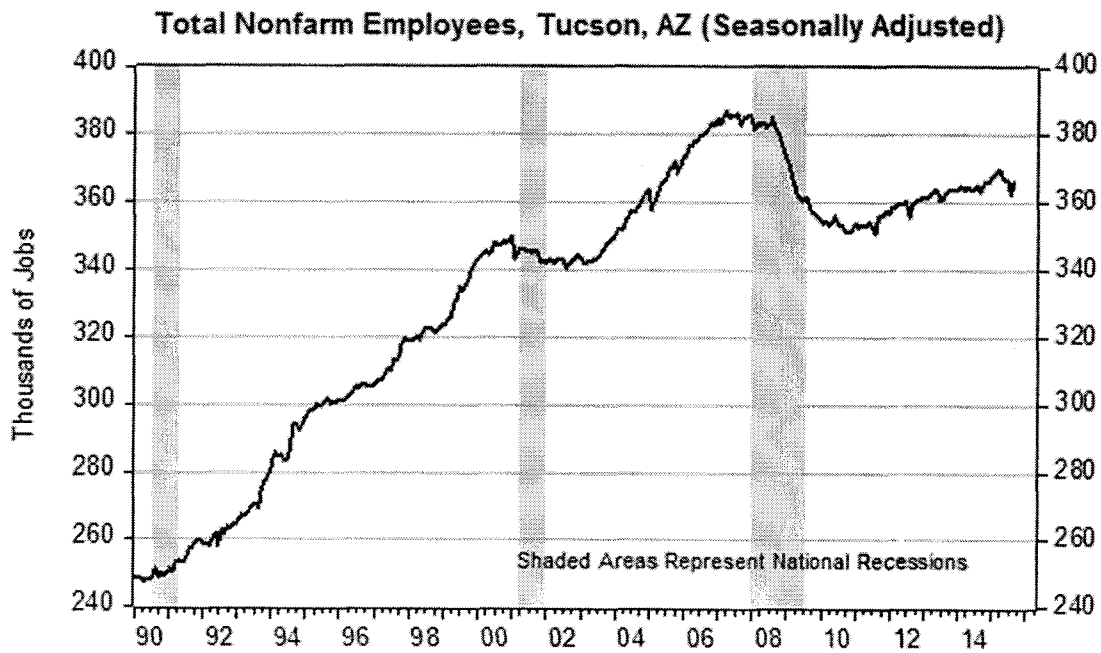
Q. You showed how residential DG customers with Net Metering will continue to see significant bill savings on the proposed three-part tariff. Are there any other opportunities for these customers to lower their monthly bills and realize added savings?

A. Yes. The incentive still exists for DG customers to reduce bills by decreasing billing demand or energy usage. However, because volumetric energy charges embodied in the three-part rate are much lower than those in the two-part rate, the potential savings from reduced energy use are not as high as those from reducing peak demand. Regardless, peak demand reductions that are greater than energy use reductions on a percentage basis will yield a higher load factor and provide benefits to the customer and the electric system.

F. **Economic Development Rider.**

Q. Why is TEP proposing an Economic Development Rider in this proceeding?

A. The TEP service territory has been very slow to recover from the economic downturn post 2007, which has resulted in lower kWh sales and thus fewer sales units to spread the fixed cost of the system and more cost being allocated to the remaining customers. I've already discussed the declining sales in the TEP service territory and those impacts on customers' bills. The Tucson area has also been very slow to recover from an employment perspective as well. As shown in the chart below the Tucson area has yet to get back to employment levels that existed in 2006.



Souce: U.S. Department of Labor

Q. Do you believe an Economic Development Rider could assist business growth in TEP's service territory?

A. Yes. The inclusion of this additional incentive along with the rate design changes discussed in TEP witness Craig Jones' testimony, reducing rates for the business classes, should put the TEP service territory in a better competitive position to attract and expand business load. This would be beneficial to the entire customer base and the State of Arizona.

Q. Please describe TEP's proposed Economic Development Rider.

A. TEP is proposing to offer Rider 13, Economic Development Rider ("EDR") to current or potential commercial and industrial customers that meet certain economic development criteria within the TEP service areas. The EDR will be available to customers with a projected peak demand of 1,000 kW or more and a load factor of 75% or higher. The EDR will be available for five years from the effective date and provides qualifying customers with discounts on monthly electric bills according to a declining schedule over a five-year period at which point the discount is terminated. The discounts will apply only to the qualifying additional loads from new or expanding business operations and total program participation will be limited to 200 MW of applicable load.

Q. What are the qualifying criteria for the proposed EDR?

A. In addition to demand and load factor, customers must meet several criteria to qualify for the proposed EDR. First, potential EDR customers must qualify for at least one of two Arizona state tax credit programs designed to promote business recruitment, retention, and expansion. Arizona's Quality Jobs Tax Credit (A.R.S. § 41-1525) program provides a tax credit for net increases of at least 25 full-time employees residing in the state and hired in qualified employment positions. The Qualified Facility Tax Credit (A.R.S. § 41-1512) program provides for a refundable tax credit for qualifying capital investment in a

manufacturing facility that creates new jobs, of which at least 51 percent pay a wage that equals or exceeds 125 percent of the median state wage. Also, the applicant must provide health insurance coverage for all net new full-time positions and cover at least 80 percent of new employees' health care premiums.

Q. Please describe the discounts available to customers qualifying for the proposed EDR.

A. All provisions, charges, and adjustments in the participants' applicable standard offer retail rate schedule will continue to apply. The proposed EDR will apply discounts on electric bills specific only to the qualifying additional load of participating customers. Economic Development is defined as new or expanding business operations that build new facilities. The discounts for Economic Development will be 20% in Year 1, declining to 2.5% in Year 5, and terminating after Year 5. Economic Redevelopment is defined as new or expanding business operations that occupy existing vacant facilities. The discounts for business expansion that qualifies as Economic Redevelopment will be 30% in Year 1, declining to 5% in Year 5, and zero after Year 5.

III. REVENUE REQUIREMENT.

A. Requested Revenue Increase.

Q. What is the overall revenue increase being requested by TEP?

A. TEP is requesting a $109.5 million increase to test year adjusted non-fuel revenues, which when compared to test year adjusted retail revenue is a 12.0% increase. However, that is not a complete description of the proposed increase when compared with rates presently being paid by customers; that include a PPFAC rate of $0.00682 per kWH that went into effect in April 2015. If the test year adjusted revenues reflected a full year with the present

PPFAC rate in effect the increase would be offset by a proposed $42.2 million reduction in fuel. When comparing the proposed revenues to test year adjusted revenues with the present PPFAC applied for the entire period, TEP's request would increase revenue by approximately $67.3 million, or 7.1%.

Summary of Requested Retail Rate Impact			
		Sch. A	
(in Millions)		Adjusted Test Yr. W/ Proposed Fuel ($303.9M)	Adjusted Test Yr. Sales W/ Current Fuel Rates ($346.1M)
	Retail Revenue	$ 909.3	$ 951.5
	Non-Fuel Increase	$ 109.5	$ 109.5
Less:			
	Fuel Reduction (to get to $303.9M)	$ -	$ (42.2)
	Net Increase in Retail Revenue	$ 109.5	$ 67.3
	Percentage Increase	12.0%	7.1%
Presented another way:			
	Proposed Retail Revenue	$ 1,018.8	$ 1,018.8
Less:			
	TY Retail Revenue w/alt. PPFAC rates	$ (909.3)	$ (951.5)
	Net Increase	$ 109.5	$ 67.3
	Percentage Increase	12.0%	7.1%

B. Summary of Schedules.

1. "A" Schedules.

Q. Please describe the information contained on summary Schedule A-1.

A. Schedule A-1 provides a summary of the increase in revenue requirement that the Company is requesting. Lines 1 through 8 of Schedule A-1 present the data used in determining the Company's revenue requirement. The data presented pursuant to three valuation methodologies: (1) original cost rate base ("OCRB"); (2) reconstruction cost new less depreciation ("RCND"); and (3) fair value rate base ("FVRB"). FVRB is determined by adding together OCRB and RCND rate base amounts and dividing that total by two. This gives equal weight to both methods when determining the fair value amount. This method of determining the fair value is consistent with prior Commission practice.

Q. Please describe the information contained on Schedule A-2.

A. Schedule A-2 presents a summary of the results of operations for the Test Year and the two prior calendar years, compared with the projected year. Lines 1-16 of Schedule A-2 set forth the summary of operations for the Test Year. Schedule A-2 also presents projected results of operation for the year ending December 31, 2015 under the headings "present rates" and "proposed rates".

Q. Please describe the information contained on Schedule A-5.

A. Schedule A-5 presents a summary of changes in financial position for the Test-Year and the prior two calendar years. This schedule also includes the projected financial position as of June 30, 2016.

2. **"B" Schedules.**

Q. Please describe the information on Schedule B-1.

A. Schedule B-1 provides a summary of the company's OCRB and RCND rate base as of the end of the Test-Year, including the related pro forma adjustments to rate base. Rate base is comprised of net utility plant, certain regulatory assets and working capital, with deductions from rate base for accumulated deferred income taxes ("ADIT"), customer advances for construction, and customer deposits. The schedule also reflects the adjusted OCRB and RCND rate bases for the Total Company and what is jurisdictional to the Commission.

Q. Please explain briefly the information contained on Schedule B-2, B-3 and B-4.

A. Schedule B-2 shows the pro forma adjustments to the OCRB. The information presented includes the actual per-book balances (as prepared under Generally Accepted Accounting Principles or "GAAP") and the end of the Test-Year, pro forma adjustments, and the adjusted balances on a Total Company and Commission jurisdictional basis. Schedule B-3 provides the same detail by functional account classification as shown on Schedule B-2, except that it is shown on an RCND basis. Schedule B-4 shows the plant in service accounts on a RCN and RCND basis.

Q. Please explain briefly the terms RCN and RCND.

A. The ACC has defined RCND in Title 14 as:

> An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the Test-Year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the

accounts of the public service corporation, shall be increased to a reconstruction new basis. (A.A.C. R14-2-103(A) (3) (n)).

The RCN is the estimated cost of constructing the company's property in today's cost levels; this is done through a trending study. RCND refers to the net amount after deducting accumulated depreciation and amortization.

Q. Please explain briefly the basis for the determination of the RCND rate base.

A. Plant in service and customer advances for construction reported at RCN are summarized from the results of a detailed plant cost trending study. The accumulated depreciation and ADIT reported on a RCN basis have been computed by multiplying the corresponding original cost balance by a ratio, the numerator of which is gross RCN of depreciable plant, and the denominator of which is gross original cost of depreciable plant. All other rate base elements are reflected at original cost.

Q. Please describe the plant cost trending study.

A. The trending study was prepared to establish an index number that represents a ratio between the cost of an item at its in-service date ("or "Vintage"), and its cost at a base period. The indices are applied to the Company's original cost to estimate the reconstruction or reproduction cost at current cost levels. For example, the RCN value for 2009 Vintage assets in Account no. 362, Distribution plant – Station Equipment was computed as follows:

2014 Index Value Acct 362 / 2009 Index Value

=2014 Cost Index for Acct 362

Original Cost of 2009 vintage assets in Acct. 362 X 2014 Cost index for Acct 362

=RCN for Acct 362 (current costs)

For most accounts, the Handy – Whitman Index of Public utility Construction Costs for the Plateau Region was employed (based on the most recently available index numbers). For plant accounts 303, 391, 393, 394 and 398 the "Marshall Valuation Service cost Index" was used. For plant accounts 392, 395, 396 and 397, the Bureau of Labor Statistics producer price index was used.

Once the RCN value has been established it is then multiplied by a net book value percentage. The net book value percent is simply the original cost less accumulated depreciation divided by the original cost.

For example, assume the Company has distribution station equipment with an original cost of $100,000, and accumulated depreciation of $50,000. The original cost less accumulated depreciation would be $50,000 ($100,000 - $50,000). Also, assume the Vintage year is 2009 and has a RCN value of $117,500. Multiplying the RCN by the net book value percent yields RCND of $58,750 ($117,500 x 50%=$58,750).

Q. What is the Handy – Whitman Index?

A. It is an index of public utility construction costs that has been published continuously since 1924 by Whitman, Requardt and Associates of Baltimore, Maryland. The Handy – Whitman Index is a well-recognized, widely used and generally accepted method for measuring differences in property values for insurance and other purpose, including the valuation of public utility property for rate case purposes.

The Handy – Whitman Index is comprised of index values for various accounts prescribed by the FERC Uniform System of Accounts and for six geographical divisions

of the country, including the Plateau Division, in which Arizona and New Mexico are located. These index numbers result from a comparison of the current prices of materials, labor, and equipment to prices in a base year. Index values are determined for each year as of January 1 and July 1.

The index values are used to determine cost trend factors, which are then applied to know original costs of similar plant and property to determine the fluctuation in cost between the date of installation and the date of valuation.

Q. What is the Marshall Index?

A. The Marshall Index, prepared by the firm of Marshall & Swift, is an index of construction cost trend valuations. It was used in the development of costs reported in the RCND Study for those plant accounts not reported by Handy – Whitman. The Company used the Bureau of Labor producer price index when neither the Handy – Whitman nor the Marshall indices were available.

Q. Please explain Schedule B-5.

A. This Schedule summarizes the computation of the allowance for working capital that the Company is requesting for inclusion in rate base in this rate case. I explain these computations later in my testimony.

Q. Why are the original costs and RCND costs of working capital the same in Schedule B-5?

A. They are the same because the original costs are at current prices or have been adjusted to current prices, meaning they have not been significantly affected by inflationary factors.

3. "C" Schedules.

Q. Please explain Schedule C-1.

A. Schedule C-1 shows the Income Statement as prepared in accordance with GAAP for the twelve months ending June 30, 2015, the Test-Year in the case. It also summarizes the effect of proposed pro forma adjustments made to operating revenues and expenses, and the resulting adjusted net operating income.

Q. What is the purpose of Schedule C-2?

A. Schedule C-2 presents the detailed pro forma adjustments that reflect the full annual impact of operation changes, annualizations, normalizations, and other adjustments made to revenues and expenses. I will discuss these adjustments in detail later in my testimony.

Q. What is the purpose of Schedule C-3?

A. Schedule C-3 calculates the revenue conversion factor. This recognizes that the Company will need to "gross up" the net income deficiency to account for income taxes and additional bad debt.

C. Pro Forma Adjustments.

Q. Please explain what a Pro Forma Adjustment is?

A. Public utility rates are based on the prudently incurred costs of providing safe, reliable service. The Company's revenue requirement is based on an historical Test-Year that reflects a level of operating revenues, expenses and net plant investment that occurred during that period. Because a historical Test-Year is being used, it creates a critical need to adjust the recorded Test-Year for actual occurrences not expected to recur or for events

that are expected to occur but did not exist during the Test-Year. Such adjustments may be in the form of eliminations, annualizations or normalizations.

Q. What is an Elimination Adjustment?

A. Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service; thus, not eligible for reflection in revenue requirements.

Q. What is an Annualization Adjustment?

A. Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments recognize that certain events that happen in a Test-Year are ongoing and must be spread over the entire Test-Year period. Examples are annualizations of revenues to reflect end-of-Test-Year customer levels and annualization of depreciation expense to reflect end-of-Test-Year plant investments and any proposed new deprecation rates. The Annualization adjustment synchronizes the Test-Years investments, revenue and cost relationships.

Q. What is a Normalization Adjustment?

A. Normalization adjustments reflect that the recorded Test-Year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the Test-Year may not be viewed as "normal," thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in such instances when a Test-Year level of revenues or expenses is not representative of what would be expected on an on-going

basis. Examples in this case include the adjustment for bad debt expense, the overtime factor implicit in the payroll adjustment, and the adjustment to normalize the level of outside legal expense.

D. Rate Base Pro Forma Adjustments.

1. Springerville Leasehold Improvements.

Q. Please explain the Springerville ("SGS") Leasehold Improvements Adjustment.

A. Over the years, TEP has made numerous capital improvements to SGS Unit 1; these improvements have been made in order to keep the facilities in good operating condition and to improve operating efficiencies at SGS as it provided service to our customers. This adjustment is necessary to continue the recovery of the remaining book value of those improvements that have been reclassified to a regulatory asset at the termination of the lease. The details of this request are in the direct testimony of TEP witness Kentton Grant.

Q. How were SGS leasehold improvements treated in TEP's last rate case?

A. The improvements were included in rate base at their original cost, net of accumulated amortization. Amortization of the leasehold improvements was also included in the Company's non-fuel revenue requirement using a 10-year amortization period.

Q. Is TEP requesting a change to the amortization period approved in the previous rate case?

A. No. TEP is requesting to continue the amortization period established and approved in the last case.

2. Springerville Unit 1 Lease Equity.

Q. Please explain the SGS Unit Lease Equity adjustment.

A. TEP is requesting the recovery of its investment in the SGS Unit lease equity originally made in 2006. The adjustment is necessary to bring the book value as of the end of the test year up to the unrecovered net investment of $42.7 million. The details of this request are in the direct testimony of TEP witness Kentton Grant.

3. Asset Retirement Obligation.

Q. Please explain the Asset Retirement Obligation ("ARO") Adjustment.

A. This adjustment is necessary to remove the balances of ARO assets reported in Plant in Service. ARO assets exist only for those assets where there is a *legal* obligation to physically remove the assets at the end of their useful lives. In this rate case, the expected costs to remove the related assets from Plant in Service are implicit in the Negative Net Salvage component of our depreciation rates, and used in the preparation of the depreciation annualization adjustment.

Q. Is this adjustment consistent with the treatment of ARO in TEP's last rate proceeding?

A. Yes.

4. Post-Test-Year Plant.

Q. Please describe your proposal for including Post Test-Year Plant.

A. TEP has adjusted its ACC jurisdictional rate base to include approximately $51.8 million of used and useful plant additions that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2015. The post test-year amount being requested only reflects the portion of those facilities invested in prior to the end of the test year. These projects will be benefiting customers by the time new rates are effective.

Q. Has the Commission allowed the use of Post Test-Year Plant before?

A. Yes. The Commission approved including Post-Test-Year Plant for UNS Electric in the 2013 UNS Electric Rate Order. The Commission has also allowed Post-Test-Year Plant in numerous other cases, including: TEP in Decision No. 73912 (June 27, 2013); Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012), Rio Rico Utilities, Inc., in Decision No. 67279 (October 5, 2004); Arizona Water Co., in Decision No. 66849 (March 19, 2004); and Bella Vista Water Co., Inc., in Decision No. 65350 (November 1, 2002).

Q. What are the benefits of including Post Test-Year Plant in rate base?

A. It more closely aligns the recovery of costs with the benefits that are currently being provided to existing customers. It also lowers the cost to customers by limiting the amount of Allowance For Funds Used During Construction ("AFUDC") charged to the assets, thereby reducing the future depreciation and carrying costs associated with this plant. Additionally, the timely recovery of costs necessary to maintain a safe, reliable electric system is necessary to mitigate larger rate impacts that result from the use of historic test years combined with little to no increase in sales.

Q. Is this adjustment consistent with the treatment of Post Test-Year investments in TEP's last rate proceeding?

A. Yes.

5. Post-Test-Year Plant Renewables.

Q. Please describe your proposal for including Post Test-Year Plant Renewables.

A. TEP has adjusted its ACC jurisdictional rate base to include approximately $20.8 million of used and useful plant additions that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2016. The post test-year amount being requested reflects the portion of the facilities expected to be in service prior to the rate being established in this proceeding going into effect. This adjustment extends out an additional 12 months beyond the non-renewable post-test-year cut-off. This allows for the reflection of these renewable asset investments approved through the REST application process to be recovered through base rates as opposed to being recovered through the REST tracker. These projects will be benefiting customers by the time new rates are effective.

Q. Is this adjustment consistent with the treatment of Post Test-Year Renewable investments in TEP's last rate proceeding?

A. Yes.

6. Delayed Unitization.

Q. Please explain the Delayed Unitization Adjustment.

A. The adjustment for Delayed Unitization represents plant additions that were used and useful as of the end of the test year, but not part of the Balance in FERC Account 106,

Completed Construction not Classified, as of June 30, 2015. The Delayed Unitization adjustment represents additional costs incurred on previously unitized projects and projects that were completed as of June 30, 2015 that became known subsequent to test-year-end. Because these projects are used and useful, they should be included as part of test year rate base.

Q. Is this adjustment consistent with the treatment of Delayed Unitizations in TEP's last rate proceeding?

A. Yes.

7. Working Capital.

Q. What is working capital?

A. Working capital is generally viewed as investor funding of day-to-day operating costs, in excess of the balance of net utility plant reflected in rate base that is required for the provision of utility service.

Q. What are the items of working capital for which the Company requests a return?

A. The components of working capital that the Company is requesting be included in rate base are:

(i) Fuel Inventory;

(ii) Materials and Supplies;

(iii) Prepayments; and

(iv) Cash Working Capital.

As more fully explained later in my testimony, the amounts requested for rate base inclusion for fuel inventory, materials and supplies, and prepayments are based on test-

year recorded balances, adjusted to reflect normal levels. The cash working capital component was determined by the use of a lead-lag study.

Q. Please explain the Working Capital adjustment.

A. The Working Capital adjustment was computed in two parts. As indicated on page 2 of Schedule B-5, the first piece adjusts the recorded end-of-test-year balances for Fuel Inventory to reflect the targeted inventory day level as recommend by Staff in a prior rate case. Materials and Supplies, and Prepayments are adjusted to reflect the 13-month average balance, in recognition of the variability in the monthly balances of the accounts. These treatments are consistent with the treatment of such accounts in prior rate cases.

The second part of the Working Capital adjustment is the reflection in rate base of a measure of Cash Working Capital, developed through the preparation of a comprehensive lead-lag study.

Q. What is Cash Working Capital?

A. The receipt of customer revenues for the provision of service, and the disbursement of cash for the payment of the various costs of providing service, rarely occur simultaneously. This is the fundamental consideration underlying the concept of Cash Working Capital. Cash Working Capital is generally viewed as the component of working capital that represents the amount of invested cash required to pay day-to-day operating expenses incurred in rendering service to customers. It may either increase or decrease rate base. If the computation of Cash Working Capital produces a positive result, then it indicates that there is an additional investment for which a return is warranted. Thus, that amount is added to rate base. If the computation produces a negative result, then it implies non-investor funding of Cash Working Capital, requiring a

rate base deduction. In developing this adjustment, a comprehensive lead-lag study was prepared.

Q. What is a lead-lag study?

A. A lead-lag study is a detailed analysis of the dynamic movement of funds throughout the organization, between the receivable and payable balance sheet accounts and related revenues and expenses that are reflected in the operating income component of revenue requirements. The method is generally viewed as the most accurate measure of Cash Working Capital. The Commission has stated a clear preference for the use of lead-lag studies in support of requested cash working capital amounts reflected in rate base.

The focal point of all lead-lag studies is the "point of service". This is the instant in time at which customers receive service and, coincident therewith, the utility incurs the cost of providing that service. A lead-lag study measures the average length of time between the provision of service and the ultimate receipt of payment from the customer ("revenue lag"). The result is compared with the average length of time between the point at which the utility incurs a cost of providing that service and the date upon which it makes the related cash disbursement ("payment lead" if payment precedes the cost benefit, or "payment lag" if the payment occurs after the cost benefit). Cash Working Capital reflects the effect on costs of service of the difference between the revenue lag and payment leads or lags.

As may be seen on page 3 of Schedule B-5, a lead-lag study computes the Cash Working Capital associated with each component of cost of service. The revenue lag is constant for all cost categories. The various major expenses are analyzed separately for purposes of developing a specific payment lead or lag. Once the applicable expense lead or lag is known, it is compared with the revenue lag to determine the net lead or lag for that study

category. After dividing the net lead or lag by 365 days to arrive at an annual percentage factor, the result is multiplied by the corresponding adjusted test-year expense amount to quantify the Cash Working Capital requirement associated with that cost of service item. Consistent with past Commission policy, the effect of non-cash expenses such as depreciation and deferred income taxes are reflected in the study at a zero requirement.

Q. How was the average revenue lag computed?

A. The revenue lag is comprised of three distinct parts: the service lag, the billing lag, and the customer payment lag.

The service lag is measured from the midpoint of the period of service to the end of the period, the date upon which meters are read. A key underlying assumption is that service is taken uniformly throughout the period. With each customer being billed under 12 monthly billing cycles during the year, the average service lag is computed as 15.21 days [365 days / (12 X 2)].

The billing lag is typically measured from the meter read date to the date customer bills are prepared and balances entered into accounts receivable. The billing lag was computed based on actual meter read dates and bill mailing schedules used by TEP during the test-year.

The customer payment lag is measured from the point at which the customer bill enters accounts receivable to the date that either a payment is received or the account is written off as uncollectible. The lag was determined by computing the average accounts receivable turnover for the 12 months during the test-year. The accounts receivable turnover factor is calculated by the average daily balance of accounts receivable over the average daily revenues billed

Q. How were the payment leads and lags computed?

A. The payment leads and lags were developed based on analyses of actual payment history, contractual and statutory payment dates, and samples of expenditures.

Q. What was the overall result of the lead-lag study?

A. The study showed that there was negative Cash Working Capital and a corresponding decrease was made as a pro forma adjustment to rate base.

Q. Are these adjustments consistent with the treatment of Working Capital in TEP's last rate proceeding and approved by the Commission?

A. Yes.

E. Revenue and Expense Pro Forma Adjustments.

1. Lost Fixed Cost Revenue.

Q. Please explain the Lost Fixed Cost Revenue Adjustment.

A. This adjustment removes all revenues collected under the Lost Fixed Cost Recovery mechanism. These revenues are not collected as part of base rates, so they must be excluded from Test-Year revenues in order to calculate new base rates.

2. Environmental Cost Adjustor.

Q. Please explain the Environmental Cost Adjustor Adjustment.

A. This adjustment removes all revenues collected under the Environmental Cost Adjustor mechanism. These revenues are not collected as part of base rates, so they must be excluded from Test-Year revenues in order to calculate new base rates.

3. Renewable Energy Standard & Tariff ("REST") and Demand-Side Management ("DSM").

Q. Please explain the REST and DSM Adjustment.

A. This adjustment excludes from Test-Year revenue and expense activity directly related to the Renewable Energy Standard & Tariff ("REST") and Demand-Side management ("DSM") adjustor programs. These programs have separate funding mechanisms and should thus be excluded from Test-Year revenue and expenses in the process of establishing retail base rates.

4. Non-Retail & Non-Recurring Revenue.

Q. Please explain the Non-Retail Revenue and Non-Recurring Revenue adjustments.

A. This adjustment is necessary to exclude revenues collected during the test year that will not reoccur in the years when new rates will be in effect.

5. Springerville Units 3 & 4.

Q Please explain the Springerville Units 3 & 4 adjustment

A. TEP operates units 3 & 4 of the Springerville Generating Station on behalf of the unit owners, Salt River Project and Tri-State Generation and Transmission Association. Therefore, it is necessary to remove all expenses and associated reimbursements related to operating those facilities on their behalf. The result of this adjustment is to assure that the customers of TEP are not incurring any cost related to those operations and receive the benefit of administrative, common and other cost allocated to those facilities.

Q. Is this adjustment consistent with the treatment of Springerville Units 3 & 4 revenue and expenses in TEP's last rate proceeding?

A. Yes.

6. Sales of SO2 Allowances.

Q. Please explain the Revenues on Sale of SO2 Allowances Adjustment.

A. The Company is allowed to retain 50% of the revenues from the sale of SO2 allowances. The balance is credited to the PPFAC for the benefit of retail customers. The adjustment is necessary to remove the 50% being retained by the Company from test-year results.

Q. Is this adjustment consistent with the treatment of Sales of SO2 Allowances in TEP's last rate proceeding?

A. Yes.

7. Sales for Resale.

Q. Please explain the Sales for Resale Adjustment.

A. These adjustments are necessary because the revenue associated with short-term wholesale sales is recorded and 100% of that is also booked as a PPFAC regulatory liability (ultimately to credit customers through the PPFAC). There are also expenses associated with producing those revenues and those are expensed as incurred. Without adjustment the profit on those sales would flow through the income statement. Therefore an adjustment is made to the Company's actual books to bring the expenses up to the revenue level.

By making that adjustment, there is no operating income from wholesale transactions.

That "profit" is maintained in the PPFAC regulatory liability, which is then credited to customers through the PPFAC process. So the PPFAC rate reflects any profit in wholesale transactions and reduces the ultimate cost to customers. Therefore, we take the cost and the revenue out of the test year (which zero themselves out) because the profit on short-term wholesale transactions is already reflected in the PPFAC rates, and the total average cost of PPFAC eligible expenses being passed along to customers.

In addition long-term wholesale sales must be excluded from jurisdictional revenue as they are not related to the recovery of cost within jurisdictional base rates.

Q. Is this adjustment consistent with the treatment of Sales for Resale in TEP's last rate proceeding?

A. Yes.

8. <u>Power Supply Management Agreements.</u>

Q. Please explain the Power Supply Management Agreement Adjustment.

A. The Company provides coordination of wholesale energy supplies, energy scheduling and management of ancillary services for non-retail load within the TEP control service area. The adjustment is necessary to remove the revenues associated with these agreements, as well as the proportional cost associated with providing these services. By providing these services, TEP is reducing the cost of power supply management to its retail customers.

Q. Is this adjustment consistent with the treatment of Power Supply Management Agreements in TEP's last rate proceeding?

A. Yes.

9. Base Cost of Fuel & Purchased Power.

Q. Please explain the Base Cost of Fuel & Purchased Power Adjustment.

A. The adjustment is necessary to insure that the fuel, purchased power and purchased transmission costs that are eligible to be reconciled through the PPFAC process ("PPFAC-eligible costs") are equivalent to the revenues reflected in TEP's filing – and thus have no incremental effect on adjusted operating income in this case.

The adjustment is establishing the average base cost of fuel, purchased power and purchased transmission being requested within retail rates. The projected rate is being supported by and explained in Company witness Michael Sheehan's Direct Testimony. This rate was applied to customer-annualized and weather-normalized sales to come up with the amount of PPFAC-eligible costs and revenue to be included within TEP's filing. This represents TEP's best present estimate of the average per-kWh cost of PPFAC-eligible costs to be charged to customers when the rates established in this proceeding go into effect.

Q. Is this adjustment consistent with the treatment of Base Cost of Fuel & Purchased Power in TEP's last rate proceeding?

A. Yes. The resulting outcome is consistent with prior treatment and approval. In past filings this was an incremental adjustment to test year levels after removing revenues and cost associated with non-jurisdictional activity. In this filing TEP has simplified the adjustment in its cost of service model, by simply removing all jurisdictional and non-jurisdictional revenue and expenses related to fuel, purchased power & purchased transmission incurred during the test year – and replacing it with the entire pro-forma jurisdictional level. The end result is the same, just a bit easier to follow in the work papers and supporting materials.

10. Springerville Unit 1.

Q. Please explain the Springerville ("SGS") Unit 1 Adjustment.

A. As explained in the direct testimony of Company witness Kentton Grant, TEP has become the owner of a 49.5% undivided interest in Springerville Unit 1. However, TEP has all the cost attributable with operating 100% of the unit included in its test-year unadjusted expenses. This adjustment is necessary to remove those cost attributable to the other 50.5% of SGS Unit 1.

The adjustment doesn't include the reduction of test year property tax expense or depreciation. These amounts are removed from TEP's retail cost of service in those individual adjustments, by excluding the 50.5% portion of SGS Unit 1 from the plant values being used to calculate those pro forma levels.

11. Overhaul & Outage Normalization.

Q. Please describe the Overhaul and Outage Normalization Adjustment.

A. Generating overhauls are quite costly and do not occur at regular annual intervals; thus, the maintenance expense recorded in any given year is not representative of an average annual cost. This adjustment is intended to reflect in test-year maintenance expense a normal annual level of plant overhaul and outage costs. The adjustment includes an estimated recurring level of outage expense for the newly acquired Gila River facility and that amount is discussed in the direct testimony of Company witness Michael Sheehan. In addition, the adjustment excludes cost related to the 50.5% share of SGS unit 1 not owned by TEP and San Juan Unit 2, scheduled to be non-operational by the end of 2017.

Q. How was the adjustment calculated?

A. As was done in a similar adjustment filed in the last TEP rate case, this adjustment reflects the actual frequency and incremental cost of major and minor plant overhauls at each generating unit during recent years and forecasted for future years. This adjustment also excludes outage expenses related to San Juan Unit 2, which will no longer be serving retail customers after the calendar year 2017. With that data, a normal annual cost level was computed, with the adjustment being the difference between that amount and such costs recorded during the test year.

Q. Is this adjustment consistent with the treatment of Overhaul and Outage Normalization in TEP's last rate proceeding?

A. Yes.

12. <u>Rate Case Expense.</u>

Q. Please explain the Rate Case Expense adjustment.

A. TEP is estimating that it will incur incremental outside services rate case expense in this proceeding. TEP is requesting over a period of three years, recovery of the excess of these costs over test-year recorded rate case amortization expense.

Q. Can this cost estimate be revised and updated prior to the Commission's final decision in this case?

A. Yes. A majority, if not all, of these costs will be known and measureable prior to the closure of the docket in this case and can be revised prior to the final decision being rendered.

13. Injuries and Damages Expense.

Q. Please explain the Injuries and Damages Expense Adjustment.

A. The Injuries and Damages Expense adjustment normalizes the test-year expense to reflect the average annual expense.

Q. Is this adjustment consistent with the treatment of Injury and Damage Expense in TEP's last rate proceeding?

A. Yes.

14. Membership Dues.

Q. Please explain the Membership Dues Expense adjustment.

A. This adjustment removes the portion of membership dues paid to Edison Electric Institute for legislative advocacy, and other dues paid to organizations that have been voluntarily excluded from pro forma operating expenses for purposes of this rate case.

15. Bad Debt Expense.

Q. Please explain the Bad Debt Expense Adjustment.

A. Bad Debt Expense is adjusted to a level reflective of final, pro forma weather-normalized, customer-annualized test-year operating revenues, and the average percentage of bad debt expense experienced during the past three years.

Q. Is this adjustment consistent with the treatment of Bad Debt Expense in TEP's last rate proceeding?

A. Yes.

16. Asset Retirement Obligation Expense.

Q. Please explain the Asset Retirement Obligation Expense Adjustment.

A. Consistent with the removal of ARO assets from rate base, as previously described, this adjustment removes from test-year operating expense the corresponding ARO depreciation and accretion expense. Estimated asset removal costs are now included as Negative Net Salvage in the new depreciation rates proposed by Dr. White and used in the depreciation annualization adjustment.

17. Springerville Common Facilities Lease.

Q. Please explain the Springerville Common Facilities Lease adjustment.

A. This adjustment is necessary to reflect the capital lease associated with the Common Facilities at Springerville still remaining as an operating expense – based on the levelized annual lease expense. This adjustment is consistent with the treatment of this lease in TEP's prior proceedings and required by Commission rule, which does not allow for rate base treatment of capital leases.

18. TEP Headquarters - Retail Space.

Q. Please explain the TEP Headquarters – Retail Space Adjustment.

A. With respect to the unoccupied retail space (approximately 12,000 square feet) at the Company's headquarters; TEP is including an equivalent rental amount of $250,000. This amount is being included as a dollar-for-dollar reduction to the jurisdictional cost of service. The proposed adjustment is in accordance with Section 20.1 of the Settlement Agreement approved in TEP's last general rate proceeding, Docket No. E-01933A-12-0291.

19. Credit Card Processing Fees.

Q. Please explain the Credit Card Processing Fees Adjustment.

A. The Company is proposing to include the majority of the cost associated with providing credit card payment service within its cost of service. Presently, 100% of third-party transactions fees associated with credit card payments are paid directly to the third-party vendor by the customer making the payment. TEP is requesting to reduce those costs presently charged to credit card paying customers to $1.00 per transaction, limited to one transaction per month for up to $700. Therefore a pro forma adjustment is necessary to include the remaining cost of providing this service in test year expense levels. The details of this proposal and why TEP is requesting such a policy change are explained in the Direct Testimony of TEP witness Denise A. Smith.

Q. Does this conclude your testimony?

A. Yes.

Exhibit DJD-1

Line	Utility	Service Characteristics	Demand Interval	Ratchet	Monthly Minimum	Customer Charge	Demand Charge (per kW, except where kVA indicated)								
								Seasonal		Seasonal Time of Use					
										On Peak		Off Peak			Max
							Year round	Summer	Winter	Summer	Winter	Summer	Winter		Demand
1	Alabama Power	Single Phase	15 min	None	Base+Demand Charge	$14.50	$ 1.50								
2	Alaska Electric Light and Power Company	Single Phase	Not specified	None	Customer Charge	$11.49		$ 11.11	$ 6.72						
		Single Phase				$27.00									
3	Albemarle Electric Member Corp	Three Phase	15 min	None	Facilities Charge	$54.00				$	13.50				$ 2.25
4	Arizona Public Service Co. - APS	Single Phase	60 min	None		$16.90				$ 13.50	$ 9.30				
5	Black Hills - South Dakota	Single Phase	15 Min	None	Customer Charge	$13.00									$ 8.10
6	Black Hills - Wyoming	Single Phase	15 Min	None	Customer Charge	$15.50	$ 8.25								
		Single Phase				$30.00									
7	Carteret-Craven Electric Member Corp	Three Phase	15 min	None	Customer Charge	$57.30				$ 11.95	$ 9.95	$	-		
		Single Phase				$32.00									
8	Central Electric Membership Corporation	Three Phase	15 min	None	Facilities Charge	$58.00				$ 8.25	$ 7.25	$	3.15		
9	Central New Mexico Electric Coop., Inc			None	Customer Chage	$18.75	$ 10.00								
10	Consolidated Electric Coop		Not specified	None	Not specified	$25.00	$4.50/kW above 30kW								
		Premanant resident				$17.50									
11	Delaware County Elec Coop Inc	Second home	15 min	None	Service Charge	$22.50	$1.00/kVA above 10 kVA								
12	Duke Energy Carolinas, LLC	Single/Three phase	30 min		Facilities Charge	$13.38				$ 7.77	$ 3.88	$	-		
13	Duke Energy Carolinas, LLC		30 min	None	Facilities Charge	$13.38	$ 1.78								
14	Duke Energy Carolinas, LLC		30 min	None	Facilities Charge	$13.38	$ 1.48								
		Single Phase				$14.13									
15	Duke Energy North Carolina	Three Phase	15 min	None	Customer Charge	$22.84		$ 4.97	$ 3.69						
16	Duke Energy Ohio	Single	15 min	Yes	Customer Charge	$6.00									
		Single Phase				$9.60									
17	Duke Energy South Carolina	Three Phase	15 min	None	Facilities Charge	$18.60		$ 5.20	$ 3.89						
18	Edgecombe-Martin County E M C			None		$31.00				$ 8.75	$ 8.00	$	-		
19	Fort Collins	Single Phase	15 min	None	Customer Charge	$5.07	$ 2.26								
20	Georgia Power	Single/Three phase	30 min	None	Service Charge	$10.00	$ 6.53								
21	Greenville NC (as of Aug 2015)		15 min	None	Facilities Charge	$19.47	$ 7.94								
		Single Phase				$15.00	$1.00/kVA for transformer above 25 kVA (single phase)								
22	Jackson Electric Coop.	Three Phase		None	Customer Charge	$1.00/kVA									
23	Kentucky Utilities Company		15 min	None	Service charge	$10.75		$ 13.05	$ 3.70						
		Single Phase				$15.09									
24	Kinston, North Carolina (City of)	Three Phase	15 min	None	Service Charge	$27.09		$ 10.15	$ 7.89						
25	Lakeland Electric	Single phase	30 min	None	Customer charge, Demand charge, plus Adjustments	$9.50	$ 4.80								
26	Longmont, Colorado (City of)		15 min	None	Customer Charge	$15.40	$ 5.75								
27	Louisville Gas and Electric Company		15 min	None	Service Charge	$10.75		$ 12.38	$ 3.25						
28	Loveland, Colorado (City of)		15 min	None	Base Charge	$21.10		$ 9.00	$ 6.90						
29	Medina Electric Cooperative, Inc.	Single/Three phase	kVA rate	None	Customer Charge	$27.50	$1.50/kVA for billing kVA over 15 kVA								
30	Mohave Electric Cooperative, Inc.	Single Phase	15 min	None	Customer Charge	$21.50	$ 8.50								
31	Ohio Power Company	Singel Phase	on peak avg	None	Customer Charge	$10.02									
32	Pee Dee Electric Member Corp		Not specified	None	Facilities Charge	$25.00				$ 8.25	$ 6.80	$	-		$ 2.45
		Single-Phase				$30.00									
33	Piedmont Electric Member Corp	Three-Phase	15 Min	None	Facilities Charge	$69.45				$ 15.95	$ 14.95	$	1.25		
34	Public Service Company of Colorado (Xcel)		15 min	None	Service and Facility Charge plus Demand Charge	$12.25		$ 8.57	$ 6.59						

Line	Utility	Service Characteristics	Demand Interval	Ratchet	Monthly Minimum	Customer Charge	Demand Charge (per kW, except where kVA indicated)							Max Demand
								Seasonal		Seasonal Time of Use				
										On Peak		Off Peak		
							Year round	Summer	Winter	Summer	Winter	Summer	Winter	
35	Salt River Project, Arizona	Single/Three phase	30 min	None	Service Chage	<200 Amp Service Summer: $30.94 Winter: $32.44 >200 Amp Service Summer: $43.94 Winter: $45.44				0-3kW: $8.03 3-10kW: $14.63 >10kW: $27.77 July&August 0-3kW: $9.59 3-10kW: $17.82 >10kW: $34.19	0-3kW: $3.55 3-10kW: $5.68 >10kW: $9.74			
36	Santee Cooper, South Carolina		Not specified	None	Customer Charge	$22.00	$ 17.19							
37	Smithfield, North Carolina (Town of)	Single Phase	15 Min	None	Customer Charge	$15.95				$	6.24	$	-	
38	Swanton Village, Vermont	Single Phase	15 min	12 month 85%	Customer charge plus 85% of highest demand charge	$25.05	$ 6.38							
39	Tri-County Electric Coop, Inc (Florida)	Single Phase	Not specified	None	$28.00	$23.00 $22.00	$ 7.00							
40	Vigilante Electric Coop, Inc	Single Phase	Not specified	None	Base Charge	$29.50	$0.50/kVA for billing kVA over 15 kVA							
41	Virginia Electric & Power Company		30 min	None	Customer Charge	$16.53		$ 8.32	$ 4.87					
42	Virginia Electric & Power Company		30 min	None	Customer Charge	$7.00	$ 2.059							
43	Virginia Electric & Power Company		30 min	None	Customer Charge	$12.00				$ 5.682	$ 3.946			

Direct Testimony of Craig A. Jones

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01933A-15-____

Direct Testimony of

Craig A. Jones

on Behalf of

Tucson Electric Power Company

November 5, 2015

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Exhibit CAJ-2 Bill Impact Summary
Exhibit CAJ-3 Clean version of Tariffs
Exhibit CAJ-4 Redlined version of Tariffs
Exhibit CAJ-5 LFCR - Plan of Administration (Clean and redline)
Exhibit CAJ-6 ECA - Plan of Administration (Clean and redline)

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Craig A. Jones. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP" or the "Company"), a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy") as the Director of Pricing. As the Director of Pricing, I am responsible for various rate-related matters including monitoring and coordinating the determination of customer pricing options with any necessary support to justify the creation of the various rate structures for all the regulated subsidiaries of UNS Energy, including TEP, UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"). This includes overseeing the development of the cost-of-service analysis and rate design in general rate cases.

Q. Please describe your educational background.

A. I graduated from the University of Missouri Columbia in December 1980 with a Bachelor of Science Degree in Agricultural Engineering. In May 1981, I received a Bachelor of Science Degree in Agricultural Mechanization. I have completed much of the course work required for a Master's Degree in Agricultural Engineering at the University of Missouri Columbia. I am qualified as an Engineer-in-Training under the laws of the State of Missouri.

Q. Please describe your professional background and experience.

A. In February 1983, I joined the Staff of the Missouri Public Service Commission as a Rate Engineer. My responsibilities included analyzing and making recommendations relating to

purchased gas adjustment filings, actual cost adjustment filings, rate cases, certificate of service applications, intrastate pipeline applications and applications to establish new local distribution systems. I left the Missouri Public Service Commission in December 1994 to take a position with the New York State Electric and Gas Corporation ("NYSEG"). My responsibilities at NYSEG included establishing prices to be used in "repackaged" contract offerings, training co-workers and end-users with respect to the application of new rates and service concepts, and complying with regulatory filing requirements, including the calculation and filing of the monthly gas cost adjustment filings with the New York Public Service Commission.

I left NYSEG in April 1998 to take a position as Rates Manager with Citizens Energy Group (formerly Citizens Gas & Coke Utility) ("Citizens") in Indianapolis, Indiana. In March 2004, I was promoted to Manager Rates and Regulatory Affairs. I was responsible for various rate-related matters associated with both the natural gas and steam utilities operated by Citizens, including the annual filings for approval of a fuel cost adjustment for the steam utility and the development of the monthly gas cost adjustment filings, various miscellaneous tariff filings, special contracts, and numerous other rate-related activities for the gas and steam utilities, including cost of service and rate design in general rate cases.

In November 2009, I left my position at Citizens and joined TEP as the Manager of Pricing. I was promoted to Director of Pricing in September 2015. Since joining TEP, I have provided pre-filed direct testimony and live testimony in the UNS Gas 2011 general rate case (Docket No. G-04204A-11-0158, Decision No. 73142), and pre-filed testimony in TEP's last general rate case (Docket No. E-01933A-12-0291) and UNS Electric's 2012 and 2015 general rate cases (Docket Nos. E-04204A-12-0504, Decision No. 74235 and E-04204A-15-0142). I have actively participated in the Arizona Corporation Commission's

("Commission") Decoupling Workshops, Line Extension reviews and the filing of TEP's Community Solar tariff and other Pricing and Regulatory activities.

Q Have you previously testified before any other regulatory agencies?

A. Yes. I testified before Indiana Public Service Commission on numerous occasions, including in Cause Nos. 41969-FAC01-FAC15, 41969-FAC03(S1), 41969-FAC06(S1), 41605, 41824, 42578, 42726, 42767, 43025, 43463 37399-GCA68, 37399-GCA68(S1), 37399-GCA69, and 37399-GCA77. I also testified before the Missouri Public Service Commission on several occasions regarding rates, tariffs, and certificate applications.

Q. Are you sponsoring any schedules?

A. I am sponsoring the "G" and "H" Schedules, which summarize the class cost-of-service study ("CCOSS"), rate design, and proof of revenue in this proceeding.

Q. Could you please summarize your Direct Testimony?

A. First, I detail TEP's CCOSS. This study is necessary in order to determine an appropriate total cost to serve each class. The goal of the CCOSS is to determine fair cost allocation and rate design among the customer classes based on the principle of cost causation and the principle of matching costs and revenues. Establishing which classes are responsible for which costs is the bedrock of designing rates. The Company's objective, by undertaking a CCOSS, is to confirm that proposed rates generate revenue that recover costs and provide an opportunity for the Company to earn a reasonable return on investment per customer class.

As part of TEP's CCOSS, I directed the development of an embedded cost study and a marginal customer cost study for the Company. Both studies are useful in developing rate designs that support and reflect valid price signals. The results of the embedded cost study

provide important guidance for the class allocation of revenues; while the embedded cost and marginal cost studies, taken together, help determine the level of specific charges to establish just and reasonable rates. For the embedded cost study, the Company has chosen the Average and Excess method to allocate demand costs, a commonly-accepted methodology used in the industry, including by Arizona Public Service Company ("APS"). By contrast, the Company's marginal cost study is a forward-looking study that focuses on the change in costs associated with a small change in the number of customers added to the system – or the cost to replace the current customer related infrastructure to continue service to an existing customer. As a result, the Company can propose rates designed to encourage efficient use of the TEP system and to establish basic service charges that send the right price signals to customers.

Second, I describe the Company's proposed rate design, including modifying existing rates to move toward parity and recover costs in a more equitable manner from all similarly situated customers – by shifting more of the fixed costs into fixed-rate components and to create rate classes that contain a more similar grouping of customers. I describe how TEP's proposed rate design can better align the Commission's policies and support the Company's need for fixed cost recovery, as well as reduce existing cross-subsidies within and between customer classes. To meet these objectives, and in light of the CCOSS results, my testimony explains how TEP proposes a lower percentage rate increase for classes presently paying significantly more than the system-average return on rate base, and a higher percentage rate increase for classes presently paying significantly less than the system average return on rate base. I also detail additional factors focused on in designing rates – including billing determinants, ratchets and consistency. My testimony also explains that the resulting bill impact is reasonable and consistent with the gradualism principle. Additionally, I set forth the bill impacts of these changes.

My testimony also describes TEP's proposal to increase the monthly basic service charges to levels that better match the minimum cost to serve the customer – including incorporating demand-related costs for those classes without a demand charge. The inclusion of some demand costs in fixed charges is consistent with the rule economists call the inverse elasticity pricing rule. That rule recognizes that efficient prices should be set at marginal cost and any additional revenue requirements should be recovered in the most inelastic portion of the rate schedule - in this case the basic service charge. The proposed rate design changes are needed to send customers more accurate price signals. With better price signals to customers and more appropriate fixed cost recovery for the Company the environment will be much more conducive to the promotion of energy efficiency ("EE") and distributed generation ("DG"), as well as the adoption of new technologies. In addition, these more efficient rates provide TEP a reasonable opportunity to earn its allowed return.

My testimony also addresses other rate design changes including: (1) elimination of the third and fourth rate tiers in the residential Rate R-01 and Rate R-201A; (2) the addition of a second tier to comparable time-of-use ("TOU") rates for both Residential and Small General Service rate classes (incenting customers to move their consumption from on-peak hours to off-peak hours in order to generate savings on their bills instead of being able to save on a per kWh basis by simply using more energy); (3) establishment of a charge for those customers who do not want an automated meter installed; (4) establishment of a new Medium General Service ("MGS") class; (5) changes to the minimums, maximums, power factor calculations and demand charges for certain classes; (6) the elimination of Rate LLP-14; (7) creation of a 138 kV rate that will contain only customers' service points that are taking service at transmission level voltage; and (8) revising the Community Solar rate.

In short, the Company seeks to modernize and update its rate design to address: (1) declining usage per customer; (2) low-use/no-use customers that are not paying an equitable share of the fixed costs to operate and maintain the TEP grid; and (3) lost-fixed cost revenues associated with energy efficiency and distributed generation.

Third, I address Lifeline rates. The Company proposes to simplify and reduce the number of Lifeline rates currently in place by offering two levels of discount to the five primary types of Residential customers. Currently, TEP has 27 Lifeline tariffs which contain multi-leveled percentage discount variations, numerous rate design variations and single monthly discounts (limited to a reduction of the bill to zero). Many of these tariffs have only 10 or less participating customers. The Company proposes to modify the current Lifeline Rates in a manner that allows the grouping of customers in an attempt to minimize the impact to a typical Lifeline customer.

Fourth, I discuss the "buy through" tariff the Company is proposing as required under the UNS Energy and Fortis Inc. ("Fortis") merger Settlement Agreement.[1] The Company does not support it, and in fact, is opposed to the implementation of this tariff. It allows for certain large customers to "cherry pick" currently available capacity resulting from short-term energy market conditions and will ultimately result in costs being shifted to the remaining customers.

Fifth, I provide bill impact comparisons by class by using "typical" usage amounts for each major rate class and applying that usage amount to the other similar sub-classes. This provides a more accurate comparison of current rates to proposed rates beyond what is provided in the "H" schedules, although the proposed "H" schedules are expanded in this

[1] Decision No. 74689 (August 12, 2014)

case to include rate schedules individually, along with additional details. This methodology takes into account the increases associated with the rate design changes, the proposed increase in base rates and updated fuel costs.

Sixth, I address the weather normalization and customer annualization adjustments. Both of these adjustments reflect test year billing determinants under normal weather and year-end customer levels, respectively. This adjustment does not reflect a planned reduction in usage recently announced by the Company's largest customer as of the date of this filing. Once more information becomes available, the Company will propose a post-test year adjustment to reflect any substantial changes. For the weather normalization adjustment, I am proposing to use a more refined method that produces forecasts that are more closely aligned with actual results (what I call the "Average Temperature" method). Regarding the customer annualization adjustment, the Company proposes to use the same method that has been approved by this Commission in prior electric rate cases. I also summarize the Company's proposed transmission expense adjustment, and the adjustments and additions regarding miscellaneous service charges.

Finally, I describe TEP's proposed modifications to the Demand Side Management Surcharge ("DSM"), Environmental Cost Adjustment ("ECA"), the Lost Fixed Cost Recovery mechanism ("LFCR") and a portion of the changes to the Purchased Power and Fuel Adjustment Clause ("PPFAC") to better reflect how the specific costs addressed in each adjustor are identified and recovered. Regarding the PPFAC, the Company is proposing that the PPFAC rate be calculated as a percentage of a customer's base fuel rate, rather than as a single per kilowatt hour (kWh) energy rate that is applied to all customers. This approach will more fairly align the changes in fuel costs with each rate classes' base fuel costs.

For the LFCR, the Company proposes to allow recovery of lost fixed costs attributable to generation (including fixed-must run) and the full recovery of lost demand revenues, in addition to other changes. Generation costs are significant, unavoidable and necessary. Because the calculation of demand-related losses specifically identifies the actual amount of offset to the customer's peak demand, only allowing 50% of lost demand revenues does not reflect the actual value of demand-related losses.

II. COST OF SERVICE ANALYSIS.

Q. What is the purpose of performing cost of service studies and how is it beneficial to customers?

A. The cost of service study is the core foundation in developing just and reasonable rates. Once the Company's revenue requirement is calculated, the next step is determining how and from whom it should be recovered.

A properly performed CCOSS analyzes all costs and services provided to each of the primary rate classes. The CCOSS also provides a guide as to how those costs should be recovered from each rate class. As I will discuss later in my testimony, there are multiple ways of determining how costs should be functionalized, classified and allocated. While each party representing a specific group of customers may have an opinion on how those costs should be split between the classes, TEP is focused on allocating the costs as fairly as possible. Fair cost allocation is based on the principle of cost causation. This principle has been referred to as the gold standard of cost of service. Equitably allocating costs between the classes protects all customer classes and creates rates that attempt to assign customers the actual cost of serving them. The Company's goal is to create fair and equitable rates for all customer classes under sound Cost-of-Service and Rate Design principles.

Q. Please discuss the concept of cost of service as a tool for ratemaking.

A. The process of developing rates relies on cost of service for establishing both the revenue level by class and the design of rates. By understanding how costs are caused and establishing rates to reflect cost causation, the important principle of matching costs with revenues under new rates will be satisfied. While the CCOSS is a great tool to use in this process, sometimes technology and available data can constrain the overall outcome of the CCOSS.

Q. How does technology and available data limit the usefulness of the CCOSS?

A. The CCOSS attempts to match costs with cost causation. However, it must be recognized that the best possible matching may be constrained by the ability to measure all of the needed elements of cost causation with the current meter and billing technologies. As technology advances in both the areas of cost causation and metering to track those costs, one must also recognize the temporary nature of that constraint. Thus, it is important to begin to modify rate designs so that there is a reasonable transition to new, more efficient rates that are enabled by new technology.

Q. What is the objective of the CCOSS?

A. Based on allocated costs, the goal is to confirm which present and proposed rates generate revenues that recover appropriate levels of costs per customer class. The term "cost" covers both expenses (including taxes) and the return on the Company's investment. The total cost to serve a particular class varies depending on the customers' individual and combined consumption characteristics, installed facilities, labor, and other capital needed to reliably and safely serve customers in the class.

If the proposed rates produce customer class revenues resulting in each class generating revenues sufficient to earn a return on plant that matches the overall return on invested

capital, "parity" has been reached. This is typically characterized by a "return index" (actual return/ required return) of one (100%) for each class. The CCOSS is designed to clearly present the costs and the allocation factors applied to the costs. The cost model also includes sections summarizing costs, a list of the allocation factors, and a revenue requirements summary. The "G" Schedules of the filing are assembled using the results of the CCOSS. Please refer to Schedule G-2 – Summary at Proposed Rates to see the results of the Company's CCOSS calculations.

Although existing circumstances may preclude reaching "parity", the goal should be to use the results of the CCOSS to minimize cross subsidies both between and within customer classes.

Q. Please summarize the types of CCOSS used in allocating revenue and designing electric rates.

A. Cost studies may be based on embedded costs or marginal cost. Embedded cost studies analyze the costs for a test year based on either the book value of accounting costs (a historical period), the estimated book value of costs for a forecasted test year or some combination of actual and forecast costs. The cost of service period is adjusted for known and measurable changes and is normalized and annualized. The cost of service used for the study is also used to determine the revenue requirement and is based on the 12-months ending June 30, 2015 for this filing.

Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions and classes and between customers within a class. In addition to providing information related to the allocation of revenue requirement changes among customers, the CCOSS provides valuable information for rate design. A fully unbundled CCOSS

provides the fully allocated costs of a detailed list of various services provided by the Company.

By contrast, marginal cost studies do not reflect actual costs but rely on estimates of the expected changes in cost associated with changes in service. Marginal cost studies are forward looking to the extent permitted by available data. Marginal cost studies are most useful for rate design when it is important to send appropriate price signals associated with demand and energy consumption by customers in a particular class. Marginal cost is also important for determining optimal seasons and time of use periods. In this case, TEP is relying on information from both the embedded and the marginal cost studies for its recommendations related to rate design.

Q. Have you prepared cost studies for this case?

A. Yes. The embedded cost study for the test year has been prepared under my supervision and can be found in Schedule G submitted as part of this filing. Also prepared under my supervision is an analysis of the marginal customer costs for residential and small general service customers to support improvements in the efficiency and tracking of costs for the historic two-part rate design consisting of basic service charges and volumetric charges.

Between the marginal cost study and the embedded cost study there is sufficient information to develop a just and reasonable rate design for customers in the classes where we currently bill only a basic service charge and an energy charge. Ultimately, the ideal rate design should include a combination of demand charges, a basic service charge and time differentiated energy charges for all. This will allow the Company to convey accurate price signals to customers about the cost of the individual services they purchase from TEP.

TEP is proposing the necessary steps to improve its price signals and to transition over time to more appropriate rate design. Thus, our proposal uses: (1) the results of the embedded cost study to provide important guidance for the class allocation of revenues; and (2) the embedded cost study and the marginal cost study to determine the level of specific charges that taken together create just and reasonable rates.

A. <u>Cost of Service and Economic Theory.</u>

Q. Please explain the importance of cost causation in developing a cost of service study.

A. Just and reasonable rates must avoid undue discrimination and must reflect the principle of "user pays," also known as "cost causation," or as I prefer to say, those who cause the costs should pay the costs. Undue discrimination occurs when customers pay significantly different amounts for the same service without good cause.

The development of cost-based rate structures permits regulatory review of the costs that are the same on average for customers in the class. I say "on average" because no two customers are exactly alike. Therefore, we determine costs and set cost-based rates for "typical" customers grouped by similar demand and usage patterns. For example, residential customers may have different service costs just based on the proximity to the distribution transformer. Typically, the customer on the same side of the street as the transformer will have a shorter service line than the customer across the street. As a result, the cost of service differs based on which side of the street the home is located.

In setting rates, we use the average cost of the two services. Once we determine the customer-related costs, those costs should be recovered in the basic service charge. If those costs are not recovered in the basic service charge, then they are recovered in the volumetric charges which results in the customers with higher than average energy

consumption subsidizing the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

I am not alone in expressing this view. For example, the Rocky Mountain Institute has published a report titled "RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE". That report, published in August 2014, recommends full unbundling for efficient integration of distributed resources that include not only DG but conservation and DSM as well. In the executive summary the report states "...bundled, volumetric block rates—provide little or no incentive for the deployment and operation of DERs (Distributed Energy Resources) at the times and places where they can create greatest overall benefit. The perpetuation of these pricing structures in the face of ongoing improvement in DER cost and performance and increased adoption of these technologies will result in *lost opportunities for cost reduction and inefficient utilization of assets on the part of both customers and utilities*." (Emphasis added.)

It is also important to know the marginal cost because the economic concept of "subsidy free rates" means that the rate must be above marginal cost but less than stand-alone costs. In order for rates to be efficient, the concept of customers being charged for the distinct services they use is important because different customers use different services. Further, the costs of those services may be different because of the different load characteristics of customers within the same class. Both cost allocation and rate design are critical in designing efficient rates.

Q. How have you approached the development of the cost studies?

A. A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system. In developing both the embedded cost study and the marginal customer cost study, I have relied on input from planning, engineering and operations within the Company.

Q. Please describe the nature of utility costs.

A. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs.[2] In addition, utility costs may be fixed or variable.[3] Finally, utility costs exhibit significant economies of scale.[4] These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies requires an understanding of the operating characteristics of the utility system. Further, as noted above, different cost studies provide different contributions to the development of economically efficient rates and the cost causation by customer class.

Utilities are unusual in the relationship between fixed and variable costs. The only variable costs for an electric utility are the costs of fuel, purchased power, fuel handling

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[2] Common costs occur when the fixed costs of providing service to one or more classes or the cost of providing multiple products to the same class use the same facilities and the use by one class precludes the use by another class. Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions. In either case, the allocation of such costs is arbitrary in a theoretical economic sense.

[3] Fixed costs do not change with the level of output, while variable costs change directly with the utility output. The vast majority of non-fuel related utility costs are fixed and do not vary with changes in load.

[4] Scale economies result in declining average cost as output increases and marginal costs are below average costs.

and some limited amount of variable operating and maintenance expense ("O&M"). All other costs are fixed. The fixed costs for TEP represent the sunk costs of the utility to produce and deliver electricity and provide other services to customers, such as taking energy from customers who self-generate in excess of their own needs and push that excess back onto the distribution system for delivery to other customers. The portion of fixed and variable costs of the total cost of service varies among the customer classes based on the types and quantity of the services used by the customer. Currently, the fixed component of TEP's residential rates (Basic Service Charge) only recovers approximately 17% of the average level of fixed costs approved in the Company's last rate case with the remaining fixed costs being recovered volumetrically through the delivery charge.

As a practical matter, failure to recover fixed costs in fixed charges results in unreasonable outcomes by creating subsidies both between and within the classes. It can also result in the utility recovering either more than or less than the authorized revenue requirement, based on whether consumption is higher or lower, respectively, than the levels used in the determination of base rates.

In today's market, traditional rate classes are no longer homogeneous. In fact the availability of self-generation (particularly solar distributed generation) has created a second class of customers within the typical residential service class. Some customers remain the traditional full requirements customer using all of the bundled services of the utility while a growing number of customers have become partial requirements customers who use the utility's services differently. Partial requirements customers require various utility services including standby service, supplemental service, delivery service for both in-bound and out-bound power flow, regulation services, power factor correction and balancing. For distribution services, the cost of serving these partial requirements customers is typically the same or higher than it was when the customer was a full

requirements customer.[5] However, the self-generating customer purchases far fewer kWh and thus avoids paying for fixed distribution costs when rates recover those costs in energy charges. The table below illustrates this problem. The table presents a comparison of two residential customers with identical energy usage and delivery requirements. The customers both use an average of 900 kWh per month. One customer is a full requirements customer taking service on Rate R-01. The other customer is a partial requirements customer and owns a photovoltaic ("PV") DG system that is sized to produce 100% of the energy the customer uses over a year. The partial requirements customer is on a net metering tariff that allows the banking and rollover of excess self-generated energy production.

Residential Customer Comparison	**R-01 Full Requirements Customer**	**R-01 DG Customer with Net Metering**
NCP kW Demand	6.3	6.3
Annual Billed kWh	10,800	32
CCOSS Customer Costs ($/customer/year)	$188.00	$188.00
Distribution Demand Cost ($/NCP kW/year)	$44.27	$44.27
Annual Customer & Distribution Costs	$466.19	$466.19
Annual Customer & Distribution Revenue	$437.09	$240.3

As this table illustrates, even though the partial requirements customer requires the same sized equipment and has the same capacity needs (e.g. on cloudy days or at night), they are paying only a little over half as much as the full requirements customer for the fixed costs of electric service. In reality, the partial requirements customer is also likely to require more services than the full requirements customer, even though their demands are the same.

[5] This is because the DG customer may require additional investments in the distribution system to provide frequency control and power factor correction, for example.

The Company is moving to a new rate design model that is designed to better recognize that the distribution system is a critical and regulated or monopoly component of the new market model. While distributed generation, in the form of PV solar, wind and combined heat and power ("CHP"), changes the amount of energy that must be produced by central generation, it continues to be dependent on the distribution system for many critical services.

Q. How is cost causation determined?

A. In many cases determining cost causation is as simple as asking the question of whether a particular cost changes when the service required by a customer changes. If a change in a customer's service causes a change in costs, then the particular service should be considered a cost causer. For example, if the number of kWh increases, does the cost of some input such as miles of conductor increase with more kWh? Since the miles of conductor do not change with kWh either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that the number of miles of conductor increases when new customers are added to the system, thus the customers are the cause of the cost. We also know that the length of conductor increases with the growth of the peak load on the conductor which may require paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductor are customers and a measure of non-coincident peak demand. Following this logical process allows one to determine cost causation for each element of the system.

Fundamentally, performing cost of service studies is comprised of applying experience and science. The science of the process involves calculations consistent with the methods outlined in the National Association of Regulatory Utility Commissioners Electric Utility

Cost Allocation Manual ("NARUC Manual"). The art of applying experience involves the subjective application of certain methods, in conjunction with consideration of policy objectives, regulatory case law, emerging issues, and other factors, within the framework of the regulatory process. Every utility system is different and those differences impact the choices that the cost analyst makes based on the relevant cost causation factors for each utility system. The art of the cost study is having an understanding of how the unique characteristics of the utility should be combined with the various scientific methodologies.

Q. How do you decide what type of cost you are analyzing?

A. There are three fundamental cost classifications that are the basis for cost causation: customers; demand; and energy. Essentially, all costs incurred by the utility are directly or in some cases indirectly related to one of these three classifications. That is, a utility incurs costs based on: (1) the number, size, geographic location and type of customers; (2) a combination of several measures of customer demand; or (3) a measure of the energy used by customers. Within these three cost classifications there may be different measures of the factor based on how costs are incurred when allocation factors are developed.

The NARUC Manual identifies three fundamental methods for allocation of demand related costs: Coincident Peak ("CP") methods, Non-Coincident Peak ("NCP") methods and Average and Excess Demand ("AED") methods. Within each of these categories, there are numerous specific formulations of the methods. Further, to reflect the cost of an electric system, a complete cost of service study requires application of more than one demand category of these allocation methods. For example, class non-coincident peaks drive the allocation of part of the distribution system capacity while it is some combination of coincident peaks and demand and energy methods that drive the allocation for generation. Within each of these fundamental allocation methods, there may be multiple specific methods. CP allocation category options include a single CP, 4 CP, 12 CP,

winter/summer CP and so forth. In addition to the AED allocation method, there are a number of methods that consider both demand and energy such as peak and average, peaker methods and so forth. These methods are all described in the NARUC Manual.

In any event, the choice of allocation methods relies on the concept of cost causation to choose the most appropriate method that best reflects those costs based on the particular utility's system. NCP methods may use a variety of peaks other than the actual system peak based on the peaks of individual service classifications or individual customers. Cost causation requires the determination of the cost to serve each class of customers in a way that recognizes apparent cost responsibility and reflects the engineering and operating characteristics of the utility system. It is not unusual that a cost study includes all of the methods for allocating demand and more than one of the variants of these methods.

Q. Please explain the classification and allocation of distribution costs.

A. There is an underlying logic to the choice of the most appropriate demand allocation methodology. The system distribution plant consists of different facilities that have different cost causation factors. The reason for this is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility cost is the direct result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest transformers cost much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since

every customer requires transformer capacity.[6] For transformers larger than the minimum size, the remainder of transformer cost is related to demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer. Thus, transformer demand is related to the individual customer NCP. The NCP for the system based on the sum of individual customers is much higher than either the system coincident peak or the sum of the class NCPs. For facilities located close to the customer, such as transformers, secondary conductor, and secondary poles and even single phase primary conductor, both a customer component and the individual NCP allocation factor is the most appropriate. As the cost becomes more remote from the customer, it is the class NCP that drives the costs. This applies to the demand portion of primary poles and primary conductor. The substation related investment is based on the class NCP allocation factor alone. In fact, any number of substations peak at different times and even different seasons from the coincident peak demand of the utility.

Q. Have you considered the customer component in the CCOSS you have developed for the Company in this rate case?

A. Yes. The allocation of certain costs to a mix of "customer" and "demand" is provided in Schedule G, sheet G-7 Allocations.

[6] For larger customers, the customer may provide its own transformers or even its own substation in the case of some very large customers. These distinctions are typically reflected either as credits in rates or separate rate schedules for different service classes defined based on use of distribution facilities.

Q. Are all customers allocated some level of distribution costs?

A. Yes, but not always at the same level. Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of certain portions of the distribution system at all. As a result, only limited amounts of distribution costs are allocated to customers taking service at 138 kV. Metering related costs, some level of intangible and general plant and a portion of administrative and general ("A&G") costs have been included in the allocation to this class. Where customers own their own substation and connect directly to the transmission system, the customer causes no specific plant related distribution costs to the utility. These customers are typically served either through special contracts or under a transmission voltage service rate schedule. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. In that case, the customer may require special rate provisions such as a facilities charge or power factor adjustment to pay for the extra investment. When customers share common load characteristics that are substantially more or less than a comparable standard customer, they may warrant a separate class of service. This is particularly important to recognize for partial requirements customers who would typically require their own class of service because of their unique load characteristics.

For distribution plant costs found in FERC Account Nos. 364 - 374 either all or a portion of the costs are customer related because they are caused by customers. For Account No.

369 - Services, each customer has a service designed to meet that customer's own load characteristics. Services are dedicated to a customer based on their load and each customer causes the cost of its service even if the customer never consumes any energy beyond that required for a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory basic service charge, the result is not just and reasonable and causes undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system. More importantly, there are demand related costs associated with the distribution system that must also be recovered. Partial requirements customers who use little or no net energy must still have a distribution system designed to meet the maximum non-coincident peak of the customer. TEP must have an opportunity to recover these costs as well.

Q. How is the appropriate level of meter and metering related costs determined by customer class?

A. Electricity will not flow into a premise (at least not legally, unless it is an un-metered lighting customer) without an electric meter (Account No. 370). Meters are virtually the same for all small customers. However as the size of the customer increases, the meter installation becomes increasingly complex and the cost of meter sets increases. In addition, Account Nos. 371 – 373 (investments on the customer's premise) represents facilities that are also customer related. In the case of these facilities, the customers who request the extra service provided by these facilities typically pay for these directly as in the case of Account No. 373 related to lighting. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system (or receive service) without a minimum level of distribution services provided through the assets in Account Nos. 364 - 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system and to meet the maximum demand of those

customers. All existing premises were at one time new customers for whom the system must have been extended. Further, the Company must continually replace aging infrastructure to continue to serve all customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The minimum system concept assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs. The current costs for new, minimum sized facilities are a fundamental component for estimating the marginal customer costs for TEP. The demand component of these costs also needs to be recovered to compensate for standby and supplemental services as well as the other services typically provided to support a DG installation.

Q. Are there other costs that are customer related and should be allocated to the basic service charge calculation?

A. Yes. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer-related costs as well. In addition, where all of an account is allocated as customer-related, all of the O&M should also be allocated to customer costs. Second, customer service related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities, the meter shop, stores and tools and equipment. Fourth, a portion of administrative and general expenses should be included in the customer costs as well. Inclusion of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items

related directly to employee costs. These costs are also a proxy for the marginal customer cost study.

Q. Please discuss the classification and allocation of distribution plant.

A. As noted above, distribution plant is classified as demand, demand and customer, or just customer depending on the costs. Each component of the distribution system requires a different allocation factor based on the classification of the costs and the role that customer diversity plays in causing the costs. For plant functionalized as distribution plant and found in accounts related to facilities associated with distribution substations (Account Nos. 360-363), the plant is classified as demand and is allocated on the class NCP. Substations reflect the diversity of the customers served out of a particular substation. Typically, substations have different mixes of customer class and loads. As a result, substations often peak at times different from the system peak loads. Some substations may even have peak loads in a different season of the year than the system. The use of the sum of the class NCPs accounts for the differences that occur in the capacity demand on substations. Diversity of load on the distribution system is greatest at the substation level where multiple feeders serve a variety of customers and loads.

For distribution facilities in the accounts related to the power lines and transformers (Account Nos. 364-368) where power is delivered to the interconnection point with the customer, the costs are classified as both customer and demand. While there are several methods to classify these costs between customer and demand, the minimum system approach is the most consistent with cost causation because it represents the actual cost of connecting a customer to the system to serve the minimum load that meets the parameters of the approved line extension policy. Any investment, greater than the minimum system, must be related to the customers' maximum demands on that portion of the system. Thus, in addition to the customer allocation, the demand allocation is based on the sum of the

customers NCPs for each class of service. For the remainder of the distribution accounts (Account Nos. 369-373), the costs are classified as customer and are allocated on a customer basis with as much direct assignment of costs as possible. The final distribution account (Account No. 374) is related to amortization of polychlorinated biphenyl related costs and is allocated based on the transformer investment.

Q. Is there a listing of allocation factors?

A. Yes. Allocation factors are listed in Schedule G-7.

Q. During the rate design process, did you achieve parity as it relates to each classes contribution to the return on plant?

A. No. The Company strives to achieve parity where possible, but due to the principle of gradualism, we made some reasonable adjustments. The impact on customers must be compared to the benefits of moving to fully cost-based rates. This approach moderates what would have been even larger variations in the percentage rate changes some classes would have received. In other words, we balanced the need to move each class towards rates that are more reflective of cost of service while recognizing that such a move must be tempered with other factors like gradualism. Some classes will be affected more than others because their below cost of service rates have been subsidized by other customers for many years. The Company is attempting to move in the general direction of parity between classes, and send customers more accurate price signals, but to truly achieve parity will likely take a few more rate cases.

To better understand how the return on plant varies by rate class based on the different assumptions, the table below reflects the by-class return on plant at the Company's proposed rates under the demand allocation method used in the last rate request and the method the Company is proposing in this rate case. Historically, the Company has used

the Peaks and Average method, but in order to address an argument that the Peaks and Average method may have the effect of doubling some portion of demand-related costs that are allocated to certain rate classes, the Company has chosen to move to the Average and Excess method. This is the method used by APS and is a commonly accepted methodology used throughout the utility industry.

CCOSS COMPARISON OF DEMAND ALLOCATIONS

	RESIDENTIAL SERVICE	SMALL/MED GENERAL SERVICE	LARGE GENERAL SERVICE
Current Method: Average & Excess & 4CP			
Demand	1,170,148	510,535	271,781
RETURN AT PRESENT RATES	-1.60%	19.35%	4.61%
RETURN AT PROPOSED RATES	**$17,239,214**	**$78,421,423**	**$52,019,773**
RETURN ON RATE BASE	**1.51%**	**16.13%**	**21.60%**
Method Last Case: Peaks & Average & 4CP			
Demand	1,036,724	482,855	318,777
RETURN AT PROPOSED RATES	**$38,377,205**	**$82,809,951**	**$44,582,737**
RETURN ON RATE BASE	**3.60%**	**17.62%**	**16.66%**

B. Marginal Cost of Service Study.

Q. Please explain why a marginal cost study is of value in this case.

A. There are several reasons why knowing the marginal cost is valuable in designing rates. First, economics tells us that prices set on marginal cost leads to the efficient use of scarce resources. Customers cannot make efficient decisions about how to spend their energy dollars, including capital investment, unless they know how costs will change at the margin. For example, under cost-based rates, if a DG customer and a full requirements customer use exactly the same average distribution system components, the rates charged

to both customers for those services should be the same. If the DG customer uses more of some service, such as voltage regulation, because of the intermittent nature of the solar PV system, that extra cost should be borne by the DG customer. If rates do not recover the same or even more costs from the DG customer in this instance, the allocation of energy dollars is economically inefficient because of the resultant subsidy.

The second reason for understanding marginal costs is that if a customer pays less than marginal cost for the service, other customers would be better off if that customer was not served by TEP. This situation is analogous to an extension policy where if the revenues are inadequate to support the investment, the customer makes a contribution to defray the excess costs so that other customers do not have their rates increased to provide a connection subsidy at the margin.

Third, marginal cost provides a guide to rate design. Essentially, the price of any unbundled service should not be less than marginal cost. In the case of the basic service charge, the charge is really more appropriately classified as an access charge. That is, it represents the cost of having access to the unbundled distribution services of the utility. Therefore, the marginal cost study identifies what the floor is for establishing a basic service charge, where the embedded cost study indicates in total the revenue requirement to be recovered from the combination of all charges. This establishes a minimum basic service charge for the class.

Q. Please describe the marginal customer cost study.

A. Studies used to calculate marginal costs are common in rate case filings and use relatively consistent methodologies. Marginal cost studies focus on the change in costs associated with a small change in the number of customers added to the system or the cost to replace the current customer-related infrastructure to continue service to an existing customer.

Marginal costs are forward looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement, particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the system are lumpy and as a result, utilities' optimal additions often include more capacity than the marginal change in customer count.

Q. What are the steps involved in estimating marginal cost?

A. To estimate marginal cost, the first step requires determining the change in cost associated with the addition of a new customer on average. I say on average because there are two different types of customers that may be added to the system. The first type of customer is added at a point on the existing system and thus requires a smaller investment than a customer that requires a larger investment such as a line extension. The second type of customer is added at the periphery of the system and requires extra investment to connect the customer to the distribution system. The marginal cost study takes this into account by weighting the proportion of customers that are in each category.

Electric distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into

consideration the density of customers in a particular location and the expected loads of those customers. For example, an area with all-electric homes may have different design standards than an area where the homes are not electrically heated. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served ultimately, not specifically on the number of customers or their actual loads at any given moment. The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve local loads and include: substations, feeders, transformers, service drops and meters. Feeders may be primary or secondary lines depending on the location of the customer and the design of the system. The customer component of these systems is related to the smallest size of the equipment that is installed to serve customers. If larger equipment, such as that required for all electric homes, is installed the extra costs are demand related. The economies of scale in the distribution system mean that the demand-related cost is much less significant than the customer component.

Q. Have you provided the marginal customer cost study results?

A. Yes. The results of the study are attached as **Exhibit CAJ-1** and consist of three schedules. Schedule 1 is a summary of all of the components, the costs and provides the marginal customer cost for residential and small general service customers. Schedule 2 provides the minimum system investment for each component of the customer marginal cost along with the levelized carrying charge rate for each component to produce the revenue requirement for the component. Schedule 3 provides the customer-related expenses based on the embedded cost study that are customer related.

Q. Have you identified the minimum size components used by TEP in the delivery system?

A. Yes. We have worked with the Company's distribution engineering and operations groups to determine the smallest standard size of facilities used and with the accounting function to determine the fully loaded installed costs of these components. Schedule 2 in **Exhibit CAJ-1** provides the cost of the minimum system components. In addition, the schedule provides the economic carrying charge rate and the appropriate weighting for customers requiring a line extension. This schedule produces the marginal revenue requirement for customer-related capital expenditures. The economic carrying charge rate uses the Company's capital structure and the marginal cost of the components of that structure. The forward looking nature of a marginal cost study requires that the capital cost be estimated on an incremental basis, not on embedded costs.

Q. Have you identified the customer related expenses?

A. Yes. The customer related expenses may be found on Schedule 3 in **Exhibit CAJ-1.** These expenses were based on embedded costs as a proxy for long-run marginal costs. In the short-run these costs would be zero because adding one customer does not change most of these costs. However, at some level these costs would increase by an amount related to the average cost when a minimum number of customers have been added. This approach provides a reasonable proxy for the O&M related costs.

Q. Please summarize the results of the customer costs on an embedded and a marginal cost basis.

A. The results are summarized in the table below.

Table 1

Cost Study	Residential	Small General Service
Marginal Customer Cost	$29.49	$219.60
Embedded Customer Cost	$15.67	$45.55

Q. Why are marginal customer costs so much higher than embedded customer costs?

A. There are several reasons marginal costs are much higher than embedded costs. First, as part of the Company's efforts to improve service reliability and have the capability to refine its rates to modern unbundled rate design, the costs reflect a significant change in metering technology. These meters are more costly than the traditional watt hour meters used since the 19th century. Second, the impact of inflation on certain portions of the distribution assets has been significant. For example, since 2005 the cost of electric transformers has increased by over 42% based on the Handy Whitman Index. This means that the depreciated original cost for these assets is far below the replacement cost for these assets. Third, the pattern of infrastructure replacement differs from the installation of all new infrastructures. This timing difference results from the different useful lives of the original infrastructure installed to serve customers. At any point, the average age of assets and the pattern of cost recovery is significantly different resulting in higher marginal costs.

Q. Please explain how the embedded and marginal cost of service studies provide the necessary support for the proposed basic service charge levels.

A. The embedded cost of service study guides the allocation of revenues among the classes of service. Specifically, that study, which includes use of the minimum distribution system approach, clearly identifies the embedded levels of distribution, customer related, and other costs by class of service. In order to fully evaluate the appropriate level of basic service charge, a marginal cost of service is required to support and reflect a valid

price signal related to connecting customers. To the extent that the basic service charge is set below the marginal cost level existing customers will be subsidizing the costs of connecting new customers. Together, the embedded and marginal cost studies provide the Commission with the full picture as to how total revenues should be allocated across classes; and in turn, how customer costs and the cost of connecting a customer should be set to send correct price signals to customers and to encourage economic use of the system.

III. RATE DESIGN.

A. Overall Objectives of Updated Rate Design.

Q. What are the Company's objectives in rate design?

A. The Company's primary objective is to modify existing rates to recover costs in a more equitable manner from all similarly situated customers. The Company is proposing to do this by shifting more of the fixed costs into fixed rate components for the more than 95% of the customers who are on a two-part rate and to create rate classes that contain a more appropriate grouping of customers.

To move toward this objective the Company must continually evaluate and adjust rates to evolve with changing cost structures, customer usage patterns, market changes and technology changes. An important first step is to move toward more equitable rate design that will recover more of the system fixed costs, in rate components that better reflect system usage.

Q. Are there other significant rate changes that need to be made to move toward more equitable structures?

A. Yes. The Company is proposing rate class changes to more appropriately group customers by the way these customer groups use the system, including the elimination of Rate LLP-14. A new MGS class will be established that will contain both a minimum and a maximum kW level. This will allow the largest Small General Service ("SGS") customers to move to a more similarly sized, homogeneous rate class that will include a demand charge which will help recover costs in a manner more reflective of the way the costs are incurred. Additionally, the Company is proposing to establish a new 138 kV rate that will be offered to only those customers with the ability to take service at this transmission level voltage or greater. This 138 kV service will only be available for consumption at the meter capable of receiving service at this transmission level voltage, or greater. The Company is proposing the elimination of two rate tiers in the Residential rate class and the addition of a rate tier to each of the rate classes' comparable TOU rates to prevent higher energy usage customers from taking advantage of the TOU rate without having to modify usage habits.

Q. Are there other reasons justifying the need for TEP to update and modernize its rate schedules?

A. Yes. In addition to the reasons outlined above, TEP's proposed rate design has two secondary objectives: (1) to initiate movement to updated industry rate design standards that are more aligned with the Company's need for fixed cost recovery; and (2) to reduce existing cross-subsidies within and between customer classes. To meet these objectives, the Company proposes: a somewhat lower percentage rate increase for classes presently paying more than the system average return on rate base based on the results of the CCOSS; and a higher percentage rate increase for classes presently paying less than the system average return on rate base, where the resulting bill impact is reasonable and

consistent with the gradualism principle. **Exhibit CAJ-2**, which I discuss in more detail below, sets forth average annual bill impacts for each of the rate classes based on the Company's proposed rates.

Q. What other considerations were made in developing the Company's rate design proposals?

A. As we analyzed each of the proposed rate design changes and evaluated their potential impacts on customers, we also had to develop a full understanding of how these changes would affect revenues. Our considerations focused on billing determinants,[7] ratchets,[8] and consistency. To best determine the true impact on the customer and the Company revenues, we went to great lengths to determine the appropriate levels of billing determinants. It was essential that we had a complete understanding of the billing determinants as we modified provisions within the tariffs. For the Demand Charge in the new MGS class, we evaluated how the billing determinant changes will impact customers' bills and the Company's revenues as the 75% ratchet is applied to a group of customers that has not historically been billed based on a Demand Charge. Applying a Demand Charge will impact various customers more than others. The Company has attempted to identify groups of these migrating customers that will be falling into different levels of impact. These different levels of impact will be grouped into customers that we anticipate will experience an overall, annual increase at or below the average increase for the class, a group with a moderately larger increase than the class average

[7] Billing determinants are number of units on which each of the billing components would apply to generate the Company's Revenue Requirement. By class, this would include the number of bills on which the basic service charge applies, the number of total demand units on which the Demand Charges apply and the number of kWh on which the volumetric charges apply.

[8] A ratchet is a billing provision under which the Demand Charge for each month is based on the highest billed demand over a period of time in the previous year. This mechanism minimizes risk of not recovering fixed costs and properly compensates for the year-round expenses incurred to provide service to a customer. It is also consistent with the fact that the distribution system demand costs are incurred based on the maximum demand of the customer whenever it occurs.

and a group with an increase of a magnitude that will require special consideration to help mitigate if possible. Extra consideration must be made to inform and work with these customers. Numerous methods of communications have been considered, depending on the level of impact and, where warranted, methods of offering temporary billing considerations have been evaluated to allow a customer some time to acclimate to the new rate design.[9] The Company is requesting that as efforts are made to mitigate the bill impact for these customers, a temporary provision be discussed and arranged that will allow the Company to maintain revenue neutrality for the class.

The other demand-related change the Company is proposing in this case is for the current demand charge method used in the current Rate LPS-90 to be applied to the other large customer TOU rate classes as well (the new MGS TOU rate and the current Large General Service ("LGS") TOU rate, Rate LGS-85). Therefore the Company is proposing to use the same method of calculating on-peak and off-peak demand for all three large customer rate classes and the 138 kV rate class. This maintains the same design relating to the demand charges approved for Rate LPS-90 in TEP's last rate case for all other large customer TOU rate classes with a demand rate. This design promotes load shifts from on-peak periods to off-peak periods.

Q. What must be considered with respect to whether the ratchet and billing determinants result in just and reasonable rates?

A. First, in developing these proposed modifications, a thorough analysis must be performed to best ensure that the impacts on the customer are understood and the proposals are fair

[9] Since these customers are moving from a non-demand based rate to a demand based rate, low load factor customers, seasonal customers, cyclical use customers, etc. may see unusually high bill impacts. An attempt will be made to mitigate any disproportionally large impacts. Prior to the hearing the Company would like to discuss options with the other parties to arrive at a way to create a revenue neutral way to allow this mitigation of impact to the 50 or so customers the Company believes will be most affected.

and equitable. Second, in the event even one of the design parameters is changed during the rate case process, the billing determinants and ratchets must be re-evaluated to assure the bill impact is acceptable and revenues generated are as expected.

If any change is made to a rate design component, an equivalent review and appropriate change in billing determinants must be made to the revenue proof to assure the revenue proof reflects the appropriate recovery of revenues.

B. <u>Specific Rate Design Changes.</u>

Q. Please provide an overview of the changes that the Company is proposing that are not class specific before moving to the individual rate classes.

A. First, the Company is proposing to increase all monthly basic service charges in a manner consistent with the results of the CCOSS and equitable fixed cost recovery. TEP proposes an increase in monthly basic service charges to levels that better match, but are not equivalent to, the customer-related costs and the minimum cost to serve the customer as indicated by the CCOSS and the marginal cost study which was used as a guide to determine what the minimum cost to serve a customer should be. The majority of TEP's non-fuel costs are fixed in nature because the Company's requirement to ensure that service is available (including having the distribution infrastructure in place) does not change if a customer decides not to use energy on a given day.

Second, the Company is proposing to change the PPFAC charge to a percentage-based rate instead of a per-kWh rate and that it be recalculated monthly based on a 12-month rolling average cost of purchased power and fuel as discussed in more detail in the direct testimony of the Company's witness Michael Sheehan. The Company is also proposing

to change the residential DSM and ECA charges to percentage based adjustments. These changes will be discussed more thoroughly later in my testimony.

Third, for TOU customers, the Company is proposing to add a tier to the rates where the non-TOU option contains a tier. In TEP's last rate case, the Company proposed to eliminate the tiers for TOU customers in the hope that the simplified rate would be more appealing to the customers. This inadvertently created a perverse situation where the largest usage customers could benefit from lower average rates and as a result, a lower bill without changing their consumption to off-peak from on-peak times. This unintended consequence can be rectified by adding a tier back to the appropriate TOU rates.

Fourth, for most non-interruptible classes with a Demand Charge, the Company proposes to establish minimum and/or maximum demand amounts (billing demand levels) in order for a customer to become and remain eligible in the individual classes. This should provide for better parity within the classes and thus less intra-class inequity which will make it easier for customers to stay on a particular rate.

Fifth, the Company's current SGS and Large Power Service ("LPS") rates will be redesigned. The Company is proposing to create a new MGS rate that will contain approximately 3,995 former SGS customers and 93 former Large General Service ("LGS") customers, but will be limited to only those customers who the Company has estimated, based on test year data, to use a combined total of 24,000 kWh or more in any two consecutive months or who the Company has calculated will have a minimum demand of greater than 20 kW. Those migrating customers will also be tested to determine if their demand will exceed 250 kW in any month. If so, they will be moved to either the LGS or LGS-TOU rate, as appropriate. Other than the minimum and maximum demand amounts, the design of the new MGS rates (standard and TOU) will be generally

the same as the current LGS rates (e.g. 75% ratchet, winter/summer differentiated rates and a single tier rate). The new LGS rate will not undergo a rate design change (e.g. the 75% ratchet will remain), however the billing determinants used to calculate the rates will be recalculated to blend in any migrating customers and the TOU demand calculation will be modeled after the existing Rate LPS-90 method.

The current LPS-TOU customer class (Rate LPS-90) will reflect the current rate design but will see former mining customers blended into the class for purposes of developing the rate. As of the filing of this rate case there is only one customer on the non-TOU LPS rate (Rate LLP-14) and that customer would likely save money if they move to Rate LPS-90. Therefore the Company is eliminating Rate LLP-14 as an option and moving the customer to Rate LPS-90. This is not only beneficial to the impacted customer it is consistent with our general theme of keeping customers on the most cost effective rate classes where possible. Additionally, customers of this size will be more attentive to operating in the most efficient manner if they are on a TOU rate.

Lastly, a 138 kV rate will be established for any customer taking service at a dedicated service point at 138 kV or greater. The general rate design will be similar to the current Rate LPS-90 with the exception that a lower level of losses will be built into the fuel rates because service is being received at the higher transmission level voltage and a portion of the distribution-related costs will be excluded from this rate. All customer related costs and a certain level of distribution level costs will be included in the rate, but some distribution plant will be removed since it is not technically utilized to serve this class. Other system related distribution costs will continue to be assessed to this class since it is still providing benefits to them. This would include A&G, common plant, taxes, overhead costs, etc.

For these firm non-TOU classes the billed demand amount will continue to be based on the greater of: (1) the greatest measured 15-minute interval demand read of the meter during all hours of the billing period; (2) 75% of the greatest demand used for billing purposes in the preceding 11 months; or (3) the contract capacity or the specified minimum demand amount, whichever is greater.

For the firm TOU classes, the billed demand will be based on the method currently in place for Rate LPS –90.

Q. Does the existing rate design, which recovers a significant portion of the fixed costs through volumetric energy charges for most customers, create problems other than revenue instability?

A. Yes. First, the collection of significant fixed costs through energy charges places a disproportionate burden on the customers who are typically using the system the most efficiently. Even though a higher load factor customer is using the system more efficiently (and therefore more cost effectively) than a low load factor customer, having a larger proportion of the fixed costs in the energy rate will result in that higher load factor customer paying a disproportionate amount of the system cost. Shifting revenue collection away from volumetric energy charges reduces the cross-subsidization that occurs when usage within customer classes varies significantly. It also reduces a rate design that promotes the inefficient use of the system.

Second, the existing rate design creates the wrong price signals. Rate design that creates an over-dependence on fixed cost recovery through volumetric energy charges creates an economic disincentive for the Company to promote conservation, EE, and DG. If non-fuel rates are collected primarily through volumetric charges and the recovery of costs is dependent on usage, the associated reduction in sales significantly erodes TEP's ability to

earn its Commission-authorized rate of return. This is true even with the LFCR mechanism, as currently designed, since 50% of any demand charge reductions and the entire generation component of retail rates is not currently included in the LFCR.

Q. Can this disparity be resolved solely through modification of the monthly basic service charges?

A. Only partially. The basic customer-related charges are a good starting point to identify what should be included in the monthly basic service charge for each class, but they do not tell the whole story. Historically, basic service charges are limited to metering, meter-reading, service (service drop) to the specific customer, and customer service and billing. While these costs should be included in the basic service charge and may be used as the guide to what the basic service charge should be for classes with Demand Charges, they are not sufficient for classes without a Demand Charge.

Q. Why is it appropriate for a portion of the demand-related costs to be included in monthly basic service charges for classes with rates that do not include a Demand Charge?

A. As discussed earlier in my testimony, the minimum cost of serving a customer includes more than what has historically been seen as customer-related charges. Without some level of demand-related cost being included in the basic service charge for classes without a Demand Charge, a disproportionate amount of the Company's fixed costs must be recovered in volumetric energy charges. Consequently, if customer energy usage falls, the Company will not have a reasonable opportunity to earn its Commission-authorized rate of return. Also, since the current LFCR rate excludes the generation component of retail rates, this will only be exacerbated as the amount of sales erosion from increased levels of EE and DG continues. Modifying the rates to include a higher proportion of fixed costs in the monthly basic service charges will help send customers

the right price signals and provide additional support for the Company's efforts to promote EE and DG. Specifically, because the residential and small general service classes currently do not have a Demand Charge, the cost of at least some of the fixed cost items required to serve a customer (such as transformers and distribution conductors) should be included in the monthly basic service charge. It was even acknowledged in the Commission's decoupling workshops that increased fixed charges would help minimize the revenues lost and ultimately recoverable in any decoupling adjustment (including a partial decoupler like the Company's LFCR mechanism.)

Q. Why does TEP prefer increasing the monthly basic service charges over further increasing the energy (per kWh) charges to recover fixed costs?

A. For the smaller rate classes, TEP currently collects the majority of its fixed costs through a volumetric energy charge, which is a conceptually flawed rate design and is made worse by the inverted nature of the charges that cause larger customers to pay well above their actual costs and well above the costs actually saved from conservation. This is because the bulk of a utility's costs are fixed and do not vary with the quantity of energy the customer uses on a given day. The Company is in the business of providing safe and reliable energy service. This means that facilities and personnel must be in place to ensure that customer demand is met – 365 days a year, no matter where or when the service is requested in the Company's service territory. In short, the Company earns a regulated rate of return on the infrastructure necessary to provide electrical service – on demand - to its customers. The obligation to provide safe, adequate, and reliable service does not change, regardless of whether or how much energy TEP's customers consume. This is why the majority of TEP's costs are fixed.

Periodic variation in energy consumption has limited impact on the true, non-fuel cost of serving customers. Most non-fuel costs are fixed and will ultimately produce a mismatch

between costs and revenues when a substantial portion of the revenues are recovered through weather-sensitive sales. Increasing basic service charges helps to address this disparity. When basic service charges are increased, energy charges are decreased (holding revenue requirement and other factors constant). Fixed basic service charge revenue stays relatively constant within a given month – despite weather variations, conservation efforts or (in the short run) economic activity. Consequently, basic service charges provide a relatively stable and predictable source for funding fixed costs, which constitute the bulk of a utility's non-fuel revenue requirement.

Q. Will the Company's proposed rate designs guarantee it the ability to earn its authorized rate-of-return?

A. Absolutely not. The Company's rate design hardly guarantees achieving its Commission-authorized rate-of-return ("ROR"). For the majority of TEP's customers, a significant percentage of non-fuel revenue recovery will still be collected through the energy charges (volumetric or per kWh). For example, TEP's residential class (which is responsible for approximately 46% of the Company's non-fuel revenue) is currently collecting approximately 83% of the class' non-fuel revenue through volumetric energy charges. This is similar for the general service class as well, and the general service class accounts for another 30% of the Company's non-fuel revenues. This large allocation of fixed cost to a volumetric energy charge potentially causes large swings in the amount of revenue collected to provide the Company an opportunity to earn its authorized ROR. Warmer than normal summer weather could result in over-recovery and cool summer weather will result in under-recovery of non-fuel revenues. Of course, any conservation effort or decreased use per customer will, by design, result in under earnings for the utility. Further, even with a three-year rate-case cycle, the costs of providing service, including O&M costs, material costs, and plant investments have consistently increased. These factors work against the Company's ability to earn its authorized ROR.

1. **Residential Rates.**

a. **Monthly Charge.**

Q. How do TEP's current residential monthly basic service charges compare to other Arizona electric utilities?

A. The Company's residential basic service charge covers a smaller portion of fixed costs than the residential basic service charges of other electric utilities in Arizona. TEP's residential basic service charge is only $10.00 per month (as low as $6.90 if currently on a Lifeline rate). In contrast, APS, Trico Electric Cooperative, Inc. and Salt River Project ("SRP") have basic service charges ranging from $15.00 to $20.00 per month, with TOU basic service charges in the $18.00 to $36.00 per month range. APS and SRP also have a Demand Charge that applies in addition to the basic service charge in one of its residential rate offerings. Considering that all electric utilities incur substantial fixed costs to serve residential customers, and that those fixed costs typically exceed the higher basic service charges approved for those utilities, TEP's current monthly service charge should be increased. While it is imperative to start addressing the issue of moving basic service charges towards reflecting actual fixed costs incurred, the Company realizes the difference cannot be fully addressed in a single rate case. Therefore, TEP is proposing an increase in the monthly basic service charge that makes a step in the right direction, but does not necessarily fully address the issue.

Q. With that background in mind, what increase is TEP proposing to the residential monthly basic service charge?

A. In an effort to move towards more appropriate monthly basic service charges for the residential rate classes, TEP proposes to increase residential basic service charges to $20.00 per month for both the standard and TOU residential customers with some

Lifeline customers paying even less when new rates are implemented. The proposed $20.00 basic service charge is still only approximately 21% of the $93.61 of fixed cost per residential customer quantified in the CCOSS (which is the combined customer service and demand related charges identified by the CCOSS for the residential customer) and is still below monthly basic service charges that this Commission has previously approved for other electric utilities.

Q. Will the increases in the monthly basic service charges also smooth out the amount of revenues that will be recovered through the Company's proposed LFCR mechanism?

A. Yes. Besides reflecting sound rate design principles, increasing these basic service charges will also help to mitigate the amount of lost revenues to be recovered in the LFCR. This is because as the fixed charges are increased, the volumetric charges are proportionally decreased for each rate class. Further, because the energy rate is lower, the total lost margin will be smaller for each kWh lost as the result of Commission approved EE and DG programs.

b. <u>Volumetric Rate.</u>

Q. What volumetric rate is TEP proposing for the residential rate classes?

A. Schedule H-3 shows the various rates and rate components for each of the Company's proposed rates. For the Residential Rate R-01 rate class, TEP proposes an average overall volumetric rate of $0.0688 per kWh (exclusive of purchased power and fuel costs), resulting in a $0.0048 per kWh increase on the average volumetric rate for the Rate R-01 rate. This rate is identified as the "Delivery Services-Energy" charge on the tariffs and is designed to recover the portion of fixed costs not covered by the monthly basic service charge.

Q. Describe the change for Rate R-01.

A. For Rate R-01, which is the residential rate for nearly 80% of our total customers, the Company is proposing only one substantial rate design change other than the increase to the basic service charge. The Company is proposing to eliminate the third and fourth tier in the residential rate class. It adds no cost-based value to the rate class other than exacerbating the issues of fixed cost being inequitably recovered from the higher usage customers. As we move to more cost-based rates, inverted block rates make less sense. As consumption increases, the cost per kWh actually decreases. Therefore, eliminating the upper rate tiers results in a more cost-based rate design. The Company would like to maintain only two rate tiers for the residential classes. However, there is no cost justification for inverted rates and certainly no cost basis for too many tiers in TOU rates. Thus, the tier proposal is an interim step to ultimately eliminate the tiers for more efficient rates.

Q. Describe the changes to the residential TOU rates.

A. Except for the change in the basic service charge described above, the only substantial change that the Company is proposing to make to the residential TOU rates is to add back tiers that align with what is currently in place for the Residential Non-TOU rate and as described earlier in my testimony.

2. <u>Non-Residential Rates.</u>

Q. Describe the changes the Company is proposing for the general service customers and the large power service customers.

A. Much like what the Company is proposing for the residential customers, the changes for general service and large power service customers are designed to more appropriately recover fixed costs in the fixed portion of rates. Basic service charges for the non-

residential classes also need to be increased to amounts closer to levels indicated by the CCOSS. The other changes have been described earlier in my testimony, including the establishment of a provision where, if a SGS customer's accumulated consumption in the current billing month and the month preceding meets or exceeds 24,000 kWh, the SGS customer will be moved to the MGS rate. Additionally, both a minimum billing demand and a maximum demand for eligibility in the new MGS rate were created and a new 138 kV rate is being proposed. Demand Charges for all TOU rates will be calculated consistent with the method used in the existing Rate LPS-90 class. Rate LLP-14 will be eliminated.

In TEP's last rate case, the Commission approved a 16.5% transitional credit for municipal customers in order to partially mitigate the significantly discounted rate that was available to municipal customers. Municipal customers enjoyed a substantial subsidy without providing any system benefits that justified the subsidy. The rates approved in the last rate case placed all former municipal customers that were on the former Rate PS-40 on the same rates as a standard general service customer, Rate GS-10, while offering a 16.5% discount to moderate the bill impact. The Company proposes to take the next step towards bringing municipal customers' rates in line with other similarly situated customers and eliminate the discount.

a. <u>Monthly Charges – Basic Service Charge and Demand Charges.</u>

Q. What monthly charge is TEP proposing for non-residential customer classes?

A. For SGS customers, TEP is proposing an increase to the basic service charges for the same reasons as discussed for the residential class, since no Demand Charge is in place for this class of customers. The proposed basic service charge will reflect an increase from the current $15.50 and $17.50 per month to the proposed $30.00 per month for both

standard and TOU rate classes. The SGS class will have a provision introduced that a customer will be moved to the new MGS rate in the subsequent month if a SGS customer's two month accumulated consumption in the current billing month and the month preceding meets or exceeds 24,000 kWh.

For the MGS class, the basic service charge will be $40 per month. As set forth in Schedule G-6-1, line 32, the proposed MGS charges are still below the true costs of providing service. Additionally, the MGS class will maintain a minimum billing demand of 20 kW. A new cap of 250 kW will be established such that any customer meeting or exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the LGS rate class. The customer must remain there for at least 12 months without exceeding the 250 kW demand to qualify to move back to MGS.

The LGS class will have a minimum billing demand of 200 kW and the basic service charge will be established at $1,000 per month. The LGS-TOU class will be the same. Even though a MGS customer will be moved to the LGS class if their demand meets or exceeds 250 kW, the minimum billing demand will remain at 200 kW, and the cap on demand for eligibility in the LGS classes (both non-TOU and TOU) will be established at 5,000 kW, at which point they will be moved to the LPS-TOU class. Since Rate LLP-14 is being canceled, once this level is achieved, the customer will only have a TOU rate available.

While there is no distinct rate, the current LPS-90 class contains two types of customers. Service is taken at either less than 138 kV or greater than or equal to 138 kV, with the basic service charge currently established at $2,000 per month. As mentioned earlier, most of the customers in this class receive service at less than 138 kV and will remain in the LPS-TOU rate class and will be served at a basic service charge of $2,000. Aside

from updating the rates in this class, no other major changes are being proposed for this class. For the LPS-TOU class, the current minimum billing demand of 3,000 kW will continue to be applied to all customers within the class.

The Company is also proposing a new 138 kV rate. This will only be available to service points where a customer has facilities in place to receive service at 138 kV. The minimum demand billed to any customer receiving service under this new rate schedule will be 10 MW. The basic service charge will be $3,000 per month and will have summer and winter demand charges of $17.15 and $14.15 per kW, respectively, with off-peak excess demand charges similar to the existing Rate LPS-90 class. The volumetric delivery charge will only be $0.0071 per kWh. The customers on this rate will pay slightly lower base power charges than those on LPS-TOU due to this class not being allocated distribution level system losses. The class will be responsible for all of the transmission and generation costs allocated to the Rate LPS-90 class and a slightly reduced level of distribution related costs. While some distribution plant related costs may not be used by this group of customers, they do benefit from the A&G related costs and many of the other miscellaneous plant costs.

Based on the results of the CCOSS, the Company believes these new basic service charges are just and reasonable as they will help levelize the class's contribution to the cost of service while still allowing the Company to recover more of its fixed costs through a fixed charge.

b. Calculation of Demand Charges.

Q. How is the Company proposing to calculate demand charges?

A. As discussed above, TEP is proposing to maintain the way it calculates the Demand Charges in those firm non-TOU rate tariffs where a Demand Charge is part of the rate design. This would include the existing LGS-13 rate tariff and the new MGS rate tariff.

The LPS-TOU Rate monthly billing demand will remain unchanged and that demand billing process will be applied to the billing process for the new MGS-TOU class, the LGS-TOU class and the new 138 kV class. The billed demand will be the greater of the following:

(i) the greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;

(ii) 75% of the greatest on-peak period billing demand used for billing purposes in the preceding 11 months; or

(iii) the contract capacity or 3,000 kW (20 kW for MGS TOU, 200 kW for Rate LGS-85 and 10 MW for the 138 kV rate), whichever is greater.

PLUS: the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak billed demand.

These provisions add consistency between the classes and allow the TOU customer the opportunity to save costs in recognition of moving load to off-peak periods.

The Company is proposing to apply one general method to the non-residential non-TOU rate classes that is the same as the method used for the current LGS class. In applying sound cost of service principles, the Company wishes to maintain the billing demand based on the "ratchet" being set at the levels defined above and in the tariffs.

Consistent with the criteria in the current LGS and proposed MGS tariff, monthly billing demand shall be the greater of the following:

(i) the greatest measured 15-minute interval demand read of the meter during all hours of the billing period;

(ii) 75% of the greatest demand used for billing purposes in the preceding 11 months; or

(iii) the contract capacity or 200 kW (20 kW for the MGS class), whichever is greater.

In most of the larger non-interruptible rate classes with a demand charge, the current CCOSS results indicate they are paying more than the levelized system return on plant as can be seen in Schedule G-2 –Proposed Rates, line 38. Therefore, the Company is proposing to make only moderate changes to the demand charge as set forth in Schedule H-3.

This design continues to allow higher load factor customers to benefit from their current usage patterns, which reflect a more efficient utilization of the system and is consistent with sound rate making principles.

c. **Volumetric Rates.**

Q. What is the Company proposing for the non-residential volumetric rates?

A. Any remaining authorized revenue requirement allocated to these classes will be recovered through an adjustment to the per-kWh delivery rate for the specific class. The volumetric rates vary by class and can be found in Schedule H-3.

Q. Currently, the tariffs that apply to some of TEP's large customers include a charge if they fall below a certain power factor. Is the Company proposing to change this tariff provision?

A. Yes. The Company is proposing to change the way the power factor is applied and billed in the large power service tariffs (Rates LPS-90 and 138 kV). The Company is proposing to change the current tariffs' power factor related charges to a method that matches what is currently in place for TEP's sister company UNS Electric. This method tracks the amount a customer's monthly power factor varies from 100% and applies the current tariff's demand charge to the equivalent demand calculated from the power factor variance from 95%. TEP will also apply the provision in its Rules and Regulations that allows the Company to require installation of power factor correcting equipment on a regular basis, if the provision in the tariffs does not encourage the customers to operate at improved power factors.

The Company is proposing to add language to the proposed 138 kV rate that will require a customer to install equipment that will allow for calculating and tracking the Power Factor to allow for appropriate billing when the customer's equipment places a burden on the system. Additionally, for current LGS rates a provision will be included that will allow the Company to require equipment to be installed to monitor the customer's Power Factor in circumstances where the customer's usage habits are detrimental to the system.

3. TOU Rates.

Q. What changes is the Company proposing to its TOU rates?

A. As discussed above, the Company is proposing to add tiers to all TOU rates at the same consumption level as in the comparable non-TOU rates. In the interest of simplifying the TOU rates in the Company's last rate case, all the tiers were eliminated in the residential and SGS TOU rates and only a single on-peak and single off-peak rate are included in the tariffs, varying by season. After reviewing customers' usage and the associated bills, it was determined that an inadvertent incentive was created for the largest customers to shift to TOU without changing consumption patterns. As a result, the Company is proposing to maintain the same tier rate structure between the non-TOU and TOU rates to encourage TOU customers to move consumption from the on-peak hours to the off-peak hours. Adding the tiers back to the residential TOU rates will result in price signals that are more consistent with the non-TOU rates with an incentive to move their consumption from on-peak hours to off-peak hours in order to generate savings on their bill. The Company is also proposing to retain the current Residential Super Peak TOU rate with only conforming changes (i.e. modify the tier break points to match the proposed Rate R-01 design) and updating the rates and basic service charge.

Additionally, with the proposed increases in the Basic Service Charges to more appropriate levels for all classes, the residential TOU customer's Basic Service Charge will be the same as the rate proposed for the R-01 rate.

The SGS-TOU rate will experience a larger increase overall due to the inadvertently low rate that was proposed by TEP and approved in the Company's last rate case. The elimination of the tier in Rate GS-76 (SGS-TOU) resulted in the unintended consequence of overly reduced rates for the class. The Company seeks to correct that error in this case

by proposing TOU rates for the small general service customers that are comparable to the non-TOU SGS rates. This will provide the necessary incentive for TOU customers to modify their peak consumption to save on their bill when compared to the Rate GS-10 rates in effect. The rates proposed are similar to the equivalent standard service rate with TOU based on-peak and off-peak fuel costs.

4. <u>Lighting Rates.</u>

Q. What changes are being proposed to TEP's Lighting Rates?

A. The Company is proposing to continue updating its lighting rates. Lighting services are designed to be offered to lighting conditions where no meter is installed. The prices vary by "equivalent" wattage and type of light bulb. This change is being proposed to allow for charges more in line with the cost of providing fixtures for LED lights. Once more lights have been installed in the Company's service territory, an analysis will be performed to determine if an increase in charges for LED lighting is warranted. The service includes the recovery of the initial cost of the pole, wiring, and fixture, as well as a normalized cost to maintain the light itself. The maintenance costs have continued to increase, however the rates have not kept up.

The lighting rates were substantially below the cost of service levels in TEP's last rate case and required an increase to bring them up to the appropriate levels. The Company's current review indicates that the lighting rates are being heavily subsidized and increases are warranted. The proposed rate increase, although higher on a percentage basis than most other classes, will not fully recover the costs incurred to serve the lighting customers.

5. **Community Solar Rate.**

Q. Will the Community Solar rate be changed?

A. Yes. The existing rate will be locked in place for the remainder of the customer's 20-year agreement. A new rate based on the revised fuel cost will be calculated and have the same, Commission approved, $0.02 per kWh premium added to it and placed on the Community Solar tariff for use by any customer signing up after the effective date of the new rates. This is the same process approved in the Company's last rate case.

The existing frozen Community Solar rates have a 20-year term and are based on fuel costs established in prior rate cases. For customers being migrated from the current SGS rate to the MGS rate, they will pay the MGS delivery rates, but will be allowed to maintain the fixed Community Solar rate for the energy blocks they currently have. They will only need to pay the new MGS Community Solar rate if they choose to purchase new blocks or replace blocks they dropped.

6. **138kV Rate.**

Q. Please describe the customer eligibility requirements for 138kV rate and the character of service they will receive.

A. This is a firm full-requirements service (three-phase, 60 Hertz, Primary Service) offered to customers taking service at a delivery voltage of 138kV or higher and delivered at a single point of delivery. Customers taking service on this rate are subject to a 10,000 kW minimum monthly billing demand. Fixed and variable costs are allocated to customers in this class assuming only transmission level losses. I have included the proposed tariff in **Exhibit CAJ-3** (Sheet No. 301).

Q. How is the cost of the 138kV+ system currently recovered from customers?

A. The cost of this system is part of the Company's Transmission system and is currently recovered through the assignment of the Company's current Open Access Transmission Tariff ("OATT") to retail customers as part of their operating expenses. The OATT currently recovers transmission system costs including losses from all customers. All distribution costs are recovered from customers, including LPS-90 customers, as determined in the CCOSS.

Q. Have you prepared a 138kV+ Rate?

A. Yes. I have prepared a tariff and the related rates for a single point of delivery when the customer takes service at 138kV and above.

Q. Please describe how you calculated this rate.

A. I supervised the inclusion of a specific rate class in the Company's cost of service study (Schedule G) for 138kV service. For class allocation purposes I requested the following assumptions be used in the study for the 138kV rate class:

1. Non-Coincident Peak Allocator (Fixed distribution costs and certain distribution expenses) – applied on transmission losses to derive this allocator that is used to allocate certain limited distribution functionalized and classified plant and expenses.
2. Distribution Plant Account Nos. 360-368 – for these distribution plant accounts (land & rights, structures and improvements, station equipment, poles, towers fixtures; overhead and underground conduits, and line transformers) the study did not assign any distribution functionalized and classified plant costs and related expenses to this class. In addition, the study

removed any plant and associated expenses related to Services (Account No. 369).

3. Average and Excess Factor– apply only transmission losses to derive this allocator that is used to allocate certain functionalized and classified fixed production costs.
4. Customer Costs Allocator – assume a single meter/customer count for the purpose of deriving the factor allocating functionalized and classified meter and customer information plant costs and related expenses.
5. Energy-related costs (fuel and variable O&M) – do not assign distribution losses to the sales units used to derive the energy cost allocator to this class.
6. Other costs – I requested no other changes related to allocators for all other costs not specifically identified in the items above.

Q. Do you believe this cost of service treatment is appropriate for the 138kV rate?

A. Yes. Under this approach a customer taking transmission level service at 138kV or higher voltage will avoid paying certain distribution plant costs and related expenses that are not used to provide service; in addition, only transmission losses have been assigned to the NCP allocator for these costs to properly reflect the higher voltage level nature of the service. Other costs such as fixed production costs and energy related costs are allocated using transmission losses only. The rate also appropriately recovers through the basic service charge, the costs of the 138kV meter as well as related customer information and general expenses – all of which are not avoided by customers taking service on this rate. Because of these facts, I believe the rate properly reflects sound cost causative factors that results in an appropriate level of costs assigned to customers on this rate while also avoiding any undue subsidy to this class by other rate classes.

7. **Interruptible Rates.**

Q. Please describe what changes the Company is proposing for the Interruptible Rate class.

A. The Company proposes to maintain the current Interruptible Rider. This rider provides for a customer to pay standard tariff rates, but allows the customer to designate a portion of their load as interruptible and receive a credit on their bill for the amount of capacity they offered as interruptible. This results in a more cost based credit for the real value of interruptible capacity in the year it is offered and protects the remaining customers. The rider can be seen in the attached **Exhibit CAJ-3** (Sheet No. 712).

8. **Economic Development Rate.**

Q. Is the Company proposing an Economic Development Rate ("EDR")?

A. Yes. TEP witness Dallas J. Dukes describes the EDR rider in detail. I have included the proposed rider in **Exhibit CAJ-3** (Sheet No. 713).

9. **Lifeline Rates.**

Q. What is the Company proposing with respect to its Lifeline rates?

A. The Company's low income rates are referred to as Lifeline rates. The Company proposes to simplify the currently available Lifeline rates by offering a single uniform discount off of each of the residential rates. The modifications would reduce the 27 existing tariffs, which contain multi-leveled percentage discount variations as well as fixed discount variations, down to five different open rate options, one for each of the five existing residential rates and apply a flat $15.00 per month discount (limited to a

reduction of the bill down to zero dollars.) The Company is also proposing changes to its frozen Lifeline rate options that will reduce them from 22 to five different options.

The combination of these rate discounts totaled $1,798,110 during the test year for nearly 15,000 Lifeline customers.

Q. Please describe the current Lifeline rate structures.

A. There are five Residential rates: R-01, R-80, R-201A, R-201B and R-8. Each of these rates has a fixed discount option in place for a customer who qualifies for a Lifeline discount. Currently that flat discount is $9.00 per month regardless of the class the customer chooses and regardless of the consumption. This makes for a simple to understand and simple to administer $108.00 annual discount for each qualifying Lifeline customer.

Where the Lifeline rates become complicated is when one considers all of the Lifeline variations that have been created and grandfathered for different usage levels over the last couple of decades. Some of these "frozen" rates were frozen in the mid 1990's. Some of these current discounts exceed $500 per year. This is as much as a 46% discount from the equivalent full retail rate for which the customer would otherwise qualify. With 27 different variations of Lifeline discounts that differ by consumption in any given month and also apply to Bright Community Solar customers, net metering customers and even Super Peak TOU customers, it has become overly burdensome to train customer service representatives to explain the variations, maintain the multiple tariffs needed to explain the variations and maintain and update the processes in the billing system. Also noteworthy is that 11 of the 27 different Lifeline rates contain fewer than 20 customers, and two of the rates being maintained have just one customer on them.

Given the situation set forth above, the Company is proposing to simplify its Lifeline rates so that: (1) customers can better understand these rates; and (2) the Company can more efficiently manage these rates. The Company is proposing to reduce the number of Lifeline rates from 27 to 10, five of which will continue to be available to new customers. All existing Lifeline customers on rates that are not frozen will stay on the fixed credit version of the Lifeline rate that they are currently on. The discount for these customers will be increased to mitigate a portion of the overall impact on bills and the discount will be applied in a way that most typical Lifeline customers will experience a total dollar increase on an annual basis that is in a range similar to the dollar increase for a non-Lifeline residential customer. Most of the Lifeline customers on the old frozen rates will have the same fixed discount available to them as the open Lifeline rates but the frozen Lifeline customers will have a lower basic service charge of $12.00 per month since they were receiving substantially larger discounts. One of the proposed frozen Lifeline rate will receive an even larger fixed discount (in combination with the $12.00 per month basic service charge) due to the very large subsidy they were receiving in the past. The amount of the discount will be one of two amounts for the various types of customers, but in general will be designed to moderate the amount of the increase.

Q. Please describe the new Lifeline rates that TEP is proposing.

A. Any new customer qualifying for the Lifeline program (or existing Lifeline customer moving to a new location) will become a standard residential R-01 (or R-80, R-201A, R-201B or R-8) customer and pay a non-Lifeline residential rate with a flat $15.00 per month discount applied to the bill (with the discount limited to no more than the actual bill in order to prevent a bill from being below zero).

Q. What will happen to customers who are currently on a frozen Lifeline rate?

A. The Company is proposing to maintain frozen Lifeline rates for the existing customers on a frozen Lifeline rate, but redesign the rates and create only five new options for the different types of residential customers. Customers on the new frozen Lifeline rates will experience a rate increase, but the increase will be limited for most and will still provide the customer with a substantial discount from the bill a standard non-Lifeline residential customer would pay. This discount will no longer be a percentage based discount that varies based on the customer's monthly consumption but will be a flat discount that varies from $15.00 per month up to $20.00 per month. This will still provide an annual discount of between $180 and $336 per year (based on a $15.00 to $20.00 per month discount and a $12.00 per month customer charge for the frozen rates).

10. <u>Prepay Rate.</u>

Q. Is the Company proposing a Prepay Rate?

A. Yes. TEP witness Denise Richardson-Smith describes the Prepay Rate and the details of why the Company believes it is a service the Company's customers want. I have included the proposed tariff in **Exhibit CAJ-3** (Sheet No. 108).

Q. Is the Rate available to all customers?

A. No. It is only available to standard Residential customers.

Q. Is it designed to be used in conjunction with any other tariff offering or riders?

A. No. It is a tariff service that cannot be used with other riders such as the Bright Tucson Community Solar rate, the Residential Solar – Company Owned Program, net-metering or Lifeline.

Q. How is the Prepay Rate calculated?

A. The rate is based on the Residential R-01 rate. It has a blended per kWh rate that is based on the weighted average of the two rate tiers on Rate R-01. However, a stepped rate has been proposed to avoid creating an average rate that automatically becomes an economic choice for large users. To prevent this from becoming an issue, an increased rate is applicable to any usage in excess of 20 kWh in a 24-hour period.

The rate also has a daily basic service charge. The basic service charge is based on the $20 monthly basic service charge proposed for Rate R-01 plus $2 per month to cover the cost of the cellular system needed to support the new rate; $1 per month to cover a portion of the added cost associated with the meter required to provide this service; and $2 per month to cover the cost of integrating the data management necessary to offer the service. This results in a $0.84 per day basic service charge (approximately $25.20 per month). The rates and tariff provisions can be found in **Exhibit CAJ-3** (Sheet No. 108).

11. <u>Alternative Generation Service Experimental Rider.</u>

Q. Why is the Company presenting an Alternative Generation Service Rider?

A. As part of the Settlement Agreement in the acquisition of UNS Energy by Fortis, UNS Energy agreed that UNS Electric and TEP would submit an alternative generation service tariff in their next rate case applications.

Q. Does the Company support approval of an alternate generation service rider in this proceeding?

A. No. The Company does not support it, and in fact, is opposed to the implementation of this tariff. It allows for certain large customers to "cherry pick" currently available

capacity resulting from short-term energy market conditions and will ultimately result in costs being shifted to the remaining customers.

Q. Please describe Experimental Rider 14, Alternative Generation Service the Company is presenting?

A. Experimental Rider 14, Alternative Generation Service, if approved, would be an optional, experimental program designed to provide an alternative generation arrangement for participating LPS-TOU or 138 kV customers. It would be available for a maximum of 30 MW of peak load and would be available for no more than four years from the effective date of new rates in this docket.

Under the program, the customer would select an approved wholesale generation service provider to sell power to the Company on the customer's behalf. The power must be delivered to one or more of the Company's points of delivery for wholesale power, as designated in a power supply agreement. The Company would take title to the power and provide it to the customer, who in turn would pay for the power pursuant to the terms and conditions in the power supply agreement, the terms of Experimental Rider 14, and other program provisions. TEP would continue to supply all retail services to the customer under the provisions of the customer's current retail rate schedule and the customer would continue to pay all non-fuel rates specified in that tariff. The customer would also be subject to all of the charges and adjustments in the retail rate schedule, except for Base Power Supply Charges and the PPFAC.

The Company would purchase and manage this generation on behalf of the customer for a management fee of $0.0040 per kWh. The Company would also provide scheduling and energy imbalance service. Furthermore, the billed amounts under the retail rate and

applicable adjustments would be based on the total billed kWh, kW, or billed dollar amount, including the cost of the alternative generation.

Q. Who could participate?

A. The program would be available to customers in the LPS-TOU and 138 kV rate classes with peak demands of 3,000 kW or more. As stated above, the program is limited to a total of 30 MW of peak load.

Q. How would customers be selected?

A. The Company would establish an initial enrollment period during which eligible customers could apply for the program. If the total MW of peak load from the applications exceeds the program maximum, customers would be selected for enrollment through a lottery process to be developed by TEP.

Q. What happens if the alternative Generation Service Provider defaults or the customer wants to return to standard TEP generation service?

A. The customer will be required to contract for service under this schedule for at least one year, but no longer than the termination date of the offering, if approved. If the alternative generation service provider defaults, the customer would have 60 days to find an alternate supplier or be considered a "returning customer". Default provisions would be specified in the power supply agreement.

If the customer desired to return to the standard TEP generation service before the contract term, due to a default or other reason, they would be allowed to do so without charge if: (1) they provide at least one year notice to the Company; (2) if the rider is discontinued at the end of the four-year experimental period; or (3) the Commission terminates the program prior to the end of the four-year experimental period. Absent one of these three conditions,

the Company would provide the customer with generation service at market rates specified in the rider, which include a premium, until the Company was reasonably able to integrate the customer back into their generation planning and provide power at the applicable retail rate schedule. I have included the proposed tariff in **Exhibit CAJ-3** (Sheet No. 714).

C. <u>Bill Impacts.</u>

Q. What is the bill impact of TEP's rate design proposals?

A. The bill impact of any rate case on the Company's customers is always TEP's paramount concern. A great deal of time and effort was put into creating a set of rates that would keep the impact on the customers within a reasonable range and be generally consistent with other similarly situated customers. These impacts have been summarized in **Exhibit CAJ-2.**

Additional bill impact data has been provided in Schedule H-4. **Exhibit CAJ-2** is based on current versus proposed fuel costs and current versus proposed rates for all bill calculations.

While Schedule H-4 reflects varying levels of energy consumption, **Exhibit CAJ-2** reflects bill impact comparisons by class by using "typical" usage amounts for each general rate class and uses the same level of consumption for like situated customers in order to create an "apples to apples" comparison of bill impacts. With respect to the residential classes, the comparisons reflect a customer that uses 1,150 kWh per month in the summer months and 785 kWh per month in the winter months. Residential customers under our basic residential rate (Rate R-01) will experience an increase of approximately 11.3%, which equates to just over $11.91 per month on average if the Company's full revenue requirement is approved. The Lifeline customers' existing rates are lower;

therefore, even though the percentage impact is higher than the Rate R-01 customer, the actual dollar change to the total bill for the same average monthly usage is generally the same total dollar increase or less as is proposed for the Rate R-01 customer for most of the classes. The Residential TOU customers will experience increases necessary to correct the pricing currently embedded in the TOU rates. Ideally, the customer should adjust their usage habits to experience a savings on a TOU rate. That has not been the case under the current rates; therefore the Company has proposed to adjust the TOU rates to address this issue. TOU customers that don't change their usage habits will pay approximately the same as a standard customer, but can experience a savings by shifting consumption to an off-peak period.

The bill impacts for the Residential classes are greater than what is being proposed for the larger classes in order to move toward a more equitable contribution to the overall return on plant identified in the CCOSS.

The overall increase the SGS customers will experience is an approximate 10.2% increase for the typical customer. The MGS class is new and will not have a former rate to compare to, but calculations have been made for all migrating customers and compared to the former GS-10 rate. Because these customers are migrating from two different rate classes, the range of expected bill impacts may be wider than typically experienced. The average bill increase for the class is approximately 10.7%. For all customers with increases at the high end of the range, individual concessions and communications will be made in order to mitigate the impact and allow the customer additional time if needed to adapt to the new rate design. The LGS customers will see an approximate 7.5% increase and the LPS customers will see an approximate decrease of 9.0 %.

All rates also reflect a realignment of non-fuel components to reflect results consistent with the CCOSS and an adjustment to fuel components to move customers closer to the average cost of fuel where appropriate. All of these changes are being proposed to reflect the recovery of costs more equitably between customers within a rate class and between rate classes.

IV. PROPOSED TARIFFS.

Q. Are you sponsoring the rate related tariffs TEP is proposing in this rate case?

A. Yes. The proposed rate-related tariffs will be submitted and attached to my Direct Testimony as **Exhibit CAJ-3** (clean copy) and **Exhibit CAJ-4** (redlined copy) shortly after this testimony is filed.

V. PRO FORMA ADJUSTMENTS

A. Weather Normalization Adjustment

Q. What is the purpose of a weather normalization adjustment?

A. Weather normalization is a standard adjustment commonly performed in rate cases. It is performed to provide a best estimate of test year sales, revenues, and costs as they would have been under normal weather conditions. Energy consumption for some of TEP's customer classes are weather sensitive. For instance, a significant portion of energy usage in the summer comes from air conditioning load. Some summers, however, are warmer than normal and result in the Company selling more power and receiving more revenues than in a "normal" year. The reverse of this occurs when cooler than normal summer weather is experienced. The purpose of weather normalization is to "average"

out these differences, so one can get a better sense as to what the Company is likely to receive in revenues during a year with normal weather.

Q. How has the weather normalization adjustment traditionally been calculated?

A. Historically, a typical industry practice was to use a variable known as heating degree days ("HDD") to measure heating load and another variable known as cooling degree days ("CDD") to measure cooling load. The theory has been that electric heating requirements are smaller when average daily temperatures are greater than 65 degrees Fahrenheit, and cooling requirements are smaller when the average daily temperatures are less than 75 degrees Fahrenheit. An HDD is measured by subtracting the average of the maximum and minimum temperature for that day from 65 degrees and a CDD is measured by subtracting 75 degrees from the average of the maximum and minimum temperature for that day. Negative results for both CDD and HDD calculations were set to zero. To obtain monthly HDD and CDD values, the daily values for each day of the month are summed.

The normal weather for each calendar month was assumed to be the average of the previous 10-years monthly CDD and HDD values as reported by the National Oceanic and Atmospheric Administration ("NOAA"). Actual monthly CDD and HDD for the TEP service area were then compared with the normal weather.

Q. Is this the method you are proposing to use in this proceeding?

A. No. The Company has developed a more precise method to weather-normalize sales which it has been using for its internal sales forecasts. The Company's refined method has consistently produced forecasts that are more closely aligned with actual results. Therefore, I am proposing it be used in this proceeding.

Q. Please describe the method you are proposing to use in this proceeding?

A. Much like the former method, NOAA-published information for the most recent 10-year period excluding the test year is utilized for the geographic territories served by TEP. Instead of two data points for each day being used as in the former method (the former method used the average of the high and low temperatures for each day to determine HDD or CDD for the day) the proposed method uses hourly average temperatures and hourly average dew points for each month. This data is directly out of the NOAA data base and is scrutinized through NOAA's validation process. Therefore it accurately reflects the actual temperatures in the area. Using 10 years of historical data allows the determination of a reasonable estimation of normal temperature and weather.

Q. Why change from the former Degree Day method to the proposed Average Temperature method?

A. The main purposes of the change in methodology are to more accurately capture the weather variability of sales and to isolate it from non-weather related effects. To accomplish this, a more accurate approximation of monthly weather is used, a trend variable is used to capture annual changes, and auto-regressive terms are used to capture non-weather related seasonal effects.

HDDs and CDDs were initially used as an approximation to daily weather and had several advantages to average temperature in the pre-computer era, since only two data points per day needed to be recorded and analyzed, thereby producing relatively easy calculations and requiring relatively small amounts of storage space. With the processing abilities of modern computers and available storage space, it is much easier, much less costly and much more accurate to use the more detailed average temperature (24 data points per day versus 2 data points per day) and average dew point data to approximate

normal weather. Thus, it is appropriate to use the more accurate weather approximation since there is no more difficulty to use.

Some other advantages to the proposed method result from the subjective definition of degree days. Degree days use a sense of "feel" to determine that heating dominates load below 65 degrees and cooling dominates load above 75 degrees. In reality, the Company's data indicates the residential class reacts to base temperatures of 62 degrees and the commercial class reacts to base temperatures closer to 50 degrees. Especially for the commercial class, this resulted in negative coefficients in winter months which the former method rejected and set to zero, thereby skewing the results and making them less accurate. The proposed method does not make subjective assertions as to which temperature heating or cooling load dominate, but instead allows the data to objectively establish that relationship.

Another disadvantage of degree days is they change linearly with temperature while the relationship of load to temperature is non-linear. To circumvent this problem, the degree day method used monthly weather coefficients where the new method accurately captures the non-linear relationship by using quadratic, and in some cases, cubic terms. The new method more robustly estimates the weather coefficients because each coefficient is based on more data points and they more accurately follow the load to temperature relationship. Further the model's accuracy was greatly improved but the model's complexity was actually reduced by eliminating variables. Thus, it is exceptionally clear that polynomial average weather coefficients are a superior weather variable compared to monthly degree days.

The proposed model also utilizes the effects of economic trends in its evaluation. Without a trend variable the regression process will attempt to explain some of the trend variation

by changing the weather coefficients which reduces their ability to accurately capture how weather affects sales. Thus, if the goal is to isolate the weather effect as much as possible, as it should be, then it is best to include a statistically significant economic variable that helps to explain the annual changes in load.

The final change to the model was for the treatment of seasonal effects influencing load that are not caused by the weather. Examples in our service territory include the seasonal migration of retirees and students moving to Tucson to attend the University of Arizona, Gem Show visitors or increased holiday hours for retail stores. These events occur roughly the same time each year and will influence load when they occur, but they are not events caused by the weather and should be isolated from the weather coefficients. In the degree day model, the use of monthly coefficients absorbed seasonal variations into the weather coefficient. Therefore, the degree day model did not properly separate weather from seasonal effects. In the average weather model, auto-regressive and moving average terms are used in conjunction with the weather variables in what is generally known as an ARIMAX model. The seasonal effects are handled very well by the auto-regressive and moving average terms which help to better isolate the weather from the seasonal effects. Thus, the average weather model estimates the true weather variability of load in a far superior way than the degree day model by isolating it from non-weather related seasonal effects.

Q. Was the weather normalization adjustment performed for all classes?

A. No. Weather normalization calculations were performed only for weather-sensitive residential, commercial and certain industrial classes, which were identified through regression analysis. Regression analysis revealed no statistically significant relationship between usage and weather for the large industrial, mining, or street lighting classes; therefore, no weather adjustment is proposed for these classes.

Q. What did your calculations show?

A. Overall, weather during the test year was more favorable for sales than normal. Therefore, actual sales were higher than normal resulting in a "negative" adjustment to sales volumes and revenues.

B. <u>Customer Annualization Adjustment.</u>

Q. Please describe the customer annualization adjustment.

A. The customer annualization adjustment revises the number of test year bills and volumes to be consistent with the number of customers on the system at the end of the test year. The Company is proposing to use the method that has been approved by this Commission in prior electric rate cases. The early months of the test year typically reflect more adjustment in the number of customers. For instance, the first month of the test year must be adjusted for 11 months of growth to reach adjusted test year end levels, whereas the eleventh month of the test year only requires one month of adjustment. Adjustments to the monthly volumes were made by multiplying the monthly bill count adjustment by the normalized usage per bill for the month.

Q. **Why is your customer annualization adjustment reflective of test year-end customer values, as opposed to some other adjusting point?**

A. The customer annualization adjustment – when added to normalized billing determinants – should result in adjusted billing determinants that will better reflect the bills and volumes at the time rates will be effective. Under the conditions described above and existing in this case, there is a nominal positive growth rate in the number of customers, and the last month of the test year reflects a customer count at or statistically close to the test year maximum. Therefore, the year-end adjustment technique results are the most accurate method to forecast the sales levels at the time new rates are effective. Also,

adjusting to year-end values provides a larger reduction in the rate increase versus adjusting to other test year levels, such as a mid-year level. The year-end technique is therefore the most effective in mitigating the rate increase TEP is requesting in this application.

Q. You mentioned earlier in your testimony that your largest customer recently announced its intent to reduce its consumption. Did you reflect this announcement in your annualization numbers?

A. No. The Company has not included it in the initial calculations being proposed in this filing. Although the customer has announced plans to curtail mining production by approximately 50% starting January 1, 2016, it is not clear at this time what exact impact this will have on the customer's energy and demand needs. As more information becomes available the Company will provide support and modifications to its filing, prior to the hearing in this case.

Q. What is the effect of the customer annualization adjustment on test year sales volumes?

A. As changes in the number of customers were reviewed and annualized, certain classes experienced increases, such as the Residential class. For the Small General Service class the test year number of customers was annualized and did increase slightly. However, due to the creation of the MGS class, many of those customers, based on the Company's evaluation of usage patterns, were moved to the new MGS class and in some cases to the LGS rate class. Additionally, for the larger rate classes, the standard customer annualization was calculated to reflect changes in customer counts or any identified substantial reduction in usage. For the entire rate class, counts were adjusted to reflect any likely migration the Company identified as highly probable due to redefined tariff

provisions. Ultimately, the annualization of test year sales resulted in an overall reduction in the sales volumes used as billing determinants to determine annualized revenues.

Q. **Why does the customer annualization adjustment have an impact on test year revenue and costs?**

A. As I mentioned above, even small customer annualization adjustments can affect the number of customers, kWh consumed, and kW demand. Any increase, even a small one, means that adjusted billing determinants would typically be adjusted upward. So, increasing these billing determinants increases both adjusted revenues and expenses. More specifically, incremental customer growth will increase revenue and certain expenses. In evaluating the test year activity for this filing, the normal customer growth has produced only a slight increase in billing determinants. The increase in billing determinants is smaller than what normally would have been expected as the result of items such as a decreased use per customer and reductions in overall sales due to the increase in distributed generation and the continued promotion of energy efficiency. All are beneficial to society as a whole, but result in less sales volumes to spread costs to. In this case, when all adjustments are made, the incremental net margin (the difference in revenue and expenses) is negative. Therefore, because the incremental net margin is negative, that will decrease the total operating income and increase the total revenue increase thereby increasing the revenue deficiency identified in this proceeding

C. Transmission Expense Adjustment.

Q. Please describe the Company's treatment of transmission costs.

A. TEP's retail rates include transmission costs based on TEP's FERC-approved Open Access Transmission Tariff ("OATT") rates applied to TEP's transmission system. TEP's retail customers use the transmission system to bring energy from the source to the TEP

distribution system. Accordingly, transmission expenses which are included as an O&M expense are based on the FERC approved OATT rates being applied to the adjusted test year billing determinants associated with only native load.

VI. SERVICE FEES.

Q. Please describe the proposed changes in charges reflected on the "Statement of Charges".

A. The Company has reviewed the costs associated with providing these other various services to customers. This is being done during the rate case so any change in revenues resulting from changes to the rates can be accurately reflected in the Company's total revenue requirement. TEP has calculated updated charges after quantifying the actual costs of providing these services. These charges were then applied to the actual number of units of each service occurring in the test year. The incremental increase produced by these changes will reduce the overall revenue requirement allocated to general rates based on the weighted proportion each rate class contributes to the total revenues from these services. Please refer to attached **Exhibit CAJ-3** (Sheet No. 801), to see the specific charges the Company is proposing.

Q. Were any new service fees added?

A. Yes. The Company is proposing to establish a charge to provide customer usage data or interval data (if more than one request for standard usage data is made in a twelve-month period). The new charge is: (1) an hourly charge based on the time required to provide the data; (2) incremental to existing service fees; and (3) included in the revenue calculation. These charges can be found on **Exhibit CAJ-3** (Sheet No. 801).

Q. Will TEP offer an opt-out option for those customers that do not want an Automated Meter Reading ("AMR") meter that uses radio frequency for meter readings?

A. Yes. The Company is proposing to add language to the Rules and Regulations that provide for the cost-based charges and conditions associated with a Rate R-01 customer choosing to either not have an AMR installed or to have an AMR unit replaced in order to have an "analog" meter measure their electrical usage.

Q. Have any TEP customers requested to not have AMR meters installed?

A. Yes. So far, just over 1,000 customers or 0.25% of the Company's customers have indicated to the Company that they prefer not to have an AMR unit installed.

Q. Why should these customers pay additional fees to not have an AMR unit installed?

A. Currently the Company is installing AMR units throughout its service territory. The installation of AMR units allows for more automated meter reading and as a result a reduction in the cost to serve the customers. This reduction in cost is shared with all customers. AMR units allow for better tracking of any fraudulent or unauthorized use as well, which provides savings to all customers. Meter technology is advancing and analog meters will soon be obsolete, thereby making them much more expensive to purchase and maintain than AMR units. This means that customers expressing a desire to keep analog meters will cost the rest of TEP's customers more and more each year. It is the Company's position that the other customers should not have to pay for added expenses created by these 1,000 or so customers who have decided to make a unique and more expensive choice.

Q. What other costs are associated with offering these customers the opportunity to opt-out of an AMR unit?

A. Because analog meters prevent the use of a fixed network system that remotely reads meters and provides the data to the Company remotely, actual meter readers will need to be dispatched on a regular basis to physically read the meters. The large geographic area over which these customers may be located could make this a very expensive activity, resulting in incremental costs associated with labor, transportation, modified processes and equipment to maintain the manual reads and historical data, additional reporting requirements, etc. All of these are incremental costs that could be avoided if a standard AMR unit were installed. These costs should be paid by the customer with the desire to maintain soon to be obsolete equipment.

Q. Would special conditions need to be made if the customer chooses to opt out of the AMR meter?

A. Yes. Without AMR equipment installed, the customer would not be eligible to enjoy TOU rates, electric vehicle rates, net metering, pre-pay rates or any other service requiring more advanced meter reading equipment.

VII. MODIFICATIONS TO ADJUSTOR MECHANISMS.

Q. Is TEP requesting any changes to its adjustor mechanisms in this case?

A. Yes. I will address the Company's proposed changes to how the PPFAC mechanism is administered to customers' rates and modifications to the LFCR and ECA mechanisms. The Company's adjustor mechanisms will also be reset as certain costs are incorporated into TEP's new base rates.

A. **Purchased Power and Fuel Adjustment Clause.**

Q. How is TEP proposing to modify its PPFAC?

A. The PPFAC rate is currently adjusted annually and charged to customers on a per-kWh basis. The Company proposes to adjust the PPFAC monthly and allocate the PPFAC costs, as currently calculated, on a percentage of the average base fuel rate established in this rate case. The monthly PPFAC charge will be a single percentage adjustment applied to all base fuel rates for all customer classes.

Q. Why is TEP proposing to modify the methodology for allocating the PPFAC to the various classes of customers?

A. The Company believes this method better aligns the changes in fuel costs with each rate classes' base fuel costs. For example, suppose an LPS customer's base fuel is $0.03 per kWh and the residential base fuel cost is $0.05 per kWh. Under the current method a ($0.0003) per kWh PPFAC change is a 1% decrease to the LPS customer's fuel costs, but is only a 0.6% decrease to the residential customer's fuel costs and visa-versa if it were a $0.0003 increase. By using an overall percentage based adjustment to base fuel costs; a 0.5% PPFAC increase will equate to a 0.5% increase for all classes.

B. **Lost Fixed Cost Recovery Mechanism.**

Q. Describe what additional fixed costs the Company proposes to recover through the LFCR.

A. Currently, the LFCR mechanism excludes recovery of the Company's fixed costs attributable to generation and fixed must run. Fixed must run is a separate distribution related service supplied by generation facilities (fixed must run will be included in my reference to "generation" for purposes of this section of my testimony). Therefore the

current LFCR mechanism prohibits the recovery of these fixed costs from customers when sales decline as a result of EE programs and DG. Additionally, the current LFCR only allows the recovery of 50% of the non-generation demand charges. The Company is proposing to update the LFCR to allow recovery of lost fixed costs attributable to generation as well as the full recovery of lost demand revenues.

Q. Why do you believe the generation related costs should be included in the value of the lost sales?

A. Since TEP's last rate case, the level of EE and DG has increased as has the level of unrecovered fixed costs necessary to provide safe, reliable service.

Q. Have you been able to recover any of the generation costs and related charges that were avoided by retail customers participating in mandated EE and DG programs?

A. No. Even if the Company was able to market its available generation, any revenue from that sale would go to the benefit of the PPFAC customers as a reduction to fuel costs, thereby reducing the end-users costs, but in no way aiding the Company in the recovery of its lost revenue.

Q. What is the Company's estimate of the lost revenues from compliance with the EE Standard and REST attributable to generation and the reduced demand charge?

A. Based on the kWh and kW losses reported in TEP's 2015 LFCR filing, the Company's estimate is that the lost revenue associated with excluding the generation components and reducing the demand charges is approximately $13 million.

Q. What is the Company proposing to do to fix this under-recovery associated with removing 50% of the demand charge and all of the generation costs from the LFCR calculation?

A. The LFCR rates used in the schedules to quantify the dollar value assigned to the lost kWh and kW should be fully reflective of the non-fuel energy rates and demand charges in each class. For tiered rates it should be the tail block rate since that is the most likely level where lost sales would occur. Since the calculation of demand-related losses specifically identifies the actual amount of offset to the customer's peak demand, the demand losses should be valued at the entire demand rate, not the current 50%.

Q. What other changes to the LFCR POA is the Company proposing?

A. Clarifying language has been included to make it consistent with the intent of the process. The main example is for DG related losses, the current spreadsheet specifies that last year's total losses be added to this year's new total. However, since we are calculating DG losses based on current production meter reads (less the production reads during the test year), it inherently captures losses from all systems and does not need to include the carry-over from the prior year. We have removed that reference in the worksheets. Another example is our proposal to eliminate the residential LFCR Fixed Cost Option. As of the preparation of this testimony, there were no collections from this option. Therefore, the Company is proposing to remove the option of paying the LFCR as a fixed charge.

Another revision is the change from a 1% year-over-year cap to a 2% year-over-year cap. This was done because the current LFCR (with the 1% cap) removes generation related components and 50% of the demand in the rates for the calculation of lost revenue. When the generation costs and full demand charges are appropriately added back into the LFCR, it would also be appropriate to increase the cap to 2%. While the Company

agreed to the exclusion of generation in the settlement in the last rate case, the Company believes this unfairly understates the value of the lost sales and contributes to substantial under-recovery of lost revenues with no opportunity to recover them. Modifying the LFCR as proposed also promotes rate gradualism for customers. Another potential revision to the LFCR POA will be to include a provision that would allow for the recovery of any lost revenues resulting from any Alternate Generation Service rider that may be approved. This provision was discussed in the section of my testimony addressing the Alternate Generation Service rider.

The Company is also proposing to simplify the percentage-based LFCR Adjustment to be a single rate applied to customers' bills, rather than split the adjustment into two separate rates for EE and DG. Aside from these changes, we have also updated the LFCR to add consistency between the POA and the related schedules, and we have also updated the schedules to include sections for any new rate classes proposed in this filing. The Company's proposed changes to the LFCR POA and schedules are included as **Exhibit CAJ-5** in both clean and redline form.

Q. Does the Company wish to maintain the option for residential customers to choose to contribute to the LFCR in the form of a fixed charge instead of the percentage rate?

A. No. No customers have selected this option since it was adopted in the last rate case.

Q. Has the LFCR resulted in a large surcharge to customers?

A. No. First, the current annual 1% year-over-year cap reduces the impact of the LFCR to the customer. The combined EE and DG surcharge from the first TEP LFCR filing was approximately 0.7% and the 2015 LFCR filing resulted in approximately a 0.4% incremental increase for a total adjustment of approximately 1.1%. However, based on

the data supporting the 2015 LFCR filing, the Company estimates that the incremental LFCR increase for including generation costs would have incrementally increased the total LFCR adjustment by an additional 1.7% to a total LFCR adjustment of 2.8%. However, our proposed increase to the basic service charges would collect a greater portion of the Company's fixed costs and partially offset the total dollars subject to adjustment in future LFCR adjustments.

The Company is proposing an annual year-over-year cap of 2% of total applicable revenues to provide for the changes in the LFCR that are being proposed.

C. <u>Environmental Cost Adjustment.</u>

Q. How is TEP proposing to modify its ECA?

A. The ECA rate is currently capped at a $0.00025 per kWh rate which was a cap based on 0.25% of prior test-year annual revenues. Based on current sales levels, this cap limits the total expenditures on environmental improvements that are recoverable between rate cases to approximately $2,000,000 per year. The Company expects annual ECA eligible costs related to environmental compliance to be at, or above, $4,000,000 per year. Therefore, the Company is proposing to increase the cap to allow for more timely recovery of a greater portion of its environmental compliance costs. The Company is also proposing that the ECA charge be converted from an energy-based charge to a percent-based charge. To be in conformity with that modification, the case should be converted to a percentage-based cap instead of the current kWh rate. The Company proposes that the new ECA cap level be set at 0.50% of annual revenues year over year. This will allow for a more equitable contribution for all classes. A revised POA for the ECA has been included as **Exhibit CAJ-6**.

D. Demand Side Management Surcharge.

Q. How is TEP proposing to modify its DSM?

A. The DSM rate is currently charged as a per kWh adjustment to the residential class and a percentage based charge for all other classes. The Company is proposing to apply the charge as a percentage based adjustment to all classes with the effective date of the next DSM filing.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit CAJ-1

Tucson Electric Power
Marginal Cost Study (2015)
Summary

CAJ-1
Schedule 1

Line	FERC A/C	Description	Residential Service	Small General Service
1		**Billing Determinants**		
2		Customer-Months	4,624,515	462,775
3				
4		**Customer Installation Annual Carrying Costs ($)**		
5	370	Meters	$ 37.19	$ 43.56
6	369	Services - Overhead/Underground	$ 10.13	$ -
7	368	Line Transformers	$ 81.49	$ 858.19
8	365-367	Conductors & Devices - Overhead/Underground	$ 148.28	$ 1,626.97
9	389-398	General Plant	$ 10.49	$ 40.47
10		**Subtotal: Customer Annual Carrying Costs**	**$ 287.58**	**$ 2,569.19**
11				
12		**Customer O&M Costs**		
13	902	Meter Reading Expenses	$ 3.62	$ 3.60
14	903	Customer Records & Collection Expenses	$ 41.33	$ 41.16
15	904	Uncollectible Accounts	$ -	$ -
16	905	Customer Accounts Expenses Supervision	$ -	$ -
17	908	Customer Assistance Expenses	$ -	$ -
18	909	Informational and Instructional Advertising Exp.	$ 0.45	$ 0.45
19	910	Misc. Customer Service & Informational Exp.	$ 0.24	$ 0.24
20	920-935	Customer A&G Costs	$ 20.65	$ 20.56
21		**Subtotal: Customer O&M Costs**	**$ 66.28**	**$ 66.01**
22				
23		**Marginal Cost per Customer (Annual)**	**$ 353.86**	**$ 2,635.20**
24		**Marginal Cost per Customer (Per Month)**	**$ 29.49**	**$ 219.60**
25		**Marginal Revenue Requirement**	**$ 136,370,393**	**$ 101,625,600**

Tucson Electric Power
Marginal Cost Study (2015)
Customer Installation Investment Costs

CAJ-1
Schedule 2

Line	FERC A/C	Description		Residential Service		Small General Service
1		**Billing Determinants**				
2		Customer-Months		4,624,515		462,775
3						
4	370	**Meters**				
5		Investment ($/Meter)	$	216.00	$	253.00
6		ECCR		17.22%		17.22%
7		Unit Annual Carrying Cost ($/Meter)	$	37.19	$	43.56
8		Total Annual Carrying Cost ($)	$	14,332,043	$	1,679,883
9						
10	369	**Services - Overhead/Underground**				
11		Unit Cost ($/Ft, New Service)	$	1.74		
12		Footage (Ft)		75.00		
13		Investment ($/Meter)	$	130.42	$	-
14		ECCR		7.77%		7.77%
15		Unit Annual Carrying Cost ($/Meter)	$	10.13	$	-
16		Total Annual Carrying Cost ($)	$	3,903,197	$	-
17						
18	368	**Line Transformers**				
19		Unit Cost ($/Transformer, New)	$	2,548	$	8,944
20		Customers per Transformers		3		1
21		Investment ($/Cust.)	$	849.30	$	8,943.76
22		ECCR		9.60%		9.60%
23		Unit Annual Carrying Cost ($/Cust.)	$	81.49	$	858.19
24		Total Annual Carrying Cost ($)	$	31,405,641	$	33,095,766
25						
26	366-367	**UG Conductor & Devices**				
27		Junction Cabinet ($/Install)	$	3,812		
28		Number of customers per cabinate		30		
29		Avg. Cabinet Investment ($/Cust.)	$	127		
30		Primary Conductor - Unit Cost ($/Ft)	$	9.41	$	29.14
31		Primary Conductor - Footage (Ft/Install)		133		500
32		Secondary Conductor - Unit Cost ($/Ft)	$	1.73		
33		Secondary Conductor - Footage (Ft/Install)		33		
34		Conductor Investment ($/Install)	$	1,312	$	14,569
35		Riser ($/Install)			$	2,717
36		Pedestal Unit Cost	$	273		
37		Number of customers per pedestal	$	2		
38		Pedestal Cost per customer ($/Cust)	$	136		
39		UG Conductor & Devices Investment ($/Install)	$	1,575.44	$	17,285.78
40		ECCR		9.41%		9.41%
41		Unit Annual Carrying Cost ($/Cust.)	$	148.28	$	1,626.97
42		Total Annual Carrying Cost ($)	$	57,145,071	$	62,743,609
43						
44						
45	389-398	**General Plant**				
46		General Plant - ECOSS Customer Allocation	$	33,492,683	$	12,935,882
47		Less: Accumulated Depreciation	$	(9,229,347)	$	(3,564,652)
48		Net General Plant - Customer Allocation	$	24,263,335	$	9,371,230
49		Return on Ratebase (Pre Tax)		10.2%		10.2%
50		Return on Ratebase (Pre Tax)	$	2,474,860	$	955,865
51		Depreciation Expence	$	1,565,922	$	604,806
52		Total Annual Carrying Costs ($)		$4,040,782		$1,560,672
53		Unit Annual Carrying Costs ($/Cust.)	$	10.49	$	40.47

Tucson Electric Power
Marginal Cost Study (2015)
Customer O&M Costs

CAJ-1
Schedule 3

Line	FERC A/C	Description	Residential Service	Small General Service
1		**Billing Determinants**		
2		Customer-Months	4,624,515	462,775
3				
4	902	**Meter Reading Expenses**		
5		Meter Reading Expenses	$ 1,393,664	$ 138,892
6		Expenses per customer	$ 3.62	$ 3.60
7				
8	903	**Customer Records & Collection Expenses**		
9		Customer Records & Collection Expenses	$ 15,926,207	$ 1,587,199
10		Expenses per customer	$ 41.33	$ 41.16
11				
12	904	**Uncollectible Accounts**		
13		Uncollectible Accounts	$ -	$ -
14		Expenses per customer	$ -	$ -
15				
16	905	**Customer Accounts Expenses Supervision**		
17		Customer Accounts Expenses Supervision	$ -	$ -
18		Expenses per customer	$ -	$ -
19				
20	908	**Customer Assistance Expenses**		
21		Customer Assistance Expenses	$ -	$ -
22		Expenses per customer	$ -	$ -
23				
24	909	**Informational and Instructional Advertising Exp.**		
25		Informational and Instructional Advertising Exp.	$ 173,278	$ 17,269
26		Expenses per customer	$ 0.45	$ 0.45
27				
28	910	**Misc. Customer Service & Informational Exp.**		
29		Misc. Customer Service & Informational Exp.	$ 93,880	$ 9,356
30		Expenses per customer	$ 0.24	$ 0.24
31				
32	920-935	**Administrative and General Expense**		
33		Administrative and General Expense	$ 66,049,810	$ 6,582,497
34		A&G Expense - Customer Allocation	$ 7,956,629	$ 792,954
35		Expenses per customer	$ 20.65	$ 20.56
36				
37		**Total Customer Expense**	$ 66.28	$ 66.01

Exhibit CAJ-2

Tucson Electric Power
Bill Impacts
Test Year Ending June 30, 2015

Class Description	Customer Counts 10/1/15	Average Summer kWh	Average Winter kWh	New Annual Bill	Annual Bill Change	$ Change from Standard Tariff	Revised Percent Change to Total Bill	Monthly $ change in bill
Residential R-01	341,759	1,150	785	$1,409.79	$142.88		11.3%	$11.91
Residential Lifeline R-01LL	6,812	1,150	785	$1,229.79	$70.88	($180.00)	6.1%	$5.91
Residential Lifeline R-04-01F	444	1,150	785	$1,073.79	$145.08	($336.00)	15.6%	$12.09
Residential Lifeline R-05-01F	1,067	1,150	785	$1,133.79	$58.71	($276.00)	5.5%	$4.89
Residential Lifeline R-06-01F	5,685	1,150	785	$1,133.79	$85.65	($276.00)	8.2%	$7.14
Residential Lifeline R-08-01F	572	1,150	785	$1,073.79	$291.52	($336.00)	37.3%	$24.29
Residential R-201A	11,221	1,150	785	$1,349.73	$152.12	($60.06)	12.7%	$12.68
Residential Lifeline R-201AL	198	1,150	785	$1,169.73	$80.12	($240.06)	7.4%	$6.68
Residential Lifeline 06-201AF	270	1,150	785	$1,073.73	$103.64	($336.06)	10.7%	$8.64
Residential Lifeline 08-201AF	9	1,150	785	$1,073.73	$342.21	($336.06)	46.8%	$28.52
Residential TOU R-80	8,001	1,150	785	$1,370.95	$247.09	($38.84)	22.0%	$20.59
Residential Lifeline TOU R-80LL	85	1,150	785	$1,190.95	$175.09	($218.84)	17.2%	$14.59
Residential Lifeline R-04-21F	2	1,150	785	$1,094.95	$273.60	($314.84)	33.3%	$22.80
Residential Lifeline R-05-21F	1	1,150	785	$1,094.95	$138.14	($314.84)	14.4%	$11.51
Residential Lifeline R-06-21F	17	1,150	785	$1,094.95	$193.86	($314.84)	21.5%	$16.16
Residential Lifeline R-08-21F	7	1,150	785	$1,094.95	$405.36	($314.84)	58.8%	$33.78
Residential Lifeline R-04-70F	6	1,150	785	$1,094.95	$216.10	($314.84)	24.6%	$18.01
Residential Lifeline R-05-70F	10	1,150	785	$1,094.95	$97.03	($314.84)	9.7%	$8.09
Residential Lifeline R-06-70F	54	1,150	785	$1,094.95	$120.76	($314.84)	12.4%	$10.06
Residential Lifeline R-08-70F	16	1,150	785	$1,094.95	$369.62	($314.84)	51.0%	$30.80
Residential TOU Super Peak R-8	162	1,150	785	$1,377.87	$293.38	($31.92)	27.1%	$24.45
Residential Lifeline TOU Super Peak R	4	1,150	785	$1,197.87	$221.38	($211.92)	22.7%	$18.45
Residential R-201B	645	1,150	785	$1,319.77	$279.30	($90.02)	26.8%	$23.28
Residential Lifeline R-201BL	2	1,150	785	$1,139.77	$207.30	($270.02)	22.2%	$17.28
Residential Lifeline 06-201BF	4	1,150	785	$1,043.77	$156.87	($366.02)	17.7%	$13.07
General Service R-10	35,396	1,886	1,340	$2,727.69	$252.54		10.2%	$21.05
SGS Time of Use R-76	1,167	1,886	1,340	$2,650.66	$275.07	($77.03)	11.6%	$22.92
General Service R-10 Municipal	840	1,886	1,340	$2,727.69	$630.25	$0.00	30.0%	$52.52
Mobile Home Park Service R-11	283	15,040	12,611	$20,176.91	$1,812.63		9.9%	$151.05
Municipal Water Pumping Service R-4	426	17,209	12,251	$18,756.94	$1,706.66		10.0%	$142.22
Municipal Interruptible WP Service R-	157	17,209	12,251	$14,123.82	$1,705.52	($4,633.12)	13.7%	$142.13
Medium General Service		24,544	17,563	$35,001.49	$3,369.00		10.7%	$280.75
Medium General Service TOU		24,544	17,563	$31,678.98	$3,169.43	($3,322.51)	11.1%	$264.12
Large General Service R-13	444	178,619	149,663	$204,808.97	$14,368.73		7.5%	$1,197.39
Large General Service TOU R-85	126	178,619	149,663	$193,090.71	$9,579.37	($11,718)	5.2%	$798.28
Large Power Service TOU R-90	18	6,174,912	5,193,148	$4,314,394.74	($424,533.73)		-9.0%	-$35,377.81
Traffic Signal& Street Light Service PS-	5,956	2,204	2,687	$2,863.66	$260.35		10.0%	$21.70

Tucons Electric Power
Bill Impacts
Test Year Ending June 30, 2015

Class Description	New Annual Bill	Annual Bill Change	Change to Standard Bill	Revised Percent Change to Total Bill	$ change in Mo. Bill
Residential R-01	$1,409.79	$142.88		11.3%	$11.91
Residential TOU R-80	$1,370.95	$247.09	($38.84)	22.0%	$20.59
General Service R-10	$2,727.69	$252.54		10.2%	$21.05
SGS Time of Use R-76	$2,650.66	$275.07	($77.03)	11.6%	$22.92
General Service R-10 Municipal	$2,727.69	$630.25		30.0%	$52.52
Medium General Service	$35,001.49	$3,369.00		10.7%	$280.75
Medium General Service TOU	$31,678.98	$3,169.43	($3,322.51)	11.1%	$264.12
Large General Service R-13	$204,808.97	$14,368.73		7.5%	$1,197.39
Large General Service TOU R-85	$193,090.71	$9,579.37	($11,718)	5.2%	$798.28
Large Power Service TOU R-90	$4,314,394.74	($424,533.73)		-9.0%	-$35,377.81

Exhibit CAJ-3

EXHIBIT TO BE LATE-FILED

Exhibit CAJ-4

EXHIBIT TO BE LATE-FILED

Exhibit CAJ-5

CLEAN

TUCSON ELECTRIC POWER COMPANY
LOST FIXED COST RECOVERY MECHANISM ("LFCR")
PLAN OF ADMINISTRATION

Table of Contents

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1. General Description

This document describes the plan of administration for the LFCR mechanism approved for Tucson Electric Power Company ("TEP" or "Company") by the Arizona Corporation Commission ("Commission") in Decision No. xxxxx (xxx, xx, xxxx). The LFCR mechanism provides for the recovery of lost fixed costs, as measured by a reduction in non-fuel revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the non-fuel energy costs included in base rates and the demand rates in effect, plus any amount quantified in the Balancing Account.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Balancing Account – A mechanism to track the difference between allowed Lost Fixed Cost Revenue and actual amounts billed by the Company through the LFCR adjustment. The balancing account will be reflected in Schedule 2 of the LFCR Compliance Report and shall be calculated by taking the Total Lost Fixed Cost Revenue from Prior Period less the amount billed through the LFCR for the most recent collection period at the time of filing.

Current Period – The most recent calendar year used to determine lost sales for purposes of LFCR recovery.

Delivery Revenue – The amount of revenue determined at the conclusion of a rate case by multiplying each participating rate class' adjusted test year billing determinants (kWh or kW) by their approved non-fuel energy and demand charges.

DG Savings – The amount of kWh or kW sales reduced by DG. TEP will use meter data for determining the kWh or kW lost through the implementation of DG systems unless a rare circumstance occurs where the meter data is not available at which time the lost sales will be quantified using statistical verification or output profile or other Commission authorized methods. Each year, TEP will use actual data through December to calculate the savings. The calculation of DG Savings will consist of the following by class:

1. Current Period: The total kWh or kW reduction metered during the period less the total kWh or kW reduction metered in TEP's most recent general rate case test year.

2. The only DG Savings that will be excluded from the Lost Fixed Cost Revenue calculation are those kWh or kW that were lost as the result of actions by customers on the Excluded Rate Schedules.
3. The annual kW capacity of the cumulative total of DG installations since the end of the test year used in TEP's most recent general rate case. For solar systems only, the actual kW capacity used to calculate lost revenues for applicable demand metered customers will be the actual solar generation measured by the Solar production meter coincident with the customer's maximum fifteen minute demand for the billing period.

EE Programs - Any program approved in TEP's Energy Efficiency/Demand Side Management ("EE/DSM") implementation plan or defined in the Commission's Electric Energy Efficiency Rules.

EE Savings - The amount of sales, expressed in kWh or kW, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Research Report ("MER") conducted for TEP's EE Programs. The Company's EE activities are being reviewed as part of the MER evaluation and will determine the total kWh or kW lost as a result of those activities. As part of this filing the Commission Staff will have the option of reviewing any portion of the filing they deem necessary to verify the filing's accuracy. EE Savings shall be quantified based on the cumulative lost kWh or kW occurring starting July 1, 2015 and shall reset as of the end of the test year in each rate case. The calculation of EE Savings will consist of the following by class:

1. Current Period: The annual EE related sales reductions (kWh or kW). Each year, TEP will use actual MER data through December to calculate savings.
2. Prior Period: The cumulative total kWh or kW reduction reported in the previous year's LFCR filing, recognizing that the cumulative total is reset (to zero) at the end of each of TEP's most recent general rate case. The first such reset was on January 1, 2012, (the end of the Test Year in Decision No. 73912.) Recovery of LFCR revenues quantified in the initial LFCR will continue until the first LFCR resulting from the current general rate case results in the specified reset to zero. With the approval of this rate case (Decision No. xxxxx) the cumulative total kWh and kW will be reset as of July 1, 2015 (the end of the test year) for calculations of the LFCR performed until reset in the Company's next general rate case.
3. Excluded kWh reduction: The reduction of recoverable EE Savings calculated by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules if included in the total reported in the annual EE/DSM filing.

Effective Period – The twelve month period beginning with July 1 of each year, when the LFCR will be charged.

Excluded Rate Schedules – The LFCR mechanism shall not apply to Traffic Signal and Street Lighting Service (TSL), Lighting Service (LS), Water Pumping Service (GS-WP), or the Large Power Services (LPS-TOU and LPS-138) rate schedules, or the Residential Solar – Company Owned Program.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue by the Applicable Company Revenues. This percentage-based LFCR Adjustment will be applied to all customer bills, excluding those on Excluded Rate Schedules.

Lost Fixed Cost Rate – A rate determined at the conclusion of a rate case by taking the sum of allowed Delivery Revenue (which excludes the Basic Service Charge and purchased power and fuel) for each rate class and dividing each by their respective class adjusted test year kWh and/or kW billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE Savings and DG Savings during the Current Period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh or kW Savings, by rate class.

Prior Period – The calendar year preceding the Current Period.

Recoverable kWh or kW Savings – The EE Savings and DG Savings by applicable rate class.

3. *LFCR Annual Incremental Cap*

The total LFCR Adjustment will be subject to an annual 2% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of 2%, in total, of Applicable Company Revenues, any amount in excess of the 2% cap will be deferred for collection until the next year its inclusion does not result in the 2% year-over-year cap being exceeded. Any deferred amounts, plus any amount quantified in the Balancing Account, will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the 2% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharges billed in the following year will first recover any such carried-over deferrals, as well as any Balancing Account balance, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

4. *Filing and Procedural Deadlines*

TEP will file the calculated Annual LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by May 15th of each year. Staff will use its best efforts to process the matter based on the results of the Company's annual EE/DSM and Renewable Energy Standard Tariff ("REST") filings such that a new LFCR Adjustment may go into effect by July 1st of each year. However, the new LFCR Adjustment will not go into effect until approved by the Commission.

5. *Compliance Reports*

TEP will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office by May 15th of each year. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1 : LFCR Annual Percentage Adjustment Rate
- Schedule 2: LFCR Annual Incremental Cap Calculation

- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: Delivery Revenue Calculation

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rate~~s~~

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
	~~Energy Efficiency Related Adjustment~~			
1	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15, Column C ~~(Sch 2, Line 15, Col C * Sch 3, Line 55, Col E)~~	$	#DIV/0!
2	20_ _ Applicable Company Revenues	Schedule 2, Line 1, Column C	$	-
3	Percentage Adjustment Applied to Customer's Bills ~~for EE~~	(Line 1 / Line 2)		0.0000%
	~~Distributed Generation Related Adjustment~~			
~~4~~	~~Total Lost Fixed Cost Revenue for Current Period~~	~~(Sch 2, Line 15, Col C * Sch 3, Line 56, Col E)~~	~~$~~	~~#DIV/0!~~
~~5~~	~~20_ _ Applicable Company Revenues~~	~~Schedule 2, Line 1, Column C~~	~~$~~	~~-~~
~~6~~	~~Percentage Adjustment Applied to Customer's Bills for DG~~	~~(Line 4 / Line 5)~~		~~0.0000%~~

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	20_ _ Applicable Company Revenues		$	-
2	Allowed Cap %			2.00% ~~1.00%~~
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	#VALUE!
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 83, Column C	$	#DIV/0!
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			0.00%
7	*Interest Accrued on Deferred Balance*	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	#DIV/0!
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10	Lost Fixed Cost Revenue - Billed [1]		$	-
11	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	#DIV/0!
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	#DIV/0!
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.0000%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	#DIV/0!

[1] Amount billed to customers for the collection period of 20_ _

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting
	Residential - Delivery Revenue - Demand					
	Energy Efficiency Savings					
1	Current Period			-	kW	
2	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 3, Column C		-	kW	
3	Cumulative Recoverable kW savings	(Line 1 + Line 2)		-	kW	
4	Total Recoverable EE Savings	Line 3		-	kW	
5	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW	
6	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 4 * Line 5)	$	#DIV/0!		
	Distributed Generation					
7	Current Period			-	kW	
8	Total Recoverable DG Savings	Line 7		-	kW	
9	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW	
10	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 8 * Line 9)	$	#DIV/0!		
	Residential - Delivery Revenue					
	Energy Efficiency Savings					
11	**Current Period**			-	kWh	
11a	% of Residential Customers choosing fixed option			0.0%		
11b	Estimated kWh reduction	(Line 1 * Line 2)		.....	kWh	
11c	Net Current Period	(Line 1 - Line 2)		.....	kWh	
12	**Prior Period kWh EE losses**	**Previous Filing, Schedule 3, Line 13, Column C**		-	**kWh**	
13	**Cumulative Recoverable kWh savings**	(Previous Filing, Schedule 3, Line 13, Column C + **Line 11 - Line 12**)		-	**kWh**	
14	**Total Recoverable EE Savings**	**Line 13**		-	**kWh**	
15	**Residential - Lost Fixed Cost Rate**	**Schedule 4, Line 3, Column C**	**$**	**#DIV/0!**	**$/kWh**	
16	**Residential - Lost Fixed Cost Revenue Relating to EE**	**(Line 14 * Line 15)**	**$**	**#DIV/0!**		
	Distributed Generation					
17	**Current Period**			-	**kWh**	
18	% of Residential Customers choosing fixed option			0.0%		
19	Estimated kWh reduction	(Line 26 * Line 21)		.....	kWh	
20	Net Current Period	(Line 19 - Line 18)		.....	kWh	
21	**Prior Period kWh DG losses**	**Previous Filing, Schedule 3, Line 15, Column C**		.....	kWh	
22	**Cumulative Recoverable kWh savings**	(Previous Filing, Schedule 3, Line 15, Column C + Line 19)		.....	kWh	
18	**Total Recoverable DG Savings**	**Line 17**		-	**kWh**	
19	**Residential - Lost Fixed Cost Rate**	**Schedule 4, Line 3, Column C**	**$**	**#DIV/0!**	**$/kWh**	
20	**Residential - Lost Fixed Cost Revenue Relating to DG**	**(Line 18 * Line 19)**	**$**	**#DIV/0!**		
	Small General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
21	Current Period			-	kW	
22	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 23, Column C		-	kW	
23	Cumulative Recoverable kW savings	(Line 21 + Line 22)		-	kW	
24	Total Recoverable EE Savings	Line 23		-	kW	
25	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
26	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 24 * Line 25)	$	#DIV/0!		
	Distributed Generation					
27	Current Period			-	kW	
28	Total Recoverable DG Savings	Line 27		-	kW	
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Workings
	Small General Service - Delivery Revenue					
	Energy Efficiency Savings					
31	Current Period			-	kWh	
32	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kWh	
33	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 33, Column C + Line 31 + Line 32)		-	kWh	
34	Total Recoverable EE Savings	Line 33		-	kWh	
35	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh	
36	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	#DIV/0!		
	Distributed Generation					
37	Current Period			-	kWh	
38	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 37, Column C		.....	kWh	
39	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 37, Column C + Line 38)		.....	kWh	
38	Total Recoverable DG Savings	Line 37		-	kWh	
39	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh	
40	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 38 * Line 39)	$	#DIV/0!		
	Medium General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
41	Current Period			-	kW	
42	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 43, Column C		-	kW	
43	Cumulative Recoverable kW savings	(Line 41 + Line 42)			kW	
44	Total Recoverable EE Savings	Line 43			kW	
45	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 19, Column C	$	#DIV/0!	$/kW	
46	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 44 * Line 45)	$	#DIV/0!		
	Distributed Generation					
47	Current Period				kW	
48	Total Recoverable DG Savings	Line 47		-	kW	
49	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 19, Column C	$	#DIV/0!	$/kW	
50	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 48 * Line 49)	$	#DIV/0!		
	Medium General Service - Delivery Revenue					
	Energy Efficiency Savings					
51	Current Period			-	kWh	
52	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 53, Column C		-	kWh	
53	Cumulative Recoverable kWh savings	(Line 51 + Line 52)		-	kWh	
54	Total Recoverable EE Savings	Line 53		-	kWh	
55	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
56	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 54 * Line 55)	$	#DIV/0!		
	Distributed Generation					
57	Current Period			-	kWh	
58	Total Recoverable DG Savings	Line 57		-	kWh	
59	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
60	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 58 * Line 59)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting	
	Large General Service - Delivery Revenue - Demand						
	Energy Efficiency Savings						
61	Current Period			-	kW		
62	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 63, Column C		-	kW		
63	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 63, Column C Line 61+ Line 62)		-	kW		
64	Total Recoverable EE Savings	Line 63		-	kW		
65	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 23, Column C	$	#DIV/0!	$/kW		
66	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 64 * Line 65)	$	#DIV/0!			
	Distributed Generation						
67	Current Period			-	kW		
68	Prior Period kW DG losses	Previous Filing, Schedule 3, Line 69, Column C		.....	kW		
69	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 69, Column C + Line 67)		.....	kW		
70	Total Recoverable DG Savings	Line 69		-	kW		
71	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 23, Column C	$	#DIV/0!	$/kW		
72	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 70 * Line 71)	$	#DIV/0!			
	Large General Service - Delivery Revenue						
	Energy Efficiency Savings						
71	Current Period			-	kWh		
72	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 73, Column C		-	kWh		
73	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 73, Column C Line 71+ Line 72)		-	kWh		
74	Total Recoverable EE Savings	Line 73		-	kWh		
75	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 23, Column C	$	#DIV/0!	$/kWh		
76	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 74 * Line 75)	$	#DIV/0!			
	Distributed Generation						
77	Current Period			-	kWh		
78	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 81, Column C		.....	kWh		
79	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 81, Column C + Line 49)		.....	kWh		
78	Total Recoverable DG Savings	Line 77		-	kWh		
79	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 23, Column C	$	#DIV/0!	$/kWh		
80	*Large General Service - Lost Fixed Cost Revenue Relating to DG*	(Line 78 * Line 79)	$	#DIV/0!			
						Percent of Total	
81	Total Lost Fixed Cost Revenue Related to Energy Efficiency	Sum Line 5 + 10 + 26 + 36 + 46 + 56 + 66 + 76	$	#DIV/0!		#DIV/0!	(Line 85 / Line 83)
82	Total Lost Fixed Cost Revenue Related to Distributed Generation	Sum Line 10 + 20 + 30 + 40 + 50 + 60 + 70 + 80	$	#DIV/0!		#DIV/0!	(Line 86 / Line 83)
83	Total Lost Fixed Cost Revenue	(Line 81 + Line 82)	$	#DIV/0!			

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rate

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
1	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15, Column C	$	#DIV/0!
2	20_ _ Applicable Company Revenues	Schedule 2, Line 1, Column C	$	-
3	Percentage Adjustment Applied to Customer's Bills	(Line 1 / Line 2)		0.0000%

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	20_ _ Applicable Company Revenues		$	-
2	Allowed Cap %			2.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	-
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 83, Column C	$	#DIV/0!
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			0.00%
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	#DIV/0!
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10	Lost Fixed Cost Revenue - Billed[1]		$	-
11	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	#DIV/0!
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	#DIV/0!
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.0000%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	#DIV/0!

[1] Amount billed to customers for the collection period of 20_ _

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential - Delivery Revenue - Demand				
	Energy Efficiency Savings				
1	Current Period			-	kW
2	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 3, Column C		-	kW
3	Cumulative Recoverable kW savings	(Line 1 + Line 2)		-	kW
4	Total Recoverable EE Savings	Line 3		-	kW
5	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW
6	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 4 * Line 5)	$	#DIV/0!	
	Distributed Generation				
7	Current Period			-	kW
8	Total Recoverable DG Savings	Line 7		-	kW
9	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW
10	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 8 * Line 9)	$	#DIV/0!	
	Residential - Delivery Revenue				
	Energy Efficiency Savings				
11	Current Period			-	kWh
12	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 13, Column C		-	kWh
13	Cumulative Recoverable kWh savings	(Line 11 + Line 12)		-	kWh
14	Total Recoverable EE Savings	Line 13		-	kWh
15	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	#DIV/0!	$/kWh
16	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 14 * Line 15)	$	#DIV/0!	
	Distributed Generation				
17	Current Period			-	kWh
18	Total Recoverable DG Savings	Line 17		-	kWh
19	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	#DIV/0!	$/kWh
20	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 18 * Line 19)	$	#DIV/0!	
	Small General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
21	Current Period			-	kW
22	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 23, Column C		-	kW
23	Cumulative Recoverable kW savings	(Line 21 + Line 22)		-	kW
24	Total Recoverable EE Savings	Line 23		-	kW
25	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW
26	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 24 * Line 25)	$	#DIV/0!	
	Distributed Generation				
27	Current Period			-	kW
28	Total Recoverable DG Savings	Line 27		-	kW
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	#DIV/0!	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Small General Service - Delivery Revenue				
	Energy Efficiency Savings				
31	Current Period			-	kWh
32	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kWh
33	Cumulative Recoverable kWh savings	(Line 31 + Line 32)		-	kWh
34	Total Recoverable EE Savings	Line 33		-	kWh
35	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh
36	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	#DIV/0!	
	Distributed Generation				
37	Current Period			-	kWh
38	Total Recoverable DG Savings	Line 37		-	kWh
39	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh
40	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 38 * Line 39)	$	#DIV/0!	
	Medium General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
41	Current Period			-	kW
42	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 43, Column C		-	kW
43	Cumulative Recoverable kW savings	(Line 41 + Line 42)		-	kW
44	Total Recoverable EE Savings	Line 43		-	kW
45	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW
46	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 44 * Line 45)	$	#DIV/0!	
	Distributed Generation				
47	Current Period			-	kW
48	Total Recoverable DG Savings	Line 47		-	kW
49	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW
50	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 48 * Line 49)	$	#DIV/0!	
	Medium General Service - Delivery Revenue				
	Energy Efficiency Savings				
51	Current Period			-	kWh
52	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 53, Column C		-	kWh
53	Cumulative Recoverable kWh savings	(Line 51 + Line 52)		-	kWh
54	Total Recoverable EE Savings	Line 53		-	kWh
55	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh
56	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 54 * Line 55)	$	#DIV/0!	
	Distributed Generation				
57	Current Period			-	kWh
58	Total Recoverable DG Savings	Line 57		-	kWh
59	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh
60	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 58 * Line 59)	$	#DIV/0!	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Large General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
61	Current Period			-	kW
62	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 63, Column C		-	kW
63	Cumulative Recoverable kW savings	(Line 61+ Line 62)		-	kW
64	Total Recoverable EE Savings	Line 63		-	kW
65	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW
66	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 64 * Line 65)	$	#DIV/0!	
	Distributed Generation				
67	Current Period			-	kW
68	Total Recoverable DG Savings	Line 67		-	kW
69	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW
70	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 68 * Line 69)	$	#DIV/0!	
	Large General Service - Delivery Revenue				
	Energy Efficiency Savings				
71	Current Period			-	kWh
72	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 73, Column C		-	kWh
73	Cumulative Recoverable kWh savings	(Line 71+ Line 72)		-	kWh
74	Total Recoverable EE Savings	Line 73		-	kWh
75	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh
76	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 74 * Line 75)	$	#DIV/0!	
	Distributed Generation				
77	Current Period			-	kWh
78	Total Recoverable DG Savings	Line 77		-	kWh
79	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh
80	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 78 * Line 79)	$	#DIV/0!	
81	Total Lost Fixed Cost Revenue Related to Energy Efficiency	Sum Line 6 + 16 + 26 + 36 + 46 + 56 + 66 + 76	$	#DIV/0!	
82	Total Lost Fixed Cost Revenue Related to Distributed Generation	Sum Line 10 + 20 + 30 + 40 + 50 + 60 + 70 + 80	$	#DIV/0!	
83	Total Lost Fixed Cost Revenue	(Line 81 + Line 82)	$	#DIV/0!	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation

Line No.	(A) LFCR Fixed Cost Calculation		(B) Reference		(C) Totals
	Residential Customers				
1		Delivery Revenue	Schedule 5, Line 9, Column E	$	-
2		kWh Billed	Schedule 5, Line 9, Column B		-
3		Lost Fixed Cost Rate	(Line 1 / Line 2)	$	#DIV/0!
	Residential Customers				
4		Delivery Revenue - Demand	Schedule 5, Line 24, Column E	$	-
5		kW Billed	Schedule 5, Line 24, Column B		-
6		Lost Fixed Cost Rate	(Line 4 / Line 5)	$	#DIV/0!
	Small General Service				
7		Delivery Revenue	Schedule 5, Line 14, Column E	$	-
8		kWh Billed	Schedule 5, Line 14, Column B		-
9		Lost Fixed Cost Rate	(Line 7 / Line 8)	$	#DIV/0!
	Small General Service				
10		Delivery Revenue - Demand	Schedule 5, Line 27, Column E	$	-
11		kW Billed	Schedule 5, Line 27, Column B		-
12		Lost Fixed Cost Rate	(Line 10 / Line 11)	$	#DIV/0!
	Medium General Service				
13		Delivery Revenue	Schedule 5, Line 17, Column E	$	-
14		kWh Billed	Schedule 5, Line 17, Column B		-
15		Lost Fixed Cost Rate	(Line 13 / Line 14)	$	#DIV/0!
	Medium General Service				
16		Delivery Revenue - Demand	Schedule 5, Line 30, Column E	$	-
17		kW Billed	Schedule 5, Line 30, Column B		-
18		Lost Fixed Cost Rate	(Line 16 / Line 17)	$	#DIV/0!
	Large General Service				
19		Delivery Revenue	Schedule 5, Line 20, Column E	$	-
20		kWh Billed	Schedule 5, Line 20, Column B		-
21		Lost Fixed Cost Rate	(Line 19 / Line 20)	$	#DIV/0!
	Large General Service				
22		Delivery Revenue - Demand	Schedule 5, Line 33, Column E	$	-
23		kW Billed	Schedule 5, Line 33, Column B		-
24		Lost Fixed Cost Rate	(Line 22 / Line 23)	$	#DIV/0!

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation

Line No.	(A) Rate Schedule	(B) Adjusted Test Year Billing Determinants	(C) Units	(D) Delivery Charge	(E) B x D Total Delivery Revenue
	kWh related				
1	Residential Service (RES)	-	kWh	$ -	$ -
2	Residential Service (RES-TOU)	-	kWh	$ -	$ -
3	Residential Service (RES-P-TOU)	-	kWh	$ -	$ -
4	Residential Service (RES-S)	-	kWh	$ -	$ -
5	Residential Service (RES-S-TOU)	-	kWh	$ -	$ -
6	Residential Service (RES-D)	-	kWh	$ -	$ -
7	Residential Service (RES-D-TOU)	-	kWh	$ -	$ -
8	Prepay Energy Service (PES)	-	kWh	$ -	$ -
9	Subtotal - kWh	-	kWh		$ -
10	Small General Service (SGS)	-	kWh	$ -	$ -
11	Small General Service (SGS-TOU)	-	kWh	$ -	$ -
12	Small General Service (SGS-D)	-	kWh	$ -	$ -
13	Small General Service (SGS-D-TOU)	-	kWh	$ -	$ -
14	Subtotal - kWh	-	kWh		$ -
15	Medium General Service (MGS)	-	kWh	$ -	$ -
16	Medium General Service (MGS-TOU)	-	kWh	$ -	$ -
17	Subtotal - kWh	-	kWh		$ -
18	Large General Service (LGS)	-	kWh	$ -	$ -
19	Large General Service (LGS-TOU)	-	kWh	$ -	$ -
20	Subtotal - kWh	-	kWh		$ -
21	Total kWh	-	kWh		$ -
	kW related				
22	Residential Service (RES-D)	-	kW	$ -	$ -
23	Residential Service (RES-D-TOU)	-	kW	$ -	$ -
24	Subtotal - kW	-	kW		$ -
25	Small General Service (SGS-D)	-	kW	$ -	$ -
26	Small General Service (SGS-D-TOU)	-	kW	$ -	$ -
27	Subtotal - kW	-	kW		$ -
28	Medium General Service (MGS)	-	kW	$ -	$ -
29	Medium General Service (MGS-TOU)	-	kW	$ -	$ -
30	Subtotal - kW	-	kW		$ -
31	Large General Service (LGS)	-	kW	$ -	$ -
32	Large General Service (LGS-TOU)	-	kW	$ -	$ -
33	Subtotal - kW	-	kW		$ -
34	Total kW	-	kW		$ -

REDLINE

TUCSON ELECTRIC POWER COMPANY
LOST FIXED COST RECOVERY MECHANISM ("LFCR")
PLAN OF ADMINISTRATION

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1. General Description

This document describes the plan of administration for the LFCR mechanism approved for Tucson Electric Power Company ("TEP" or "Company") by the Arizona Corporation Commission ("Commission~~ACC~~") in Decision No. xxxxx~~73912~~ (xxx. xx. xxxx~~June 27, 2013~~). The LFCR mechanism provides for the recovery of lost fixed costs, as measured by a reduction in non-fuel revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the ~~portion of transmission and distribution~~ non-fuel energy costs included in base rates~~ exclusive of the Customer Charge~~ and ~~50% of~~ the demand rates in effect, plus any amount quantified in the Balancing Account.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules~~, less the amount attributable to sales to those residential customers who chose the Fixed Cost Option~~.

Balancing Account – A mechanism to track the difference between allowed Lost Fixed Cost Revenue and actual amounts billed by the Company through the LFCR adjustment. The balancing account will be reflected in Schedule 2 of the LFCR Compliance Report and shall be calculated by taking the Total Lost Fixed Cost Revenue from Prior Period less the amount billed through the LFCR for the most recent collection period at the time of filing.

Current Period – The most recent~~ adjustment~~ calendar year used to determine lost sales for purposes of LFCR recovery~~measurement year~~.

~~Demand Stability Factor – Fifty percent of Demand based revenue (excluding any purchased power and fuel costs) produced by base rates.~~

~~Distribution and Transmission~~Delivery Revenue – The amount of revenue determined at the conclusion of a rate case by multiplying each participating rate class' adjusted test year billing determinants (kWh or kW) by their approved non-fuel energy and demand~~distribution and transmission related~~ charges.~~ This will be determined by reducing each class' total retail revenue~~

~~by the customer charge revenue, generation related revenue, purchased power and fuel costs and the Demand Stability Factor.~~

DG Savings – The amount of kWh or kW sales~~ or kW of capacity~~ reduced by DG. TEP will use meter data for determining the kWh or kW lost through the implementation of DG systems unless a rare circumstance occurs where the meter data is not available at which time the lost sales will be quantified using statistical verification or output profile or other Commission authorized methods. Each year, TEP will use actual data through December to calculate the savings. The calculation of DG ~~s~~Savings will consist of the following by class:

~~1. Cumulative Verified~~Current Period: The total kWh or kW reduction~~ as~~ metered ~~each year~~during the ~~measurement year~~period less the total kWh or kW reduction metered in TEP's most recent general rate case test year~~ (2011). The initial Cumulative Verified term of this LFCR will begin on January 1, 2013~~.

~~2.~~1. ~~Current Period: The annual kWh or kW produced by the cumulative total of DG installations since the end of the test year used in TEP's most recent general rate case.~~

~~3.~~ The only DG Savings that will be excluded from the~~ calculated~~ Lost Fixed Cost Revenue calculation are those kWh or kW that were lost as the result of actions by customers ~~in~~on the ~~e~~Excluded ~~r~~Rate Schedules~~classes~~.

2.

~~4.~~3. The annual kW capacity of the cumulative total of DG installations since the end of the test year used in TEP's most recent general rate case. For solar systems only, the actual kW capacity used to calculate lost revenues for applicable demand metered customers will be the actual solar generation measured by the Solar production meter coincident with the customer's maximum fifteen minute demand for the billing period.

~~Fixed Cost Option – The rate schedule choice for residential customers who prefer contributing to the recovery of Lost Fixed Cost Revenue in the form of an optional fixed rate added as an incremental charge to the Customer Charge in the applicable residential tariff rate. The total dollars paid as an incremental amount added to the otherwise effective Customer Charge will be accumulated over the Current Period and used to reduce the total Lost Fixed Cost Revenue recovered as part of the LFCR adjustment. The variable LFCR adjustment shall not be applied to residential customers who choose the Fixed Cost option. This rate will be reflected as an incremental addition to the customer charge on the otherwise effective tariff and made available to customers at the time of the first LFCR adjustment. Customers choosing this fixed option within the first twelve months subsequent to the initial effective date of the LFCR will be allowed to change back to the volumetric option one time without any penalties. After the initial twelve month period, customers will be required to stay on which ever option they choose for twelve full months before a change can be made.~~

EE Programs - Any program approved in TEP's Energy Efficiency/Demand Side Management ("EE/DSM") implementation plan or defined in the Commission's Electric Energy Efficiency Rules. ~~or Energy Efficiency Resource Plan.~~

EE Savings - The amount of sales, expressed in kWh or kW, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Research Report ("MER") conducted for TEP's EE Programs. The Company's EE activities are being reviewed as part of the MER evaluation and will determine the total kWh or kW lost as a result of those activities.

As part of this filing the Commission Staff will have the option of reviewing any portion of the filing they deem necessary to verify the filing's accuracy. EE Savings shall be quantified based on the cumulative lost kWh or kW occurring starting ~~January~~ July 1, ~~2013~~ 2015 and shall reset as of the end of the test year in each ~~subsequent~~ rate case. The calculation of EE Savings will consist of the following by class:

1. Current Period: The annual EE related sales reductions (kWh or kW). Each year, TEP will use actual MER data through December to calculate savings.
2. ~~1.~~ ~~Cumulative Verified~~Prior Period: The cumulative total kWh or kW reduction reported in the previous year's LFCR filing, ~~as determined by the MER~~ recognizing that the cumulative total is reset (to zero) at the end of each of TEP's most recent general rate case. The first such reset ~~will~~ was on~~be~~ January 1, 2012, (the end of the Test Year in Decision No. 73912.) Recovery of LFCR revenues quantified in the initial LFCR will continue until the first LFCR resulting from the current general rate case results in the specified reset to zero. With the approval of this rate case (Decision No. xxxxx) the cumulative total kWh and kW will be reset as of July 1, 2015 (the end of the test year) for calculations of the LFCR performed until reset in the Company's next general rate case. ~~The initial Cumulative Verified term of the LFCR will begin on January 1, 2013.~~
2. ~~Current Period: The annual EE related sales reductions (kWh or kW). Each year, TEP will use actual MER data through December to calculate savings.~~
3. Excluded kWh reduction: The reduction of recoverable EE Savings calculated by subtracting the amount of EE ~~s~~Savings actually achieved by customers on Excluded Rate Schedules if included in the total reported in the annual EE/DSM filing.

Effective Period – The twelve month period beginning with July 1 of each year, when the LFCR will be charged.

Excluded Rate Schedules – The LFCR mechanism shall not apply to Traffic Signal and Street Lighting Service (TSL~~PS-41~~), Lighting Service (LS~~GS-50~~), Water Pumping Service (GS-WP~~43~~), or the Large ~~Light and~~ Power Services (~~LLP-14 and LLP-90~~LPS-TOU and ~~LLP~~LPS-138) rate schedules, or the Residential Solar – Company Owned Program ~~(R-10)~~.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue ~~(As reduced by the total incremental fixed cost option dollars paid by the residential customers who have chosen the Fixed Cost Option and will be based on the incremental increase in the customer charge they have paid over the twelve months during the Current Period.)~~ by the Applicable Company Revenues.~~Current period's retail revenue (less the estimated sales to the residential customers who chose the Fixed Cost Option) during the Effective Period for the participating rate classes. This percentage based LFCR Adjustment will be presented on the customer's bills as two separate charges. These two charges will be developed by applying the weighted average proportion of the Energy Efficiency related lost revenues and the Distributed Generation related lost revenues as a proportion of total lost revenues falling under the 1% cap referenced herein. The weighted average proportions will be shown on Schedule 3 of this Plan of Administration.~~

~~These two separate percentage adjustment rates~~ This percentage-based LFCR Adjustment will be applied to all customer bills, excluding those ~~of~~on Excluded Rate Schedules.

Lost Fixed Cost Rate – A rate determined at the conclusion of a rate case by taking the sum of allowed ~~Distribution and Transmission~~Delivery Revenue (which excludes the ~~customer~~Basic Service ~~c~~Charge~~, the generation component~~ and purchased power and fuel) for each rate class and dividing each by their respective class adjusted test year kWh and/or kW billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE Savings and DG Savings during the Current Period~~measurement period~~. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh or kW Savings, by rate class.

Prior Period – The ~~twelve months in the~~ calendar year preceding the Current Period.

Recoverable kWh or kW Savings – The ~~sum of~~ EE Savings and DG Savings by applicable rate class.

3. *LFCR Annual Incremental Cap*

The total LFCR Adjustment will be subject to an annual ~~1~~2% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of ~~1~~2%, in total, of Applicable Company Revenues, any amount in excess of the ~~1~~2% cap will be deferred for collection until the next year its inclusion does not result in the 2% year-over-year cap being exceeded. Any deferred amounts, plus any amount quantified in the Balancing Account, will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the ~~1~~2% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharges billed in the following year will first recover any such carried-over deferrals, as well as any Balancing Account balance, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

~~The initial LFCR filing will reconcile unrecovered lost revenues from January 1, 2013 through December 31, 2013.~~

4. *Filing and Procedural Deadlines*

TEP will file the calculated Annual LFCR Adjustments, including all Compliance Reports, with the Commission for the previous year by May 15th of each year. Staff will use its best efforts to process the matter based on the results of the Company's annual EE/DSM and Renewable Energy Standard Tariff ("REST") filings such that a new LFCR ~~a~~Adjustments may go into effect by July 1st of each year. However, the new LFCR Adjustment will not go into effect until approved by the Commission.

5. *Compliance Reports*

TEP will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office by May 15th of each year. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1 : LFCR Annual Percentage Adjustment Rate~~s~~
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: ~~Distribution and Transmission~~Delivery Revenue Calculation

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rate~~s~~

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
	~~Energy Efficiency Related Adjustment~~			
1	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15, Column C ~~(Sch 2, Line 15, Col C * Sch 3, Line 55, Col E)~~	$	#DIV/0!
2	20_ _ Applicable Company Revenues	Schedule 2, Line 1, Column C	$	-
3	Percentage Adjustment Applied to Customer's Bills ~~for EE~~	(Line 1 / Line 2)		0.0000%
	~~Distributed Generation Related Adjustment~~			
~~4~~	~~Total Lost Fixed Cost Revenue for Current Period~~	~~(Sch 2, Line 15, Col C * Sch 3, Line 56, Col E)~~	~~$~~	~~#DIV/0!~~
~~5~~	~~20_ _ Applicable Company Revenues~~	~~Schedule 2, Line 1, Column C~~	~~$~~	~~-~~
~~6~~	~~Percentage Adjustment Applied to Customer's Bills for DG~~	~~(Line 4 / Line 5)~~		~~0.0000%~~

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	20_ _ Applicable Company Revenues		$	-
2	Allowed Cap %			2.00% 1.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	#VALUE!
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 83, Column C	$	#DIV/0!
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			0.00%
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	#DIV/0!
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10	Lost Fixed Cost Revenue - Billed[1]		$	-
11	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	#DIV/0!
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	#DIV/0!
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.0000%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	#DIV/0!

[1] Amount billed to customers for the collection period of 20_ _

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Workpaper
	Residential - Delivery Revenue - Demand					
	Energy Efficiency Savings					
1	Current Period			-	kW	
2	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 3, Column C		-	kW	
3	Cumulative Recoverable kW savings	(Line 1 + Line 2)		-	kW	
4	Total Recoverable EE Savings	Line 3		-	kW	
5	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW	
6	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 4 * Line 5)	$	#DIV/0!		
	Distributed Generation					
7	Current Period			-	kW	
8	Total Recoverable DG Savings	Line 7		-	kW	
9	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW	
10	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 8 * Line 9)	$	#DIV/0!		
	Residential - Delivery Revenue					
	Energy Efficiency Savings					
11	**Current Period**			-	kWh	
12	**Prior Period kWh EE losses**	Previous Filing, Schedule 3, Line 15, Column C		-	kWh	
13	**Cumulative Recoverable kWh savings**	(Line 11 + Line 12)		-	kWh	
14	**Total Recoverable EE Savings**	Line 13		-	kWh	
15	**Residential - Lost Fixed Cost Rate**	Schedule 4, Line 3, Column C	$	#DIV/0!	$/kWh	
16	**Residential - Lost Fixed Cost Revenue Relating to EE**	(Line 14 * Line 15)	$	#DIV/0!		
	Distributed Generation					
17	**Current Period**			-	kWh	
18	**% of Residential Customers choosing Rate option**			0.0%		
19	**Excludes kWh reduction**	(Line 20 * Line 11)			kWh	
20	**Net Current Period**	(Line 19 - Line 18)			kWh	
21	**Prior Period kWh DG losses**	Previous Filing, Schedule 3, Line 15, Column C			kWh	
22	**Cumulative Recoverable kWh savings**	(Previous Filing, Schedule 3, Line 15, Column C + Line 20)			kWh	
23	**Total Recoverable DG Savings**	Line 17		-	kWh	
24	**Residential - Lost Fixed Cost Rate**	Schedule 4, Line 3, Column C	$	#DIV/0!	$/kWh	
25	**Residential - Lost Fixed Cost Revenue Relating to DG**	(Line 18 * Line 19)	$	#DIV/0!		
	Small General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
21	Current Period			-	kW	
22	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 23, Column C			kW	
23	Cumulative Recoverable kW savings	(Line 21 + Line 22)		-	kW	
24	Total Recoverable EE Savings	Line 23			kW	
25	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
26	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 24 * Line 25)	$	#DIV/0!		
	Distributed Generation					
27	Current Period			-	kW	
28	Total Recoverable DG Savings	Line 27		-	kW	
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Workings
	Small General Service - Delivery Revenue					
	Energy Efficiency Savings					
31	Current Period			-	kWh	
32	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kWh	
33	Cumulative Recoverable kWh savings	(~~Previous Filing, Schedule 3, Line 34, Column C~~ Line 31 + Line 32)		-	kWh	
34	**Total Recoverable EE Savings**	Line 33		-	kWh	
35	**Small General Service - Lost Fixed Cost Rate**	**Schedule 4, Line 9, Column C**	$	#DIV/0!	$/kWh	
36	**Small General Service - Lost Fixed Cost Revenue Relating to EE**	**(Line 34 * Line 35)**	$	#DIV/0!		
	Distributed Generation					
37	**Current Period**			-	kWh	
38	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line 37, Column C~~		.....	~~kWh~~	
39	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line 37, Column C + Line 38)~~		.....	~~kWh~~	
40	**Total Recoverable DG Savings**	**Line 37**		-	kWh	
41	**Small General Service - Lost Fixed Cost Rate**	**Schedule 4, Line 9, Column C**	$	#DIV/0!	$/kWh	
42	**Small General Service - Lost Fixed Cost Revenue Relating to DG**	**(Line 38 * Line 39)**	$	#DIV/0!		
	Medium General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
43	Current Period			-	kW	
44	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 43, Column C		-	kW	
45	Cumulative Recoverable kW savings	(Line 43 + Line 44)		-	kW	
46	Total Recoverable EE Savings	Line 45			kW	
47	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW	
48	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 46 * Line 47)	$	#DIV/0!		
	Distributed Generation					
49	Current Period			-	kW	
50	Total Recoverable DG Savings	Line 49		-	kW	
51	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW	
52	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 50 * Line 51)	$	#DIV/0!		
	Medium General Service - Delivery Revenue					
	Energy Efficiency Savings					
53	Current Period			-	kWh	
54	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 53, Column C		-	kWh	
55	Cumulative Recoverable kWh savings	(Line 53 + Line 54)		-	kWh	
56	Total Recoverable EE Savings	Line 55		-	kWh	
57	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
58	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 56 * Line 57)	$	#DIV/0!		
	Distributed Generation					
59	Current Period			-	kWh	
60	Total Recoverable DG Savings	Line 59		-	kWh	
61	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
62	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 58 * Line 59)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting
	Large General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
61	Current Period			-	kW	
62	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 63, Column C		-	kW	
63	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 63, Column C Line 61+ Line 62)		-	kW	
64	Total Recoverable EE Savings	Line 63		-	kW	
65	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW	
66	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 64 * Line 65)	$	#DIV/0!		
	Distributed Generation					
67	Current Period			-	kW	
68	Prior Period kW DG losses	Previous Filing, Schedule 3, Line 70, Column C		.....	kW	
69	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 68, Column C + Line 67)		.....	kW	
70	Total Recoverable DG Savings	Line 69		-	kW	
71	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW	
72	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 70 * Line 71)	$	#DIV/0!		
	Large General Service - Delivery Revenue					
	Energy Efficiency Savings					
73	Current Period			-	kWh	
74	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 73, Column C		-	kWh	
75	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 75, Column C Line 73+ Line 74)		-	kWh	
76	Total Recoverable EE Savings	Line 75		-	kWh	
77	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kWh	
78	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 76 * Line 77)	$	#DIV/0!		
	Distributed Generation					
79	Current Period			-	kWh	
80	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 81, Column C		.....	kWh	
81	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 81, Column C + Line 80)		.....	kWh	
82	Total Recoverable DG Savings	Line 81		-	kWh	
83	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kWh	
84	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 82 * Line 83)	$	#DIV/0!		
						Rounded Total
85	Total Lost Fixed Cost Revenue Related to Energy Efficiency	Sum Line 6 + Line 26 + Line 46 + Line 66 + Line 78	$	#DIV/0!		#DIV/0! Line 85 - Line 86
86	Total Lost Fixed Cost Revenue Related to Distributed Generation	Sum Line 10 + Line 30 + Line 50 + Line 70 + Line 84	$	#DIV/0!		#DIV/0! Line 85 - Line 85
87	Total Lost Fixed Cost Revenue	(Line 85 + Line 86)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation

Line No.	(A) LFCR Fixed Cost Calculation	(B) Reference		(C) Totals
	Residential Customers			
1	Delivery Revenue	Schedule 5, Line 9, Column E	$	-
2	kWh Billed	Schedule 5, Line 9, Column B		-
3	Lost Fixed Cost Rate	(Line 1 / Line 2)	$	#DIV/0!
	Residential Customers			
4	Delivery Revenue - Demand	Schedule 5, Line 24, Column E	$	-
5	kW Billed	Schedule 5, Line 24, Column B		-
6	Lost Fixed Cost Rate	(Line 4 / Line 5)	$	#DIV/0!
	Small General Service			
7	Delivery Revenue	Schedule 5, Line 14, Column E	$	-
8	kWh Billed	Schedule 5, Line 14, Column B		-
9	Lost Fixed Cost Rate	(Line 7 / Line 8)	$	#DIV/0!
	Small General Service			
10	Delivery Revenue - Demand	Schedule 5, Line 27, Column E	$	-
11	kW Billed	Schedule 5, Line 27, Column B		-
12	Lost Fixed Cost Rate	(Line 10 / Line 11)	$	#DIV/0!
	Medium General Service			
13	Delivery Revenue	Schedule 5, Line 17, Column E	$	-
14	kWh Billed	Schedule 5, Line 17, Column B		-
15	Lost Fixed Cost Rate	(Line 13 / Line 14)	$	#DIV/0!
	Medium General Service			
16	Delivery Revenue - Demand	Schedule 5, Line 30, Column E	$	-
17	kW Billed	Schedule 5, Line 30, Column B		-
18	Lost Fixed Cost Rate	(Line 16 / Line 17)	$	#DIV/0!
	Large General Service			
19	Delivery Revenue	Schedule 5, Line 20, Column E	$	-
20	kWh Billed	Schedule 5, Line 20, Column B		-
21	Lost Fixed Cost Rate	(Line 19 / Line 20)	$	#DIV/0!
	Large General Service			
22	Delivery Revenue - Demand	Schedule 5, Line 33, Column E	$	-
23	kW Billed	Schedule 5, Line 33, Column B		-
24	Lost Fixed Cost Rate	(Line 22 / Line 23)	$	#DIV/0!
	~~Large General Service~~			
~~10~~	~~Delivery Revenue~~	~~Schedule 5, Line 14, Column E~~	~~$~~	~~-~~
~~11~~	~~kWh Billed~~	~~Schedule 5, Line 14, Column B~~		~~-~~
~~12~~	~~Lost Fixed Cost Rate~~	~~(Line 10 / Line 11)~~	~~$~~	~~#DIV/0!~~

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation

Line No.	(A) Rate Schedule	(B) Adjusted Test Year Billing Determinants	(C) Units	(D) Delivery Charge	~~(E)~~ ~~Demand Stability Factor~~	~~(F)~~ (E) B x D ~~x E~~ Total Delivery Revenue
	kWh related					
1	Residential Service (RES-~~01~~)	-	kWh	$ -	~~100%~~	$ -
2	Residential Service (RES-TOU~~90~~)	-	kWh	$ -	~~100%~~	$ -
3	Residential Service (RES-P-TOU)	-	kWh	$ -		$ -
4	Residential Service (RES-~~52014N~~)	-	kWh	$ -	~~100%~~	$ -
5	Residential Service (RES-5-TOU~~20180N~~)	-	kWh	$ -	~~100%~~	$ -
6	Residential Service (RES-D)	-	kWh	$ -		$ -
7	Residential Service (RES-D-TOU)	-	kWh	$ -		$ -
8	Prepay Energy Service (PES)	-	kWh	$ -		$ -
9	Subtotal - kWh	-	kWh			$ -
10	Small General Service (SGS-~~10~~)	-	kWh	$ -	~~100%~~	$ -
11	Small General Service (SGS-TOU~~75~~)	-	kWh	$ -	~~100%~~	$ -
12	Small General Service (SGS-D)	-	kWh	$ -		$ -
13	Small General Service (SGS-D-TOU)	-	kWh	$ -		$ -
14	Subtotal - kWh	-	kWh			$ -
15	Medium General Service (MGS)	-	kWh	$ -		$ -
16	Medium General Service (MGS-TOU)	-	kWh	$ -		$ -
17	Subtotal - kWh	-	kWh			$ -
18	Large General Service (LGS)	-	kWh	$ -		$ -
19	Large General Service (LGS-TOU)	-	kWh	$ -		$ -
20	Subtotal - kWh	-	kWh			$ -
21	Total kWh	-	kWh			$ -
	kW related					
22	Residential Service (RES-D)	-	kW	$ -		$ -
23	Residential Service (RES-D-TOU)	-	kW	$ -		$ -
24	Subtotal - kW	-	kW			$ -
25	Small General Service (SGS-D)	-	kW	$ -		$ -
26	Small General Service (SGS-D-TOU)	-	kW	$ -		$ -
27	Subtotal - kW	-	kW			$ -
28	Medium General Service (MGS)	-	kW	$ -		$ -
29	Medium General Service (MGS-TOU)	-	kW	$ -		$ -
30	Subtotal - kW	-	kW			$ -
31	Large General Service (LGS-~~13~~) ~~- kW~~	-	kW	$ -	~~50%~~	$ -
32	Large General Service (LGS-TOU~~85~~) ~~- kW~~	-	kW	$ -	~~50%~~	$ -
33	Subtotal - kW ~~- Demand~~	-	kW			$ -
34	Total kW	-	kW			$ -
~~12~~	~~Large General Service (LGS-13)~~		~~kWh~~	~~$~~	~~100%~~	~~$~~
~~13~~	~~Large General Service (LGS-85)~~		~~kWh~~	~~$~~	~~100%~~	~~$~~
~~14~~	~~Subtotal - kWh - Delivery~~		~~kWh~~			~~$~~

Exhibit CAJ-6

CLEAN

Plan of Administration

Environmental Compliance Adjustor ("ECA")

Table of Contents

1. General Description 1
2. Definitions 1
3. ECA Qualified Investments - FERC Accounts 2
4. Calculation of ECA Revenue Requirement 2
5. Calculation of ECA Percentage Rate 3
6. Filing and Procedural Deadlines 3

1. GENERAL DESCRIPTION

This document describes the plan of administration for the Environmental Compliance Adjustor ("ECA") approved for Tucson Electric Power Company ("TEP") by the Arizona Corporation Commission ("Commission") in Decision No. xxxxx [DATE]. The ECA provides for the recovery of capital carrying costs and incremental O&M costs related to environmental investments made by TEP and not already recovered in base rates approved in Decision No. xxxxx or recovered through another Commission approved adjustment. The ECA will be calculated annually based on the ECA Qualified Investments closed to plant-in-service and ECA Qualified Investments included in Construction Work in Progress during the preceding calendar year.

2. DEFINITIONS

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

ECA Qualified Investments - Investments in Qualified Environmental Compliance projects. Each ECA Qualified Investment shall: 1) be classified in one or more of the FERC plant or Construction Work in Progress accounts listed in Section 3 of this document, or any other successor FERC account, upon going into service, and 2) be tracked by a specific project number.

Qualified Environmental Compliance Projects - Qualified ECA investments include those projects designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws and regulations. In general, these environmental standards apply to the following: sulfur dioxide, nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury and other toxics, coal ash and other combustion residuals and water intake.

Total kWh Sales – The total prior calendar kWh sales served under applicable ACC jurisdictional electric rate schedules as reported in the Company's FERC Form No. 1.

3. ECA QUALIFIED INVESTMENTS - FERC ACCOUNTS

Steam Production:

- FERC Account 310 – Land and Land Rights
- FERC Account 311 – Structures and Improvements
- FERC Account 312 – Boiler Plant Equipment
- FERC Account 313 – Engines and Engine-Driven Generators
- FERC Account 314 – Turbogenerator Units
- FERC Account 315 – Accessory Electric Equipment
- FERC Account 316 – Miscellaneous Power Plant Equipment

Other Production:

- FERC Account 340 – Land and Land Rights
- FERC Account 341 – Structures and Improvements
- FERC Account 342 – Fuel Holders, Products and Accessories
- FERC Account 343 – Prime Movers
- FERC Account 344 – Generators
- FERC Account 345 – Accessory Electric Equipment
- FERC Account 346 – Miscellaneous Power Plant Equipment

Construction Work In Progress – Electric

- FERC Account 107

Please note this list may expand to include other accounts approved by the Commission in the future.

4. CALCULATION OF ECA REVENUE REQUIREMENT

The recoverable ECA costs will be subject to an annual 0.5% year-over-year cap based on Applicable Company Revenues. The costs used in calculating the ECA Percentage Rate will include:

- Return on ECA Qualified Investments (Plant in Service and CWIP) based on TEP's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX;
- For plant in-service:
    - Depreciation expense;
    - Income Taxes;
    - Property taxes;
    - Deferred taxes and tax credits where applicable; and
    - Operation and Maintenance costs.

The ECA Qualified Projects and the ECA recoverable costs calculation will be submitted by the company to the Commission in the form of Schedule 1 and Schedule 2 as attached to this document.

5. CALCULATION OF ECA PERCENTAGE RATE

The ECA rate to be applied to customers' bills will be calculated by dividing the total ECA recoverable costs by Applicable Company Revenues.

6. FILING AND PROCEDURAL DEADLINES

TEP will file the calculated ECA rate including all supporting data with the Commission for the previous year on or before March 1. See schedules 1 and 2, attached.

The Commission staff and interested parties shall have the opportunity to review the ECA filing and supporting data. Unless the Commission has otherwise acted or Commission Staff has filed an objection by May 1, the new ECA rate proposed by TEP will go into effect with the first billing cycle in May (without proration) and will remain effect for the following 12-month period.

Schedule 1: Qualified Investments for ECA

Electric Plant in Service

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
1.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
2.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
3.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
4.		Total			$ -	$ -

Construction Work In Progress - Electric

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) Expected In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
5.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
6.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
7.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
8.		Total			$ -	$ -
9.		Total Qualified Investments (Line 4 + Line 8)			$ -	$ -

Billing Period XX/XX/20XX - XX/XX/20XX

Line No.	ECA Rate Calculation		
	Qualified Net Plant		
1.	Environmental Improvement Projects (Schedule 1 - Total Line Column F)	$	-
2.	Accumulated Depreciation	$	-
3.	Cumulative Deferred Tax/Tax Credits	$	-
4.	Qualified Net Plant (Line 1 - Line 2 - Line 3)	$	-
5.	Pre-Tax Weighted Average Cost of Capital		0.00%
	Capital Carrying Costs		
6.	Composite Return on ECA Net Plant (Line 4 * Line 5)	$	-
7.	Annual Depreciation of Plant in Service	$	-
8.	Applicable Property Tax	$	-
9.	Associated O&M Expense	$	-
10.	Total ECA Capital Carrying Costs (Line 6 + Line 7 + Line 8 + Line 9)	$	-
11.	Applicable Company Revenues		-
12.	Calculated ECA Rate as Percentage (Line 10 / Line 11)		0.0000%
13.	Prior Year's Calculated ECA Rate as a Percentage (Line 16, prior year)		0.0000%
14.	Year over Year increase (Limited to 0.5%)		0.0000%
15.	Amount in excess of 0.5% (Line 14 less .05%)		0.0000%
16.	Current Year's ECA Rate (Line 12 - line 15)		0.0000%

REDLINE

Plan of Administration

Environmental Compliance Adjustor ("ECA")

Table of Contents

1. General Description 1
2. Definitions 1
3. ECA Qualified Investments - FERC Accounts 2
4. Calculation of ECA Revenue Requirement 2
5. Calculation of ECA ~~$ per kWh~~Percentage Rate 3
6. Filing and Procedural Deadlines 3

1. GENERAL DESCRIPTION

This document describes the plan ~~for~~ of ~~administering~~ administration for the Environmental Compliance Adjustor ("ECA") ~~the Arizona Corporation Commission ("Commission")~~ approved for Tucson Electric Power Company ("TEP") by the Arizona Corporation Commission ("Commission") in Decision No. xxxxx [DATE]. The ECA provides for the recovery of capital carrying costs and incremental O&M costs related to environmental investments made by TEP and not already recovered in base rates approved in Decision No. xxxxx or recovered through another Commission approved adjustment. The ECA will be calculated annually based on the ECA Qualified Investments closed to plant-in-service and ECA Qualified Investments included in Construction Work in Progress during the preceding calendar year.

2. DEFINITIONS

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

ECA Qualified Investments - Investments in Qualified Environmental Compliance projects. Each ECA Qualified Investment shall: 1) be classified in one or more of the FERC plant or Construction Work in Progress accounts listed in Section 3 of this document, or any other successor FERC account, upon going into service, and 2) be tracked by a specific project number.

Qualified Environmental Compliance Projects - Qualified ECA investments include those projects designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws and regulations. In general, these environmental standards apply to the following: sulfur dioxide, nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury and other toxics, coal ash and other combustion residuals and water intake.

Total kWh Sales – The total prior calendar kWh sales served under applicable ACC jurisdictional electric rate schedules as reported in the Company's FERC Form No. 1.

3. ECA QUALIFIED INVESTMENTS - FERC ACCOUNTS

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- FERC Account 310 – Land and Land Rights
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- FERC Account 315 – Accessory Electric Equipment
- FERC Account 316 – Miscellaneous Power Plant Equipment

Other Production:

- FERC Account 340 – Land and Land Rights
- FERC Account 341 – Structures and Improvements
- FERC Account 342 – Fuel Holders, Products and Accessories
- FERC Account 343 – Prime Movers
- FERC Account 344 – Generators
- FERC Account 345 – Accessory Electric Equipment
- FERC Account 346 – Miscellaneous Power Plant Equipment

Construction Work In Progress – Electric

- FERC Account 107

Please note this list may expand to include other accounts approved by the Commission~~ACC~~ in the future.

4. CALCULATION OF ECA REVENUE REQUIREMENT

The recoverable ECA costs will be subject to an annual ~~2~~0.5% year-over-year cap based on Applicable Company Revenues. The costs used in calculating the ECA ~~used in calculating the ECA $ per kWh~~ Percentage R~~r~~ate will include:

- Return on ECA Qualified Investments (Plant in Service and CWIP) based on TEP's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX~~xx~~;
- For plant in-service:
  - Depreciation expense;
  - -Income Taxes;
  - Property taxes;
  - Deferred taxes and tax credits where applicable; and
  - Operation and Maintenance costs.

The ECA Qualified Projects and the ECA recoverable costs calculation will be submitted by the company to the Commission~~ACC~~ in the form of Schedule 1 and Schedule 2 as attached to this document.

5. CALCULATION OF ECA ~~$ PER KWH~~PERCENTAGE RATE

The ECA rate to be applied to customers' bills will be calculated by dividing the total ECA recoverable costs by ~~Total kWh Sales~~Applicable Company Revenues.

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6. FILING AND PROCEDURAL DEADLINES

TEP will file the calculated ECA rate including all supporting data with the Commission for the previous year on or before March 1. See schedules 1 and 2, attached.

The Commission staff and interested parties shall have the opportunity to review the ECA filing and supporting data. Unless the Commission has otherwise acted or Commission Staff has filed an objection by May 1, the new ECA rate proposed by TEP will go into effect with the first billing cycle in May (without proration) and will remain effect for the following 12-month period.

Schedule 1: Qualified Investments for ECA

Electric Plant in Service

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
1.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
2.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
3.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
4.		Total			$ -	$ -

Construction Work In Progress - Electric

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) Expected In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
5.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
6.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
7.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
8.		Total			$ -	$ -
9.		Total Qualified Investments (Line 4 + Line 8)			$ -	$ -

Schedule 2: Capital Carrying Costs and Adjustor Calculation
Plant in Service for Calendar Year 20XX
Billing Period ~~4/1/20XX-3/30/XX~~XX/XX/20XX - XX/XX/20XX

Line No.	ECA Rate Calculation		
	Qualified Net Plant		
1.	Environmental Improvement Projects (Schedule 1 - Total Line Column F)	$	-
2.	Accumulated Depreciation	$	-
3.	Cumulative Deferred Tax/Tax Credits	$	-
4.	Qualified Net Plant (Line 1 - Line 2 - Line 3)	$	-
5.	Pre-Tax Weighted Average Cost of Capital		0.00%
	Capital Carrying Costs		
6.	Composite Return on ECA Net Plant (Line 4 * Line 5)	$	-
7.	Annual Depreciation of Plant in Service	$	-
8.	Applicable Property Tax	$	-
9.	Associated O&M Expense	$	-
10.	Total ECA Capital Carrying Costs (Line 6 + Line 7 + Line 8 + Line 9)	$	-
11.	~~Total Company Retail Sales (kWh)~~Applicable Company Revenues		-
12.	Calculated ECA Rate as Percentage ~~($/kWh)~~ (Line 10 / Line 11)		0.0000%
13.	Prior Year's Calculated ECA Rate as a Percentage (Line 16, prior year)		0.0000%
14.	Year over Year increase (Limited to 0.5%)		0.0000%
15.	Amount in excess of 0.5% (Line 14 less .05%)		0.0000%
16.	Current Year's ECA Rate (Line 12 - line 15)		0.0000%